# Bear Valley Electric Service 2023-2025 Wildfire Mitigation Plan

2023 Revision 2

*Submitted by:*

Bear Valley Electric Service, Inc.

November 16, 2023

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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 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 Light Detection and Ranging (LiDAR) surveys) 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 reanalysis 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 fires spread simulations across the 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 High-Definition (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 Supervisory Control and Data Acquisition (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 advanced 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 Unmanned Aerial Vehicle (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 advanced 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 full-time 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 databases, 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 Geographic Information Systems (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 Office of Energy Infrastructure Safety (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 due to 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 Big Bear Fire Department (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 California Highway Patrol (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, table-top 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 AFN 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. BVES Table 2-1, shown below, outlines leadership roles regarding implementation and monitoring of the WMP and their relevant responsibilities.

**BVES 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<br>909-202-9539 | Entire Section |

| Name | Title | Email | Phone Number | Component |
|---|---|---|---|---|
| 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 |

| Name | Title | Email | Phone Number | Component |
|---|---|---|---|---|
| Jon Pecchia | Utility Manager | Jon.Pecchia@bvesinc.com | 909.866.4678 x102<br>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<br>909-202-9539 | Entire Section |
| Section 11: Corrective Action Program | | | | |
| Jon Pecchia | Utility Manager | Jon.Pecchia@bvesinc.com | 909.866.4678 x102<br>909.253.8966 | Entire Section |
| Section 12: Notices of Violation and Defect | | | | |
| Jon Pecchia | Utility Manager | Jon.Pecchia@bvesinc.com | 909.866.4678 x102<br>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, p. 25 [infrastructure]<br>Section 7, p. 63-65 [risk mitigation] |
| (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, p. 7-10 |
| (c) (1) | Provide list of persons responsible for executing the WMP and each members responsibility in the process. | Section 2, p. 11-13 |
| (c) (2) | The objectives of the WMP | Section 4.1, p. 19 |
| (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, p. 48-51 [risk of catastrophic wildfires]<br>Section 7, p. 62-69 [risk evaluation and prioritization] |

| PUC Section 8386 | Description | WMP Section |
|---|---|---|
| (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, p. 46-48 |
| (c) (5) | A discussion of how the application of previously identified metrics to previous plan performances has informed the plan. | Section 6, p. 42 [overview of plan]<br>Section 8, p. 176-180 [QA/QC]<br>Section 11, p. 308-313 [corrective action program] |
| (c) (6) | A description of BVES's protocols for disabling reclosers and de-energizing portions of the electrical distribution system that consider the associated impacts on public safety. As part of these protocols, each electrical corporation shall include protocols related to mitigating the public safety impacts of disabling reclosers and de-energizing portions of the electrical distribution system that impacts critical first responders. | Section 8, p. 214-215 |
| (c) (7) | A description of BVES's appropriate and feasible procedures for notifying a customer who may be impacted by the de-energizing of electrical lines, including procedures for those customers receiving 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 | Section 8.4.4.1, p. 250-252 |

| PUC Section 8386 | Description | WMP Section |
|---|---|---|
| | Commission regarding notifications of de-energization events. | |
| (c) (8) | Identification of circuits that have frequently been de-energized pursuant to a de-energization event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by 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, p. 20 [proposed expenditures]<br>Section 8, p. 125 [circuit breakers] p. 275-276 [discussion of frequently de-energized circuits] |
| (c) (9) | Plans for vegetation management. | Section 7, p. 77-78 [3 and 10-year plans for vegetation management]<br>Section 8, p. 150-185 [vegetation management and inspection] |
| (c) (10) | Protocols for the PSPS of BVES's transmission infrastructure, etc. | Section 5, p. 38-40 |
| (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, p. 20-23 [risk-informed framework used]<br>Section 8, p. 215-216 [emergency preparedness] |
| (c) (12) | A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout BVES's service territory such | Section 7, p. 66-69 [prioritized list of risks]<br>Section 8, p. 100-117 [planned activities and associated risks] |

| PUC Section 8386 | Description | WMP Section |
|---|---|---|
| | 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 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, p. 44-46 [accounting for wildfire risk] Section 7, p. 71 [Risk Assessment Mitigation Phase filing] |
| (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, p. 37-39 [actions to be taken to ensure emergency preparedness] Section 8, p. 100-117 [planned activities and expected system impacts] |
| (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 8.1.2.2, p. 134 |
| (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, p. 65-66 [stakeholder roles for decision making] Section 8, p. 138-149, p. 179-185 [workforce planning] |
| (c) (17) | Identification of any geographic area in BVES's | Section 5.3.3, p. 30 Section 6.4.1.1, p. 74 |

| PUC Section 8386 | Description | WMP Section |
|---|---|---|
| | 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, p. 57 |
| (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. | Section 7, p. 74-83 [wildfire mitigation strategy]<br>Section 8, p. 260-273 [community outreach and engagement] |
| (c) (20) | A statement of how BVES will restore service after a wildfire. | Section 8, p. 253-256 [planning for service restoration]<br>Section 9, p. 293-295 [allocation of resources for service restoration] |
| (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, p. 38-39 [communities at risk from wildfire]<br>Section 8, p. 259-261 [customer support in wildfire and PSPS emergencies] |
| (c) (22) | Description of the processes and procedures used to monitor and audit the WMP, identify and correct WMP deficiencies, and assess the | Section 1, p. 1-10 [summary of WMP cycles]<br>Section 8, p. 117-123 [asset inspections] |

| PUC Section 8386 | Description | WMP Section |
|---|---|---|
| | effectiveness of electrical line and equipment inspections. | Section 10, p. 296-307 [lessons learned] |
| (c) (23) | Provide a list of persons responsible for executing the WMP and each members responsibility in the process. | Section 2, p. 11-13 |

# 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 2023-2025 WMP cycle, 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.

The following list provides greater detail to the objectives over the 2023-2025 WMP cycle:

- 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, table-top 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 AFN 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.

## 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 US 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<br><br>Actual = $9,154<br><br>± △ = ($2,262) |
| 2021 | Planned = $15,218<br><br>Actual = $12,088<br><br>± △ = ($3,130) |
| 2022 | Planned = $16,109 |

| Year | Spend (Thousands $USD) |
|---|---|
| | Actual = $15,232<br><br>± △ = ($877) |
| 2023 | Planned = $25,852 |
| 2024 | Planned = $43,620 |
| 2025 | Planned = $18,301 |

## 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 cross-disciplinary 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 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, |

| Risk-Informed Approach Component | Brief Description |
|---|---|
| | 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.<br><br>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, |

| Risk-Informed Approach Component | Brief Description |
|---|---|
| | 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 following figure and table provide a high-level description of BVES's service territory.

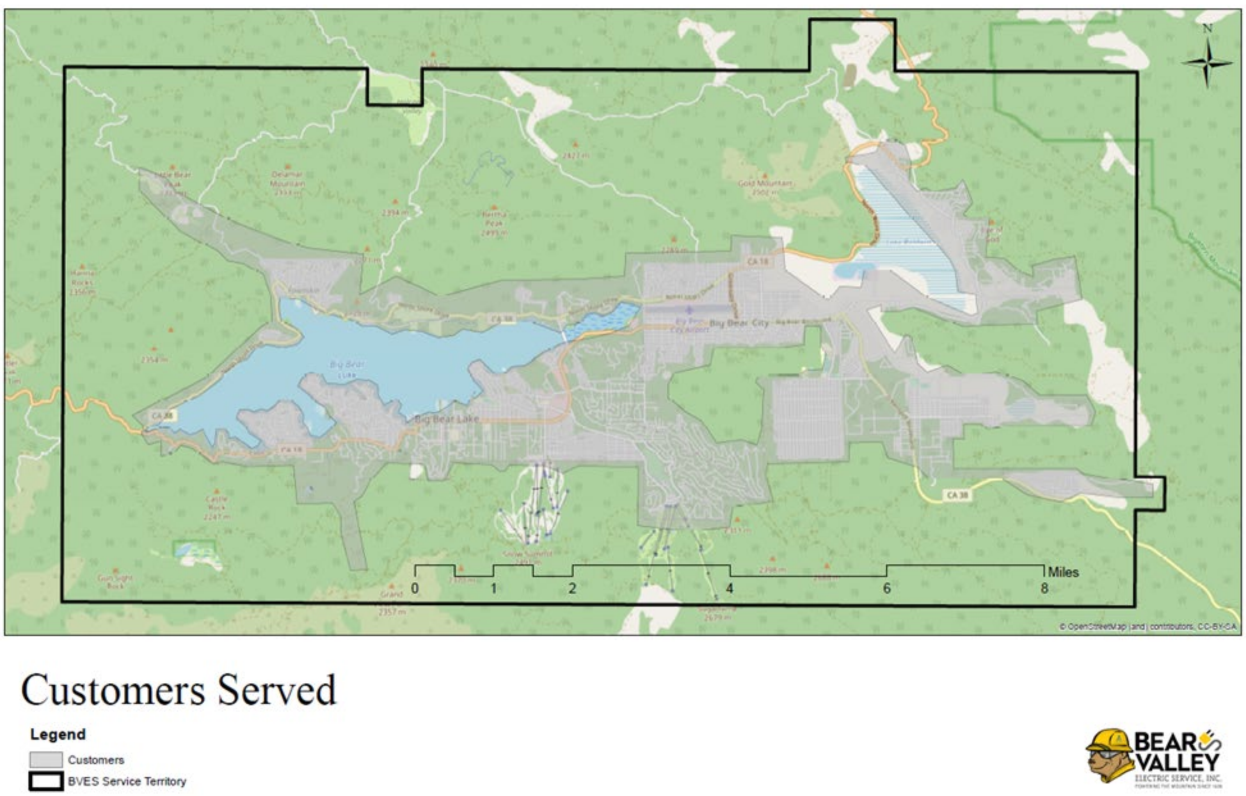



**Figure 5-1 Service Territory and Customers Served**

**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 |

| Type of Equipment | HFTD | Non-HFTD | Total |
|---|---|---|---|
| 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, east wood 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, curl leaf mountain-mahogany, incense-cedar, Jeffrey pine, ponderosa pine, limber pine, lodgepole pine, mixed conifer, mixed subalpine forest, mountain juniper, single leaf 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.

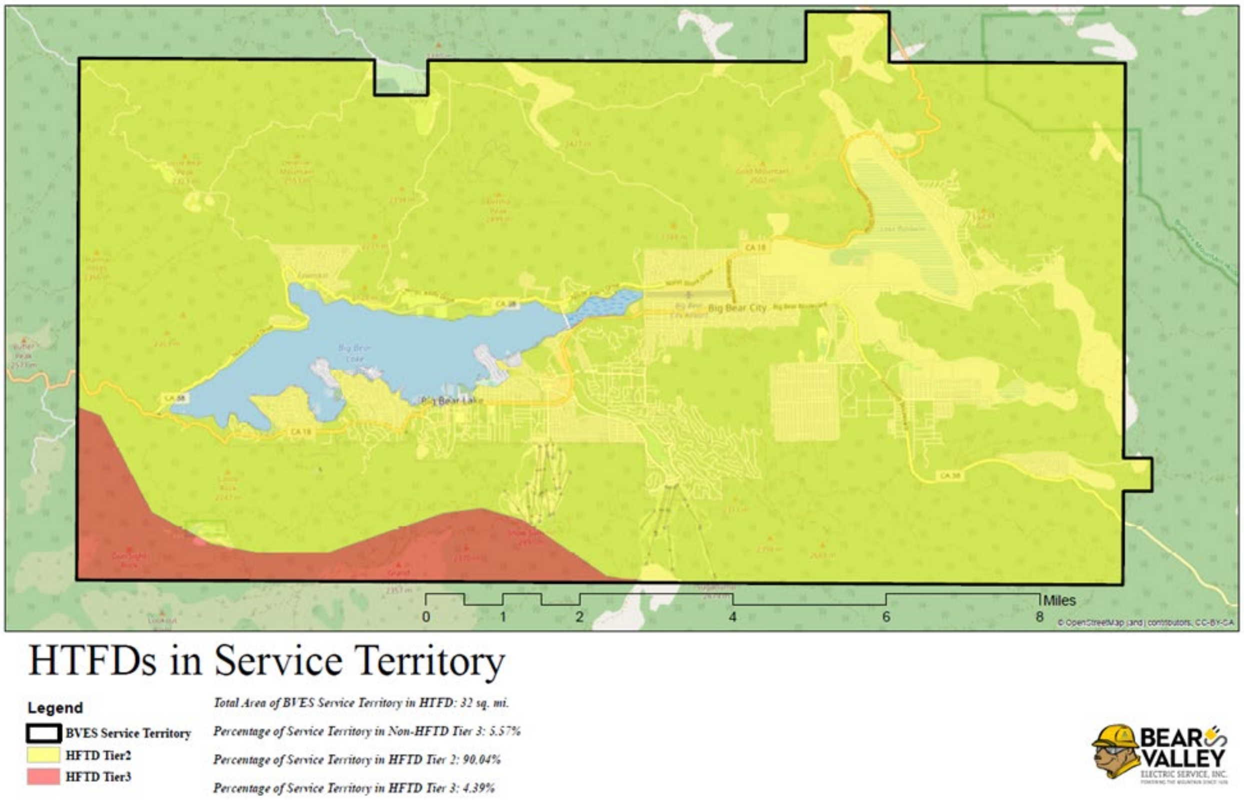



**Figure 5-2 HFTD Tier Breakdown for the Service Territory**

**Table 5-5 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:*

- *Average temperatures throughout the year*

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

- *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.*

The Bear Valley service territory's mean annual temperature is about 40° to 50° Fahrenheit, and its mean annual precipitation is about 30 to 40 inches. Much of the precipitation falls in the form of snow. The mean freeze-free period is about 150 to 200 days.

Bear Valley prepared the following three graphs to provide greater detail into its average temperature, the extreme temperatures and when they occur, and average precipitation. Figure 5-3 provides monthly average rainfall, average high, and average low temperature for the last 40 years. Figure 5-4 provides the maximum high temperature and when said temperature occurs along with the trend line for maximum high temperature over the last 40 years. Finally, Figure 5-5 provides minimum low temperatures and when such temperatures occur along with the trend line for minimum low temperature over the last 40 years.

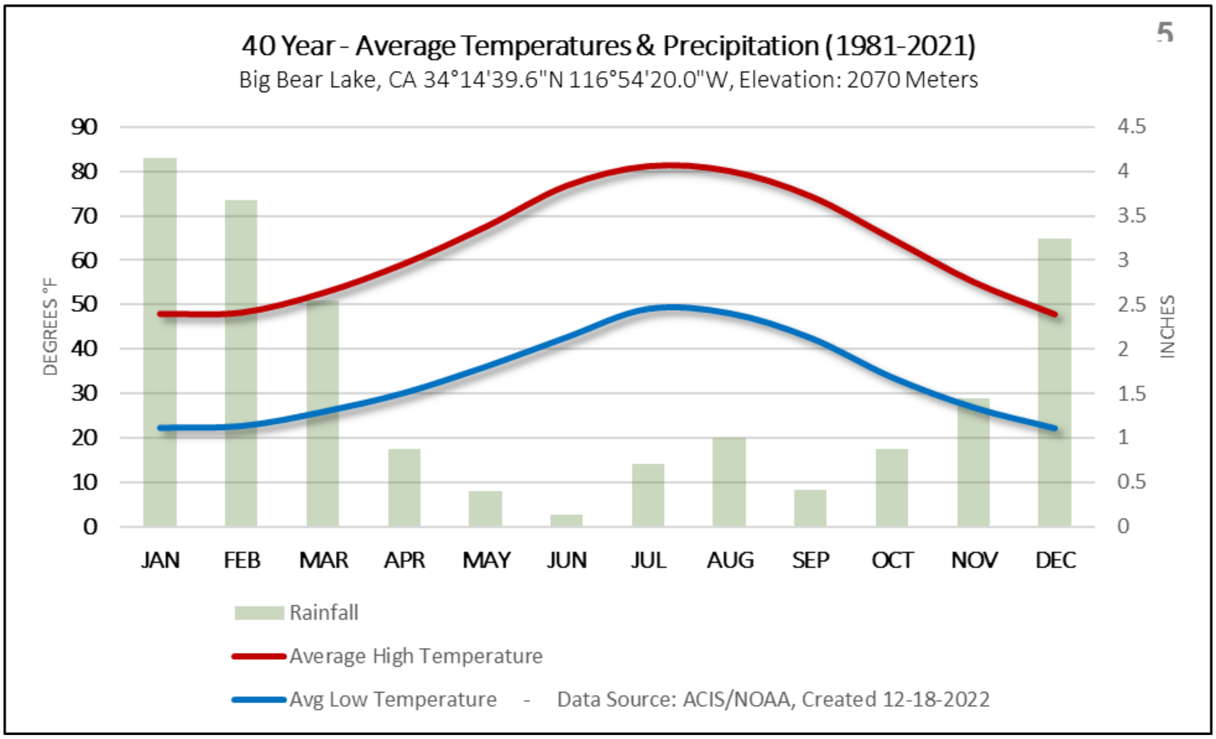



**Figure 5-3 Annual Mean Climatology for the Electrical Corporation's Service Territory**

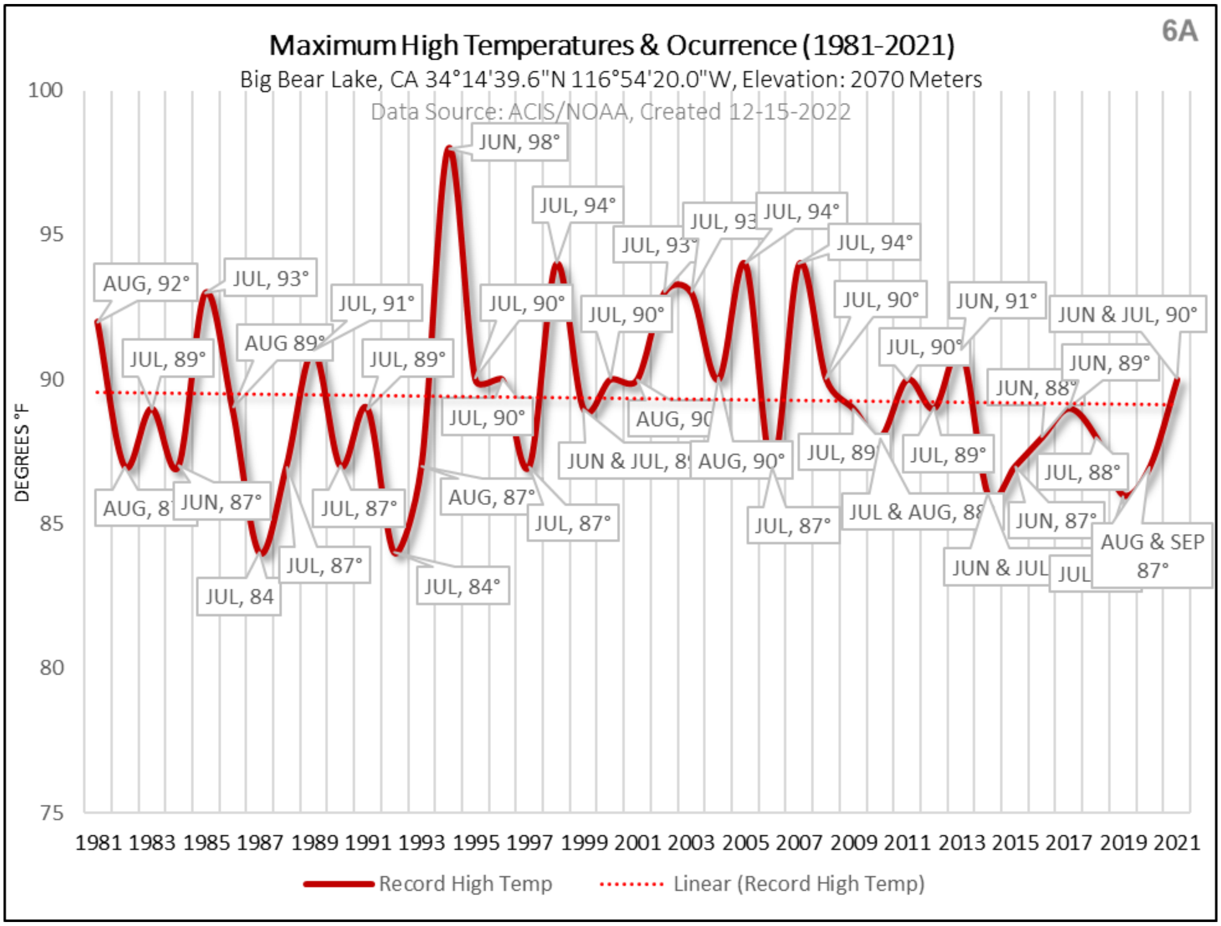



**Figure 5-4 Annual Maximum Temperature and Occurrence for the Electrical Corporation's Service Territory**

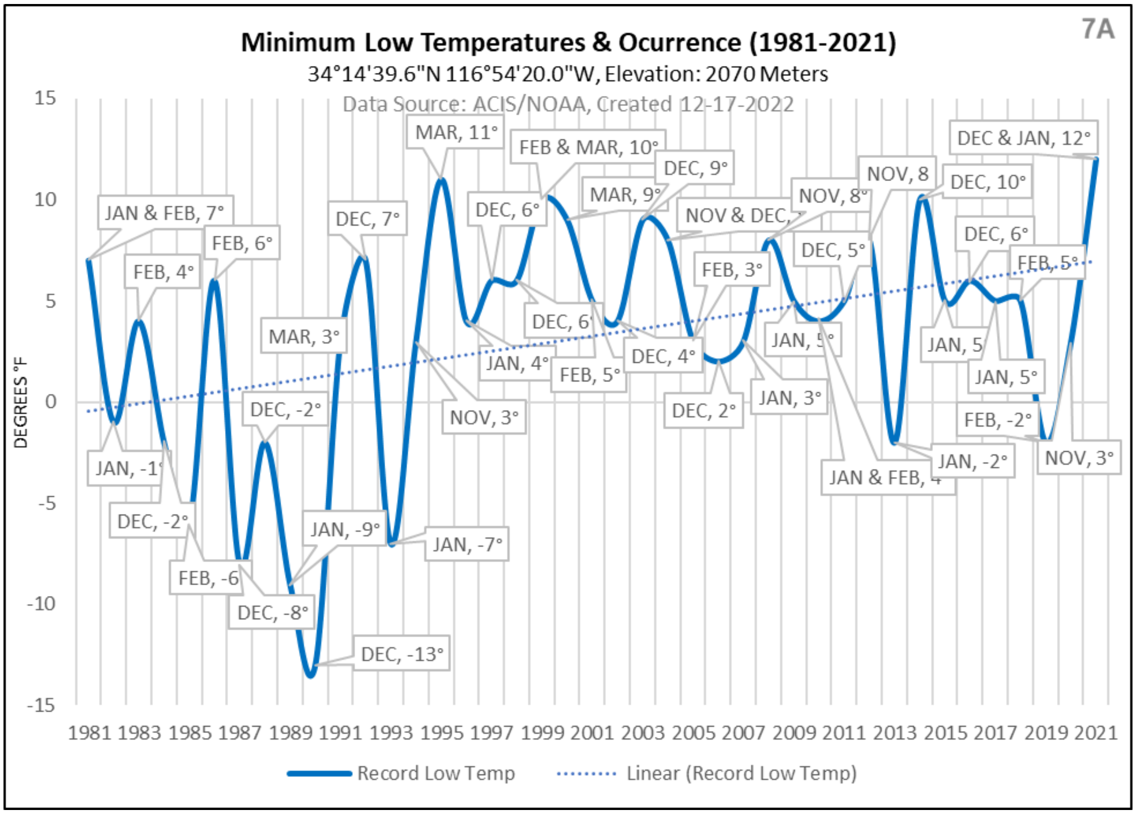



**Figure 5-5 Annual Minimum Temperature and Occurrence for the Electrical Corporation's Service Territory**

### *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.

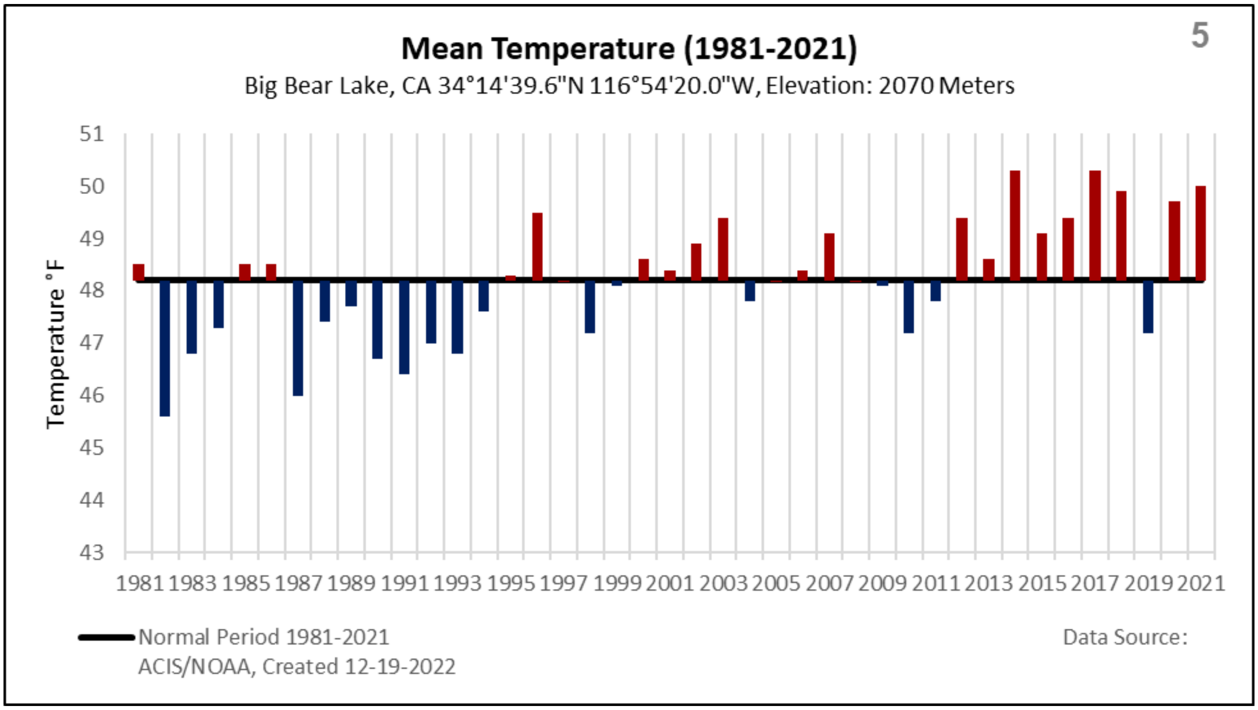



**Figure 5-6 Mean Annual Temperature for Service Territory, 1900s–2020s**

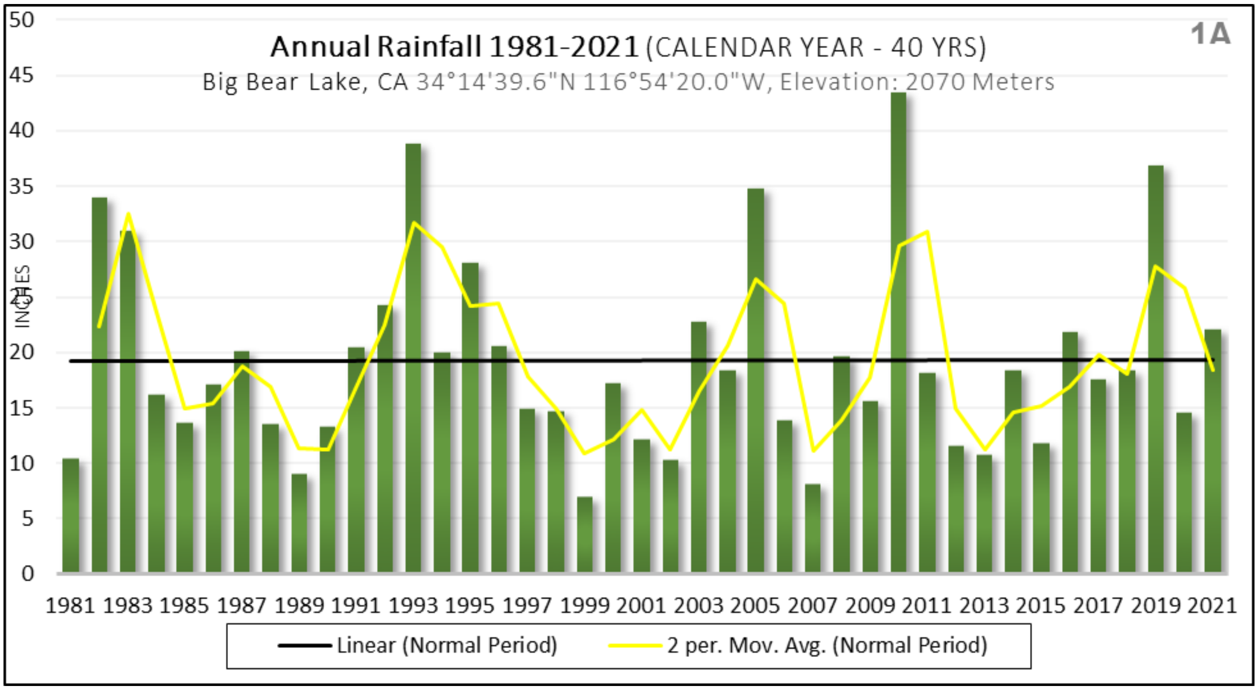



**Figure 5-7 Mean Annual Precipitation for Service Territory, 1900s–2020s**

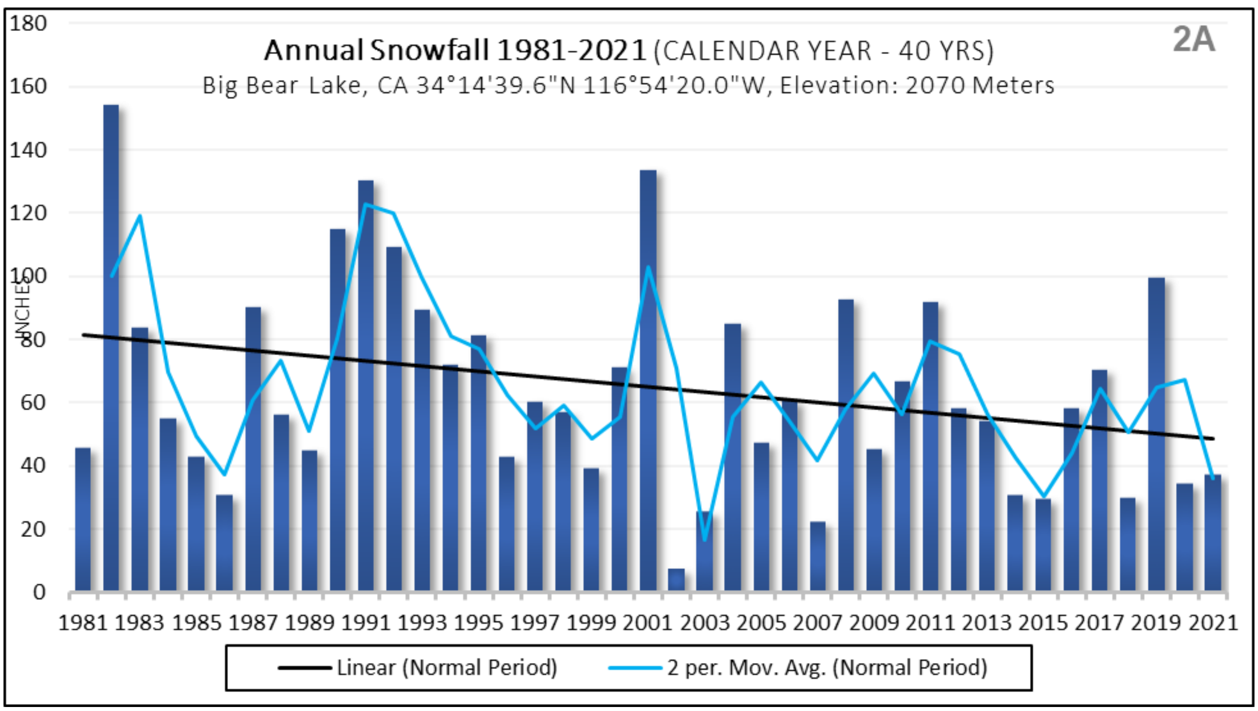



**Figure 5-8 Mean Annual Precipitation for Service Territory, 1900s–2020s**

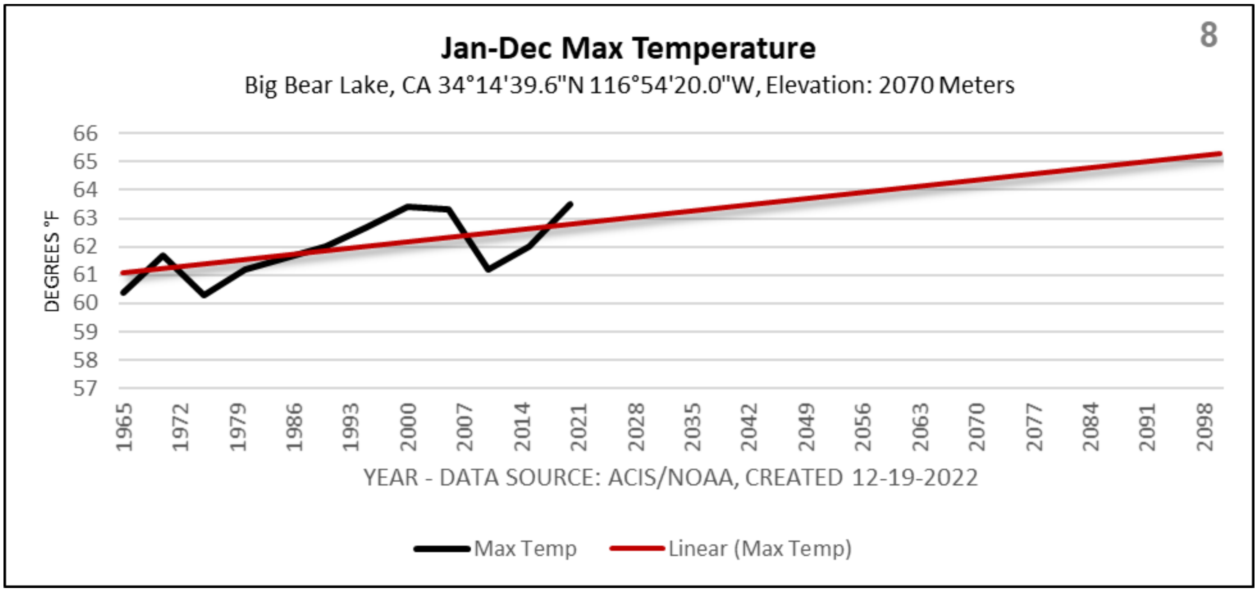



**Figure 5-9 Projected Change in Maximum Temperature (Daytime Highs) Through 2100 for the Service Territory**

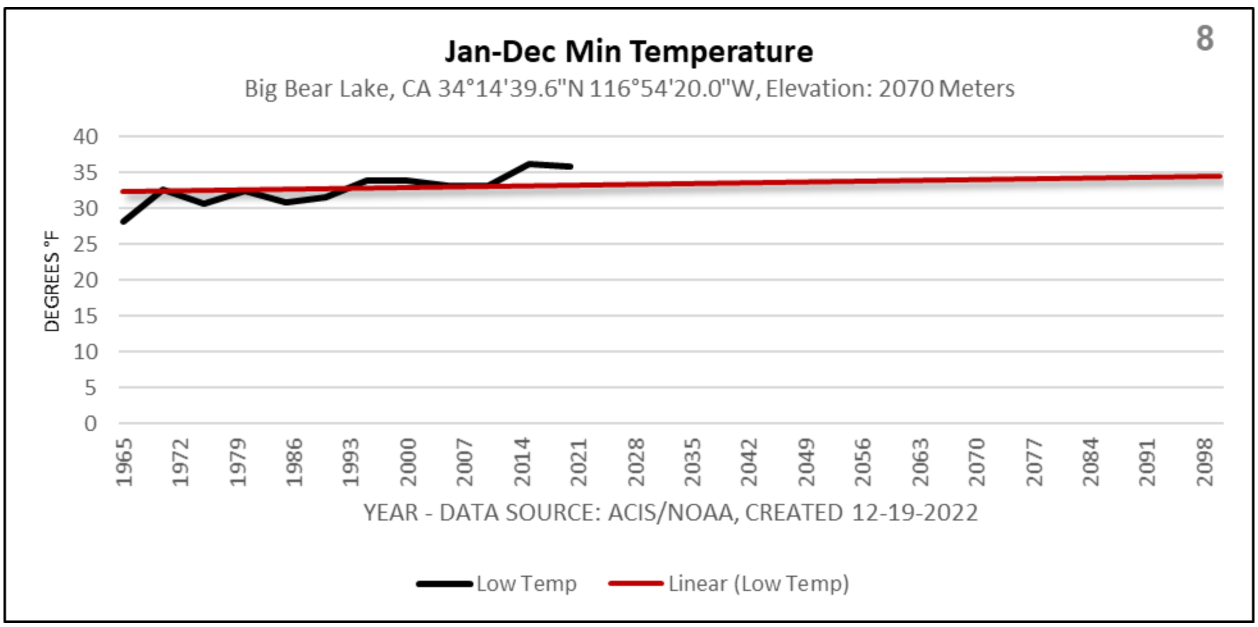



**Figure 5-10 Projected Change in Minimum Temperature (Nighttime Lows) Through 2100 for the Service Territory**

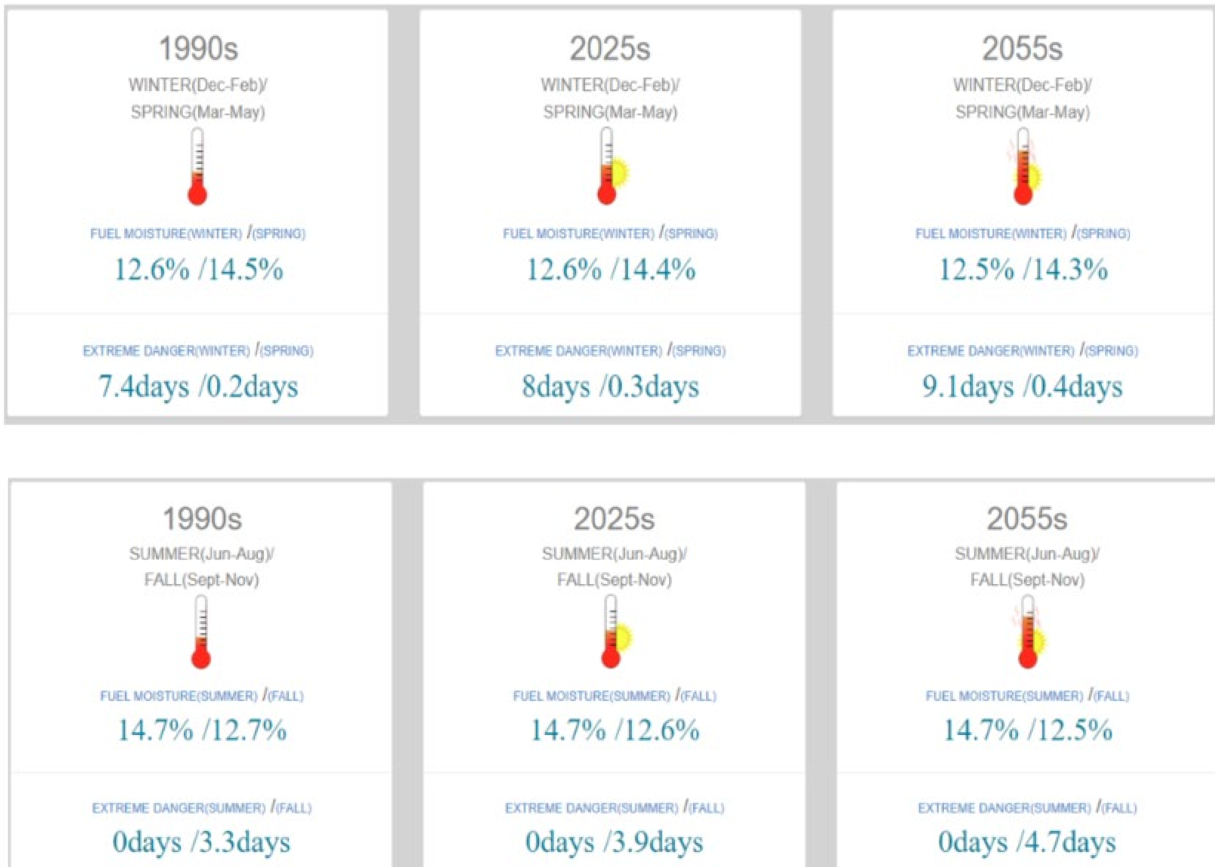



**Figure 5-11. Projected Changes in Average Fuel Moisture and Average Number of Days of Extreme Fire Danger for Winter/Spring and Summer/Fall Periods for the Service Territory Based on Global Climate Model Outputs**

### 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 customers 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 re-evaluate 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.

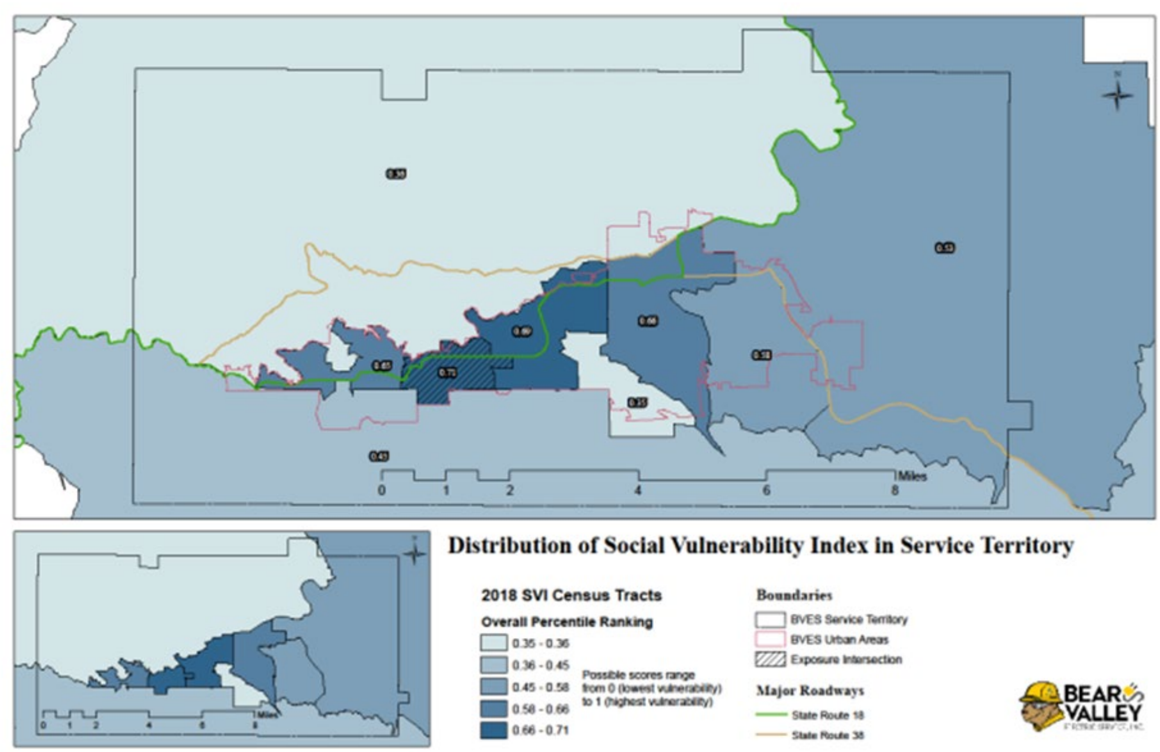



**Figure 5-12 SVI Overlay of Service Territory**

### *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 *(Tracking ID: ST_1)*

*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 Environmental Protection Agency (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.*

In this section, BVES provides an overview of its approach to define and analyze wildfire and PSPS risk. The risk analyses, which results in risk assessments, inform mitigation strategy, prioritization, selection, and scoping as described in Section 7.

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 due to gaps in its modeling capabilities. To rectify this, BVES is establishing a path to comply with all the guidelines of this section. 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 all designated as Tier 2, with a small section of 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. BVES expects to be mostly, if not fully compliant with this section's guidance in its 2024 WMP Update.

## 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)*

BVES maintains a risk mitigation strategy to prioritize the most cost and 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. The following figure provides an overview of BVES's overall risk assessment process.

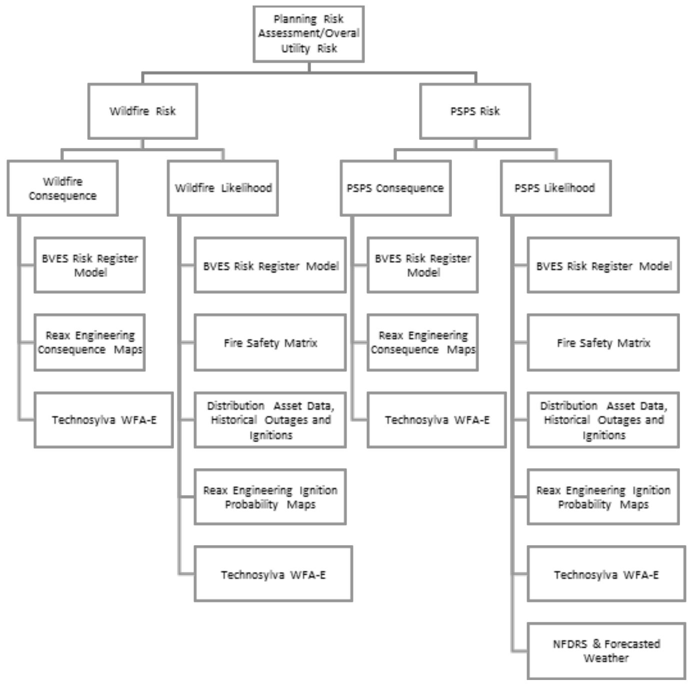



**Figure 6-1 Risk Assessment Component Hierarchy**

As BVES is moving to implement additional modeling capability, BVES expects the overall risk assessment process by the 2024 WMP Update to reflect the figure below:

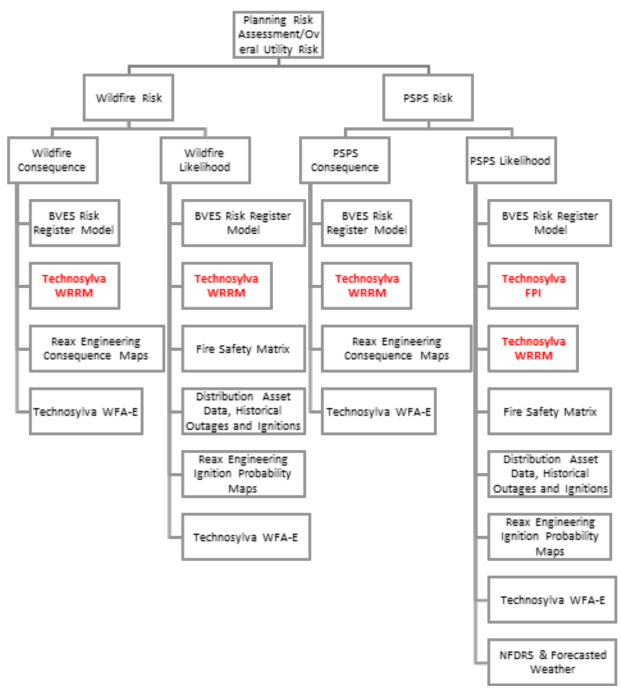



**Figure 6-2 Future State Risk Assessment Component Hierarchy**

Currently, BVES evaluates enterprise risk in accordance with Risk-Based Decision-Making Framework, this aligns with the safety model approach for Small and Multi-Jurisdictional Utilities (SMJU) provided in CPUC D. 19-04-020 of April 25, 2019. This approach to risk management includes the basic tenets of the International Standardization Organization's "Risk Management – Principles and Guidelines" ("ISO 31000"). Specifically, the process utilizes the Cycle Ten-Step Approach to perform the risk analysis. The figure below summarizes the Cycle Ten-Step Approach.

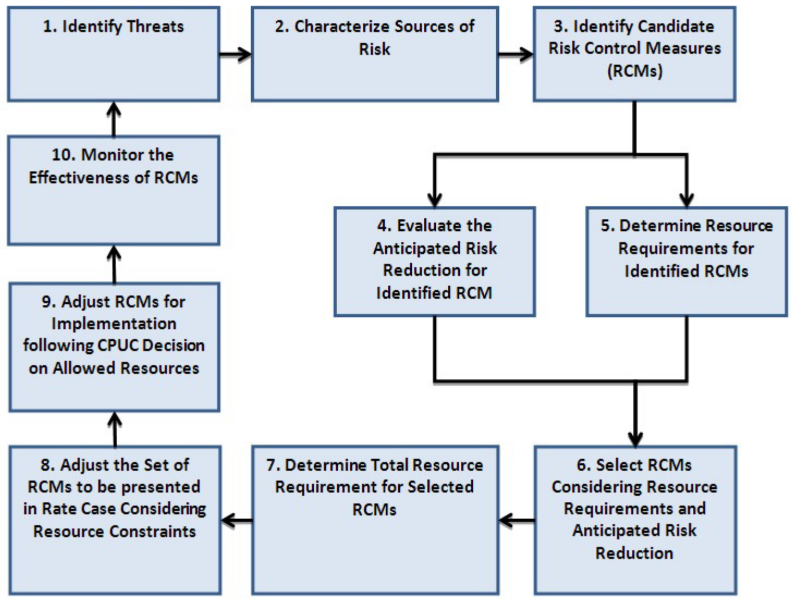



**Figure 6-3 Cycle Ten-Step Approach**

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

- Wildfire – Threats to 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:

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

The Risk Register Model quantifies mitigation projects and programs by the risk benefit and 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 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.

While the Risk Register Model provides overall system risk benefit analysis, it does not provide specific location risk benefit. This limits its value in prioritizing wildfire and PSPS mitigation work in the system. To address this issue, BVES developed the Fire Safety Circuit Matrix, which aims to characterize all BVES distribution circuits in groups of High, Moderate, and Low wildfire risk and then prioritize the circuits within each wildfire risk group. The matrix data uses a balanced scorecard approach, and its 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.

BVES uses the Fire Safety Circuit Matrix as a “living document” as mitigations are implemented. BVES re-evaluates the scores, incorporating any new mitigations, for Wildfire Risk Group, Priority, and Mitigation Weight at least every six months. Additionally, the Fire Safety Circuit Matrix is used to gauge progress and set 3- and 10-year targets for wildfire mitigation score reductions and associated wildfire ignition risk reduction.

BVES enhanced its ignition risk mapping methodology with the completion of several ignition probability and consequence models in 2021 by contracting with REAX Engineering (REAX). REAX provided BVES ignition probability maps along each point of its overhead distribution and sub-transmission system. REAX also developed consequence maps for each point of its overhead distribution and sub-transmission system. The consequence maps were developed for wildfire size (acres burned) and number of structures impacted. REAX then performed the same analysis, projected out to 2050, to provide insight on the impact of long-term climate change. While these maps are very useful in understanding the wildfire risk along the BVES overhead distribution and sub-transmission system, they are static; therefore, BVES sought to move to more dynamic models.

BVES contracted Technosylva to support the Risk Mapping Program to further improve situational awareness. Better understanding of the risk environment should improve BVES’s resource allocation. This effort leverages Technosylva’s Wildfire Analyst Enterprise (WFA-E) software capabilities and solutions implemented across California for other electric utility companies.

Technosylva’s 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 reanalysis 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, are 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.

Wildfire behavior modeling and risk analysis is applied 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 equally, 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 consequences 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.

BVES is also implementing Technosylva's WRRM, which uses historical climatology (weather & fuel moisture data) as key input weather scenarios (~ 30 year and 2 km hourly reanalysis data), to improve its asset risk analysis. The model produces risk metrics by running fire spread simulations for each weather scenario territory wide. The outputs can then be aggregated based on percentile and assigned to assets. The model uses historical or predicted fuels data (*e.g.,* 2030) and utilizes hundreds of millions of fire-spread simulations across customer service territory. The WRRM 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 Safety Circuit Matrix to 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. BVES will use the WRRM to help plan and prioritize initiatives 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.

### 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 |
|---|---|---|---|---|---|---|
| R1 | Overall Utility Risk | Wind Load Condition 1, Wind Load Condition 2, Weather Condition 2, Vegetation Condition 1, Vegetation Condition 3 | Combination of Wildfire Risk and PSPS Risk | BVES Risk Register Model (SMJU Risk-Based Decision Making) | Overall wildfire and PSPS risk | Risk Unit (Specific to Model) |
| R2 | Ignition Risk | Wind Load Condition 3, Weather Condition 2, Vegetation Condition 1, Vegetation Condition 3 | Product of Ignition Likelihood and Wildfire Consequence | Technosylva WFA and WRRM[2] | Wildfire Risk for Circuit Segment | Risk Unit (Specific to Model) |
| R3 | PSPS Risk | Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1 | Product of PSPS Likelihood and PSPS Consequence | Technosylva WFA and FPI[3] | PSPS Risk per Circuit Segment | Risk Unit (Specific to Model) |

[2] BVES expects to fully implement the Wildfire Risk Reduction Model (WRRM) for its 2024 WMP Update.
[3] BVES expects to implement a Fire Potential Index (FPI) by the end of 2023.

| ID | Risk Component | Design Scenario(s) | Key Inputs | Source of Inputs (Data and/or Models) | Key Outputs | Units |
|---|---|---|---|---|---|---|
| LI | Ignition Likelihood | Wind Load Condition 3, Weather Condition 2, Vegetation Condition 1, Vegetation Condition 3 | Technosylva<br>Database<br>BVES GIS Asset Map | Technosylva WFA and WRRM | Ignition Likelihood per Circuit Segment | Ignition Likelihood Unit (Specific to Model) |
| L1 | Wildfire Likelihood | Wind Load Condition 3, Weather Condition 2, Vegetation Condition 1, Vegetation Condition 3 | Technosylva<br>Database<br>BVES GIS Asset Map | Technosylva WFA | Wildfire Likelihood per Circuit Segment | Wildfire Likelihood Unit (Specific to Model) |
| C1 | Wildfire Consequence | Wind Load Condition 3, Weather Condition 2, Vegetation Condition 1, Vegetation Condition 3 | Technosylva<br>Database<br>(Population, buildings, acres burned) | Technosylva WFA | Wildfire Consequence per Circuit Segment | Wildfire Consequence Unit (Specific to Model) |
| L2 | PSPS Likelihood | Wind Load Condition 2, Weather Condition 1, | Technosylva Database | Technosylva WFA & FPI | PSPS Likelihood per Circuit Segment | Wildfire Likelihood Unit (Specific to Model) |

| ID | Risk Component | Design Scenario(s) | Key Inputs | Source of Inputs (Data and/or Models) | Key Outputs | Units |
|---|---|---|---|---|---|---|
| | | Vegetation Condition 1 | | | | |
| C2 | PSPS Consequence | Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1 | Customer Data | Customer Information System | Customers impacted per circuit | Customers/circuit segment |
| LE | Equipment Ignition Likelihood | Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1 | Under Development Expect to use: Outage database, historical faults/ignitions | Distribution Asset Data, Historical Outages and Ignitions | Ignition Likelihood | Annualized ignition probability of ignition |
| LV | Contact from Vegetation Ignition Likelihood | Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1 | Under Development Expect to use: Outage database, historical faults/ignitions | Distribution Asset Data, Historical Outages and Ignitions | Ignition Likelihood | Annualized ignition probability of ignition |
| LO | Contact by Object Ignition Likelihood | Wind Load Condition 2, Weather Condition 1, Vegetation Condition 1 | Under Development Expect to use: Outage database, historical faults/ignitions | Distribution Asset Data, Historical Outages and Ignitions | Ignition Likelihood | Annualized ignition probability of ignition |

| ID | Risk Component | Design Scenario(s) | Key Inputs | Source of Inputs (Data and/or Models) | Key Outputs | Units |
|---|---|---|---|---|---|---|
| LB | Burn Probability | Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3 | Technosylva Database | Technosylva WFA | 100m x 100m pixel destructive potential classification | Probability Units (Specific to Model) |
| WHI | Wildfire Hazard Intensity | Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3 | Technosylva Database | Technosylva WFA | 100m x 100m pixel destructive potential classification | Intensity Units (Specific to Model) |
| WEP | Wildfire Exposure Potential | Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3 | Technosylva Database | Technosylva WFA NFDRS | 100m x 100m pixel destructive potential classification | Exposure Units (Specific to Model) |
| WV | Wildfire Vulnerability | Wind Load Condition 3, Weather Condition 1, | Customer demographics and AFN population | Customer Information System | AFN population per circuit | Customers/circuit |

| ID | Risk Component | Design Scenario(s) | Key Inputs | Source of Inputs (Data and/or Models) | Key Outputs | Units |
|---|---|---|---|---|---|---|
| | | Vegetation Condition 1, Vegetation Condition 3 | | | | |
| PEP | PSPS Exposure Potential | Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3 | Under Development expect to use:<br>Customer demographics and AFN population<br>Technosylva Database | Under Development | Under Development | Under Development |
| PV | PSPS Vulnerability | Wind Load Condition 3, Weather Condition 1, Vegetation Condition 1, Vegetation Condition 3 | Customer demographics and AFN population | Customer Information System | AFN population per circuit | Customers/circuit |

## 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.*

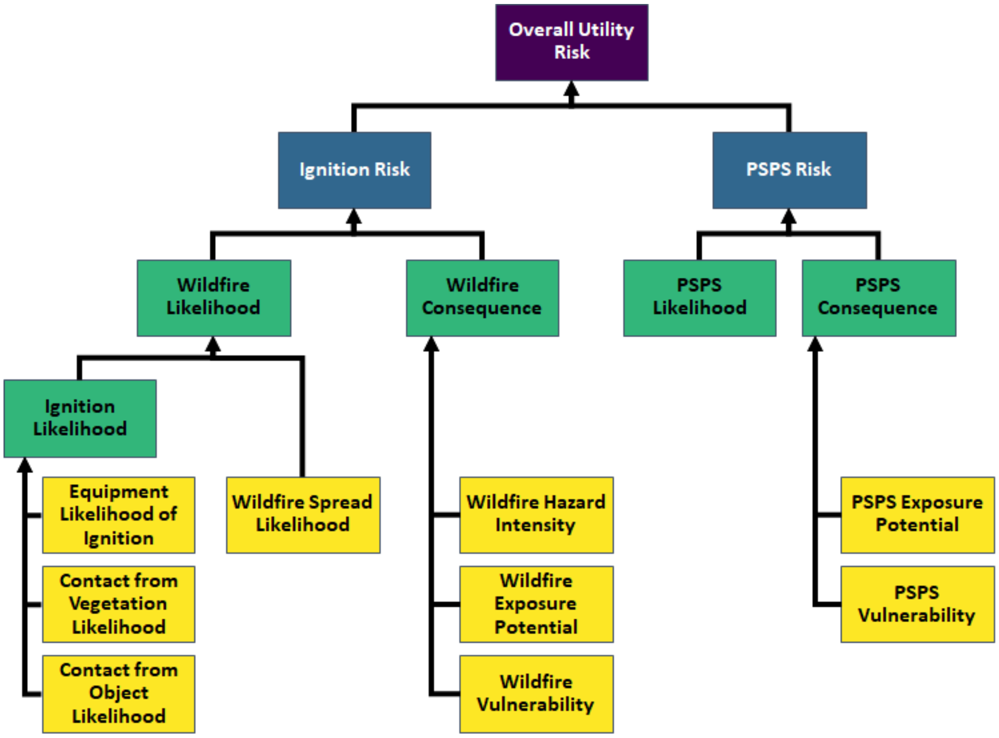



**Figure 6-4 Composition of Overall Utility Risk (purple); Utility-related sources of risk including Ignition and PSPS Risks (blue); Intermediate Risk Components (green); and Fundamental Risk Components (yellow)**

*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.*

Figure 6-1 and Figure 6-2 in Section 6.1.1 illustrate BVES's overall utility risk assessment framework. BVES's overall risk is comprised of the risk stemming from 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 6-4. The following paragraphs define each risk component.

As shown in Figure 6-4 above, 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 become a wildfire, and the potential consequences – considering hazard intensity, exposure potential, and vulnerability –for each community the wildfire 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 inherent risk components that BVES must determine as part of its risk analysis. Intermediate risk components are the likelihood and consequence related to each hazard. Each fundamental or intermediate risk component provides valuable insight in BVES's wildfire and PSPS risk calculations.

There are five intermediate risk components:

1. Ignition likelihood – The total anticipated annualized number of ignitions resulting from electrical corporation-owned assets at each location in the electrical corporation's service territory. This considers probabilistic weather conditions, type and age of equipment, and potential contact of vegetation and other objects with electrical corporation assets. This 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.

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

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

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

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

There are nine fundamental risk components:

1. Equipment ignition likelihood – The likelihood that electrical corporation-owned equipment will cause an ignition either through normal operation or through failure.

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

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

4. Wildfire spread likelihood – The likelihood that a fire with a nearby, but unknown, ignition point will become a wildfire and spread to a location in the service territory based on a probabilistic set of weather profiles, vegetation, and topography.

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

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

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

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

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

BVES has adopted these definitions for its 2023 WMP and for future risk assessments. Table 6-1 describes how these individual hazard risks, intermediate risk components and fundamental risk components are address in BVES current models and future developments. The implementation of Technosylva's WRRM and its modeling software is currently underway. As part of this implementation, BVES will have better 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 through SME evaluation. Bear Valley had previously sought and obtained risk mapping and modeling information that incorporates wildfire risk and ignition potential in the current and projected climate conditions of 2050. This product was static, a snapshot in time. BVES will continue to develop its current models and add additional capability through Technosylva's WFA-E and WRRM until the time BVES is fully able to holistically understand the dynamic ignition and PSPS risk facing BVES.

### 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.*

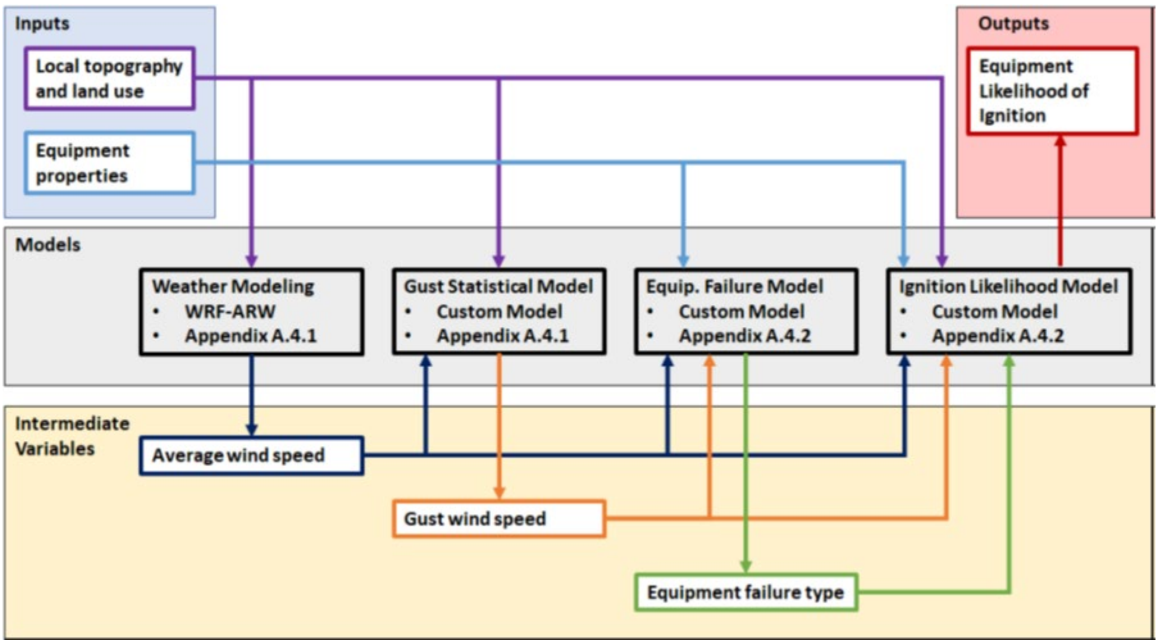



**Figure 6-5 Example Calculation Schematic**

*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.*

BVES calculates Wildfire risk and PSPS risk 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, using its Risk Register Model. The following intermediate risk components are determined by SME evaluation as inputs to the model:

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

Likelihood is determined by SMEs evaluation on a simple 1 to 7 scale with 1 being "occurs once every 100+ years" and 7 being "> 10 times per year".

Consequence is determined by SMEs evaluation on the impact to the following impact weighted components:

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

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

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

This results in risk score which can be plotted on a 7-by 7-logarithmic risk heat map. The following diagram illustrates this process.

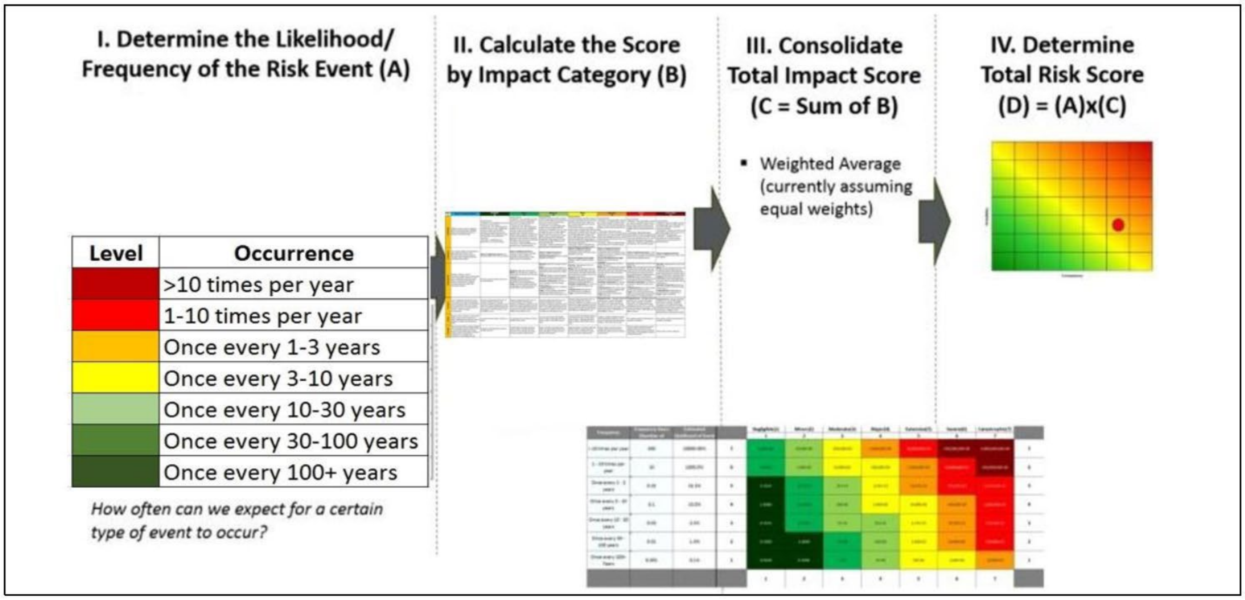



**Figure 6-6 Risk Model Process Diagram**

BVES currently obtains ignition risk as an output from the Technosylva WFA-E model and REAX models.

BVES's risk modeling capability has gaps in that it currently does not specifically calculate the following risk components:

- Equipment ignition likelihood
- Contact from vegetation ignition likelihood
- Contact by object ignition likelihood
- Wildfire spread likelihood – BVES obtains this information via Technosylva's WFA-E model
- Wildfire hazard intensity – BVES obtains this information via Technosylva's WFA-E model
- Wildfire exposure potential
- Wildfire vulnerability
- PSPS exposure potential
- Vulnerability of community to PSPS (PSPS vulnerability)

BVES is working to resolve these gaps. With the implementation of Technosylva's models (WFA-E and WRRM), 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*

As discussed in Section 6.2.2, BVES determines PSPS likelihood by SMEs evaluation on a simple 1 to 7 scale with 1 being “occurs once every 100+ years” and 7 being “> 10 times per year.” This is an input to the Risk Register Model.

BVES now obtains ignition likelihood as calculated output from the Technosylva’s WFA-E model on at least a daily basis. This output is currently used in qualitatively evaluating PSPS likelihood and consequently PSPS risk. BVES is working on developing a Fire Potential Index (FPI) with Technosylva to calculate PSPS risk in a quantitative manner. BVES will be working with Technosylva (and possibly other risk modeling experts) to calculate all likelihood component including the following which are currently not calculated (current gaps in BVES risk modeling):

- 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 this data 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*

As discussed in Section 6.2.2. BVES determines consequence (Wildfire and PSPS) by SMEs evaluation on the impact to the following weighted components:

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

The results of the SME evaluation are then input into the Risk Register Model as described in Section 6.2.2.

BVES is moving to calculate all consequence components via Technosylva's WFA-E and WRRM models in a quantitative manner. Currently, BVES can obtain wildfire consequence as a calculated output from the WFA-E model. The following risk components are not calculated in BVES's risk modeling process (gaps in BVES risk process):

- 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*

Currently, BVES calculates Wildfire risk and PSPS risk as an output of its Risk Register Model as described in Section 6.2.2. BVES obtains Ignition Risk as a calculated output of Technosylva's WFA-E model. BVES has not directly calculated Overall Utility Risk but has qualitatively evaluated such risk based on its calculated Ignition Risk, PSPS Risk, and Wildfire Risk. BVES recognizes that not calculating PSPS risk quantitatively is a gap in BVES's risk process. BVES is working with Technosylva to develop a Fire Potential Index (FPI) so that PSPS risk is calculated. BVES will then work on calculating Overall Utility Risk based on Ignition and PSPS risk.

With the implementation of Technosylva's models (WFA-E and WRRM), 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.*

Key modeling assumptions and limitations to BVES's Risk Register Model include the following:

- Key modeling assumptions are made specifically to each model to represent the physical world and to simplify calculations: The model evaluates each mitigation measure in isolation of other mitigation measures to calculate risk benefit.
- Data standards: Currently BVES utilizes SME evaluation of likelihood and consequence instead of raw data input. SME's evaluate data sources such as outage log, LiDAR surveys, asset hardening, etc. in developing their evaluations. While the data is largely standardized and consistent, the input to the model from the data can fluctuate somewhat due to the inherent subjectivity of the SME's interpretation of the data.
- Consistency of assumptions and limitations in each interconnected model, which must be traced from start to finish, with any discrepancies between models discussed: Assumptions made in the Risk Register Model are consistent with the Fire Safety Circuit Matrix since the Risk Register Model is used to determine mitigations to be implemented and the Fire Safety Circuit Matrix is used to prioritize the mitigations.
- Stability of assumptions in the program: Because the determination of likelihood and consequence is by SME evaluation, stability of the assumptions is susceptible to instability when SMEs change.

Table 6-2 below provides risk modeling assumptions provided by Technosylva with respect to the WFA-E model.

**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. | N/A | N/A | WFA-E |
| Fuels are assumed to be continuous and uniform for the scale of the input (typically between 10-to-30-meter (m) resolution). | N/A | N/A | WFA-E |
| Fire characteristics at a point only depends on the conditions at that point (point-functional model). This means that there are certain non-local phenomena like:<br>• Increase of ROS due to a concave front.<br>• Fire interaction between different parts of the same fire or a different one. | N/A | N/A | WFA-E |
| Fire spread is assumed to be elliptical although there are several variations such as double ellipse, oval, egg-shape, etc. | N/A | N/A | WFA-E |
| Weather is given hourly and is assumed to remain constant during that time. There is no interpolation in time to compute evolution of weather between hours. | N/A | N/A | WFA-E |
| Reliability of weather inputs in the mid-range forecast (2 to 5 days). | N/A | N/A | WFA-E |
| Fire is not coupled with the atmosphere in any way. This may seem like a major limitation in the | N/A | N/A | WFA-E |

| Assumption | Justification | Limitation | Applicable Models |
|---|---|---|---|
| model as wind is a main contribution to fire spread and at present many models (especially physical ones) try to couple wind and fire. The main reasons for us not to consider the coupling is:<br>• It would make it unfeasible to run millions of simulations considering the coupling effect.<br>• Empirical and semi-empirical models have been developed using an average wind speed as an input, so it is not clear that considering more granular wind at the front is advisable. | | | |
| Fire is always assumed to be fully developed. Fire acceleration, flashover, or decay is not considered. | N/A | N/A | WFA-E |
| Atmospheric instability which may have a deep impact on ROS (beer 1991) is not considered in the model. | N/A | N/A | WFA-E |
| Gusts are not considered in the model. | N/A | N/A | WFA-E |
| No interaction between slope and wind other than creating an effective or equivalent wind. This means that fire is assumed to have an elliptical shape no matter the alignment of wind and slope. | N/A | N/A | WFA-E |
| Models have been developed with scares empirical data. The abundance of today's fire data sources, however, is allowing us to better adjust models to observed fire patterns. | N/A | N/A | WFA-E |
| Fuel array description of the vegetation may not perfectly describe fuel characteristics. | N/A | N/A | WFA-E |
| Spotting is only considered in surface fires. | N/A | N/A | WFA-E |

As BVES moves to implement quantitative risk models (Technosylva's WFA-E and WRRM), BVES will regularly monitor and evaluate the scope and validity of modeling assumptions to include as applicable the following monitoring and evaluation categories:

- Adaptation of weather history to current and forecasted climate conditions
- Availability of suppression resources including type, number of resources, and ease of access to incident location
- Height of wind driving fire spread / wind adjustment factor calculation
- General equipment failure rates / wind speed functional dependence for unknown components
- General vegetation contact rates / wind speed functional dependence for unknown species
- Height of electrical equipment in the service territory
- Stability of the atmosphere and resulting calculation of near-surface winds
- Vegetative fuels and fuel models including adaptations based on fuel management activities by other Public Safety Partners

- Combination of risk components / weighting of attributes in alignment with most recent decision issued by the CPUC for inclusion in RAMP filings
- Wind load capacity for electrical equipment in the service territory
- Number, extent, and type of community assets at risk in the service territory
- Proxies for estimating impact on customers and communities in the service territory
- Extent, distribution, and characteristics of vulnerable populations in the service territory

## 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)*

For BVES's Risk Register Model, it considers a reasonable extreme-event scenario for the three primary wildfire risk events, which are:

- Wildfire Public Safety
- Wildfire – Significant Loss of Property
- Loss of Energy Supplies (PSPS)

With the implementation of the Technosylva models (WFA-E and WRRM), BVES will provide greater detail on the design basis scenarios. Much of this information is gapped in BVES's risk modeling process. The following sections detail the gaps and BVES's intentions to close the gaps.

### 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*

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

**Table 6-3 Summary of Design Basis Scenarios**

| Scenario ID | Design Scenario | Purpose | Reference |
|---|---|---|---|
| WL1<br>WL2<br>WC2<br>VC1<br>VC3 | Wind Load Condition 1<br>Wind Load Condition 2<br>Weather Condition 2,<br>Vegetation Condition 1<br>Vegetation Condition 3 | Used in the Risk Register Model and in the application of the WFA-E and WRRM models. | WL1<br>WL2<br>WC2<br>VC1<br>VC3 |

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, considering 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.

**For wind loading on electrical equipment**, BVES will consider at least four statistically relevant design conditions. It will 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 four 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).

**For weather conditions used in calculating fire behavior**, the BVES will use probabilistic scenarios based on a 30-year history of fire weather. This approach will consider a range of wind speeds, directions, and fuel moistures that are representative of historic conditions in the BVES service area. BVES will 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.

BVES is working with Technosylva to develop how it intends to define “fire weather” and “fire season” for the calculations of these probabilistic scenarios.

**For vegetative conditions not including short-term moisture content**, BVES will evaluate design scenarios including the current and forecasted vegetative type and coverage. The conditions BVES will 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.

### 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*

BVES currently analyzes extreme events and highly uncertain scenarios. BVES will be working with Technosylva to develop a long-term extreme-event scenario as indicated in Table 6-4. BVES believes modeling the risk in 2030 is very relevant to ensuring grid hardening efforts are going to be effective at-risk reduction (Ignition Risk and PSPS Risk).

**Table 6-4 Summary of Extreme-Event Scenarios**

| Scenario ID | Extreme-Event Scenario | Purpose |
|---|---|---|
| Not yet assigned | 2030 Climate Conditions (mostly concerned with fuel levels and moisture) | Assess if climate change, as well as any resulting changes in wildfire consequence, may influence BVES's existing grid hardening strategy. |

This is not currently a capability within the Technosylva software program being provided to BVES. However, this capability is going to be available 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.

BVES does not plan on developing the following extreme-event scenarios in the near-term (by 2024):

- 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)

Once BVES has in place its quantitative risk modeling process, it will consider the above extreme-event scenarios; most likely in the 2025 timeframe.

# 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 primarily lies within the HFTD Tier 2 area, with a small portion reaching into a HFTD Tier 3 area along the Radford Line. BVES does not have any self-identified HFRAs that are outside the CPUC’s HFTD. The presence of the HFTD Tier 3 and Tier 2 is included as part of the calculation to determine BVES’s highest risk areas as part of the Fire Safety Circuit Matrix and are incorporated into Technosylva’s WFA-E models as well as the REAX Engineering risk maps of the BVES service territory. The risk by circuit identified by the Fire Safety Circuit Matrix is included below in Table 6-5 in Section 6.4.2. This aligns with the other assessments including those from Technosylva and REAX.

BVES will continue to assess if the HFTD-2 and HFTD-3 boundaries need adjustment in 2023 and beyond.

### *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. The Fire Safety Circuit Matrix currently evaluates all BVES circuits and orders them by overall risk which includes both ignition risk and PSPS risk as well as the mitigation efforts BVES has undertaken to reduce those risks. As stated above, in Section 6.1.1, BVES is working with Technosylva on implementing the WRRM product to replace the use of the Fire Safety Circuit Matrix. The WRRM will include mapped displays of the highest risk circuits in the service territory. Additionally, 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. See Appendix C for additional Fire Risk Maps.

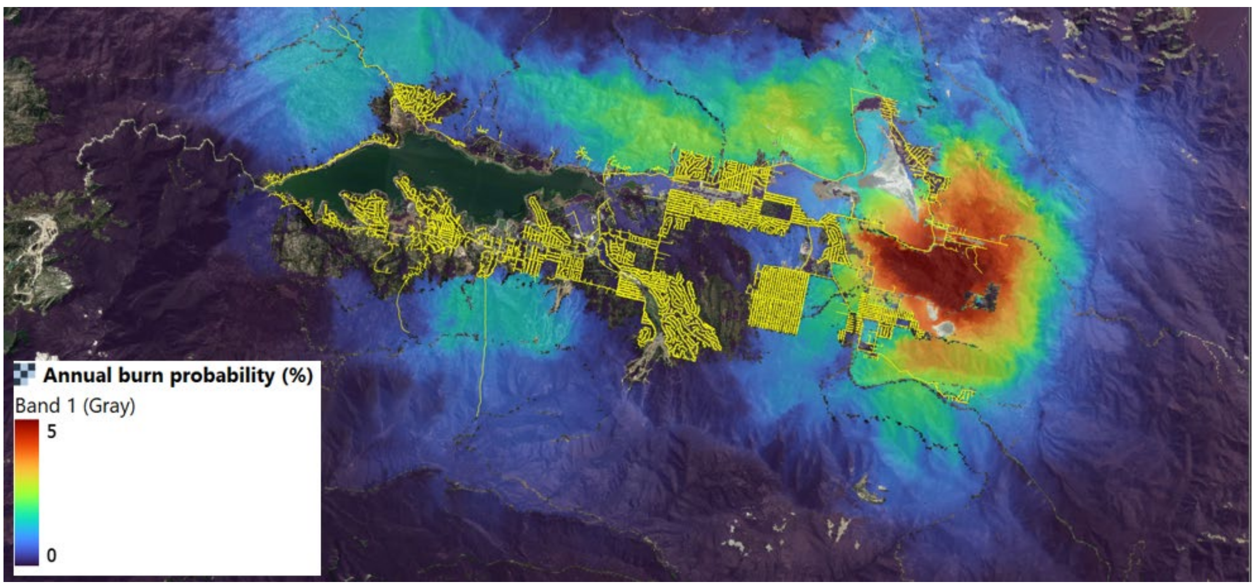



**Figure 6-7 REAX – Risk Level Represented as Annualized Burn Probability**

### *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 the territory is Tier 2 with a small area of Tier 3 along the Radford Line. BVES already identifies and maps its highest risk areas through the Technosylva products, the CPUC and Cal Fire maps, and the Fire Safety Circuit Matrix. If conditions change, due to changes in land use, vegetation density, or climatological factors, BVES will propose such changes to the Commission.

### 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 | Baldwin | 6890.98 | 30 | 60 | 6891 |
| 3 | North Shore (Fawnskin) | 6717.23667 | 30 | 30 | 6717 |
| 4 | Holcomb (Bear City) | 4746.15 | 30 | 30 | 4746 |
| 5 | Goldmine | 4538.8 | 30 | 30 | 4538 |
| 6 | Shay | 3524.49667 | 30 | 60 | 3524 |
| 7 | Clubview | 3225.04 | 30 | 30 | 3225 |
| 8 | Pioneer (Palomino) | 2729.88 | 30 | 30 | 2730 |
| 9 | Sunset | 2373.52 | 30 | 30 | 2374 |
| 10 | Sunrise (Maple) | 1856.69 | 30 | 30 | 1857 |
| 11 | Eagle | 1812.68667 | 30 | 30 | 1813 |
| 12 | Paradise | 1809.54667 | 30 | 30 | 1810 |
| 13 | Lagonita | 1533.14 | 30 | 30 | 1533 |
| 14 | Interlaken | 1485.16 | 30 | 30 | 1485 |
| 15 | Castle Glen (Division) | 1483.32 | 30 | 30 | 1483 |
| 16 | Georgia | 1384.19 | 30 | 30 | 1384 |
| 17 | Garstin | 1366.31 | 30 | 30 | 1366 |
| 18 | Boulder | 882.12 | 30 | 30 | 882 |

*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. The output of this effort is shown above in Table 6-5. BVES further describes the Fire Safety Circuit Matrix, including its data inputs in Section 6.1.1. As you can see this incorporates both ignition risk as well as PSPS risk. While this matrix is the best illustration of which are the top-risk contributing circuits, this represents only part of BVES's risk assessment process. This risk is further understood using BVES's other risk assessment, modeling and mapping tools including the Risk-Based Decision-Making Framework, the Risk Register Model, and the products from Technosylva and REAX procured by Bear Valley. With the implementation of Technosylva's WRRM model, BVES will perform these calculations and expects to have them available in its 2024 WMP Update. As stated above, it is BVES's intent to replace the Fire Safety Circuit Matrix once the WRRM model is fully implemented.

### 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**

| Metric | Non-HFTD | HFTD Tier 2 | HFTD Tier 3 |
|---|---|---|---|
| FPI-OCM/OCM | N/A | N/A | N/A |
| RFW-OCM/OCM | 0 | 0.875 | 0.875 |
| HWW-OCM/OCM | 0 | 8.5 | 8.5 |

BVES 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 and all of BVES's service territory is considered to be one polygon due to its small size. 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*

BVES will implement Technosylva's WFA-E and WRRM models in 2023 and 2024 respectively, which will serve as a risk enterprise system. The WFA-E model was completed in the first quarter of 2023 and is now in use. BVES expects to have the WRRM in place in early 2024. These completions along with their initial implementation will allow BVES to show significant progress in its 2024 WMP Update. Technosylva staff have established controls for updating the models, maintaining configuration control, ensuring the updates are correct (testing and quality assurance process) and implementing the updates. This process is formal and BVES staff is alerted prior to any updates.

BVES does not have an enterprise risk model at this time. BVES will be developing an enterprise risk model that utilizes the various inputs (likelihood and consequence) derived from the WFA-E, WRRM and calculated values (such probability of vegetation contacting lines, etc.). This model will have a formal process to maintain configuration control and update it. These processes will be developed in 2023 as the model is developed.

## 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*

BVES will develop quality assessment and quality control processes and procedures to confirm that the data collected and processed for its risk assessment are accurate and comprehensive as its Risk Assessment Program moves forward. This may include but is not limited to model, sensor, inspection, and risk event data used as part of the electrical corporation's WMP program. BVES will provide an update on this effort as part of its 2024 WMP Update. Independent review will be conducted by a third-party contracted expert.

### 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.*

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

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

REAX provided BVES with Ignition Probability Risk Model / Mapping including a look out to expected 2050 conditions. REAX utilized publicly available utility-ignition data reported to CPUC and OH electrical network filed with WMPs were analyzed to quantify ignition rate (ignitions / 100 pole miles / hour) as a function of wind gust speed, fuel moisture, and temperature. Weather conditions at ignition location & time of ignition determined from gridded meteorological data and normalized by historical values that the entire overhead network "sees". Ignition rate was found to be an exponential function of wind gust speed, fine dead fuel moisture content, and fuel temperature.

Climate conditions for 2021 are derived from the RTMA product from the NOAA / National Centers for Environmental Prediction. This provides hourly gridded (2.5 km) fields of weather conditions from 2011 to current. Future (2050) climate conditions are modeled using a downscaled global climate model developed by UCLA's Department of Atmospheric and Oceanic Sciences. Specifically, the WRF was used to dynamically downscale global climate models (GCMs) from the 6th Coupled Model Intercomparison Project (CMIP6). BVES is using a 10-year block of this data (hourly, 3 km resolution) centered around 2050 in its fire ignition and spread modeling to quantify differences in fire ignition and spread between current (2021) and future (2050) climate conditions.

10-year climatology (2021 and 2050) was used to drive ignition and spread simulations with 1,000,000 years of fires simulated for current and climate-adjusted conditions. The simulation duration varied from 24 hours to one week.

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

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

## 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, BVES relies upon Technosylva for this type of analysis. Technosylva maintains that it meets all the requirements set forth by Energy Safety in this section. BVES recognizes that this is a gap in its capability and BVES intends to develop a better understanding modularization, reanalysis, and version control. BVES will provide additional granularity on this effort in the 2024 WMP Update.

## 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 concise narrative of its proposed improvement plan (maximum of five pages per improvement) summarizing:*

- ***Problem statement*** *– Description of the current state of the problem to be addressed*
- ***Planned Improvement*** *– Discussion of the planned improvement, including any new/novel strategies to be developed and the timeline for their completion*
- ***Anticipated Benefit*** *– 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 |
|---|---|---|---|---|
| Risk assessment methodology | Complete formal implementation and staff training on the WFA-E model to develop proficient model users | Programmatic: Training and process improvements on WFA-E use. | This will help BVES better evaluate their risks both in severity and location and prioritize mitigation efforts to reduce those risks. | Q4 2023 complete process development and staff proficient at use of the model. |
| Risk assessment methodology | Implement use of the WRRM in evaluating asset risks | Programmatic: Training and process improvements on WRRM use. | This will replace the Fire Safety Circuit Matrix to help BVES prioritize | Q1 2023 complete initial delivery.<br>Q3 2023 implement process for evaluating |

| Key Risk Assessment Area | Proposed Improvement | Type of Improvement | Expected Value Added | Timeframe and Key Milestones |
|---|---|---|---|---|
| | | | mitigation initiatives. | WRRM outputs and evaluating asset risk.<br>Q3 2023 Complete staff training |
| Risk presentation | Develop and implement overall risk enterprise system | Technical and programmatic: Develops overall risk enterprise system and processes for control and use of system. Additionally, involves staff training on system. | Produce reliable quantitatively derived wildfire risk, ignition risk, PSPS risk and overall utility risk and display it in a manner that is useful to decision makers. | Q3 2023 Complete development of overall risk enterprise system<br>Q4 2023 Complete process controls and training for overall risk enterprise system |

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 other specific areas for improvement.

**Proposed Improvement Plan**

1. Complete formal implementation and staff training on Technosylva's WFA-E model to develop proficient model users.

- **Problem statement** – The WFA-E model is new to BVES staff, and the model users are not yet proficient in its use or application. Training and user process improvements are needed to maximize the value of the WFA-E product.

- **Planned Improvement** –The goal is to develop proficient model users of the model who understand its limitations and its benefits and can plan and take actionable steps to address risks highlighted by the model. BVES plans to complete the formal implementation and train applicable staff on the WFA-E model. BVES also intends to make user process improvements.

- **Anticipated Benefit** – Properly trained users of the WFA-E model will be better positioned to unlock the most value from the tool. The WFA-E delivers both ignition risk and PSPS risk and severity and helps illuminate potential consequences of fires. This is further enhanced when there is a consistent, repeatable process for users to follow. Improved use of WFA-E by staff will lead to proficiency in operating and understanding the model as an operational tool in assessing ignition risk and PSPS risk on a near-real-time basis. These outputs will lead to actionable efforts both to alleviate real-time operational concerns and to plan and prioritize long-term mitigations. Specifically, better understanding of the tool's capabilities and outputs will lead to planned mitigations to reduce ignition and PSPS risk in those areas most at risk from wildfire and PSPS consequences.

- **Region prioritization (where relevant)** – BVES will analyze its entire service territory through this initiative.

2. Implement use of the WRRM in evaluating asset risks.

- **Problem statement** – BVES's current Fire Safety Circuit Matrix is a crude, static tool that does not allow for complex interactions or provide near-real-time dynamic outputs based on observed or projected conditions.

- **Planned Improvement** – BVES will fully adopt and implement Technosylva's Wildfire Risk Reduction Model (WRRM) in evaluating asset risks and grid hardening and initiative planning for the WMP. In addition to implementation, BVES plans to train its staff on WRRM use and develop process improvements to ensure applicable staff are proficient in operating and understanding the model as a planning tool.

- **Anticipated Benefit** – Adoption of the WRRM as a replacement for the Fire Safety Circuit Matrix will provide BVES with dynamic, granular, near real-time understanding of its service territory. This improvement will allow BVES to better prioritize mitigation initiatives with a probabilistic model to quantitatively calculates ignition and PSPS risk. This will make BVES less dependent on the subjectivity of subject matter experts and manual processes that run the risk of omitting relevant facts. These outputs will lead to actionable efforts both to alleviate real-time operational concerns and to plan and prioritize long-term mitigations. Specifically, better understanding of the tool's capabilities and outputs will lead to planned mitigations to reduce ignition and PSPS risk in those areas most at risk from wildfire and PSPS consequences.

- **Region prioritization (where relevant)** – BVES will analyze its entire service territory through this initiative.

3. Develop and implement overall risk enterprise system

- **Problem statement** – BVES currently does not have a risk enterprise system.

- **Planned Improvement** – BVES intends to develop and implement a comprehensive risk enterprise system. BVES will also develop and implement processes for control and use of the system and a training program for staff to promote utilization and optimization of the system.

- **Anticipated Benefit** – BVES anticipates the benefit to adopting a comprehensive enterprise risk tool is to produce reliable quantitatively derived wildfire risk, ignition risk, PSPS risk and overall utility risk and display it in a manner that is useful to decision makers. This will also help BVES better identify, understand, quantify, and evaluate inherent, emerging, intermediate, and residual risks across its system and to the utility in a manner that is digestible for management. Clear presentation of risks allows the management, staff, and stakeholders to manage risks in a manner that maximizes public safety, reliability, operational efficiency on a cost-effective basis through careful planning organized implementation of risk reduction efforts.

- **Region prioritization (where relevant)** – BVES will analyze its entire service territory through this initiative.

# 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.*

The risk evaluation approach in this WMP is designed to meet a range of industry best practices 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 to meet the objectives stated in Sections 4.1–4.2. Therefore, BVES's general risk evaluation approach consists of the following:

- Identifying risk evaluation criteria based on the balance of various performance goals
- Applying the criteria to monitor the effectiveness of the mitigation initiatives
- Evaluating wildfire and PSPS risks and risk components through a risk-informed decision-making process to develop mitigation initiatives priorities
- Evaluating and prioritizing mitigation initiatives and activities to efficiently reduce risk
- Selecting mitigation initiatives over the WMP cycle based on risk reduction
- Describing selected risk mitigation strategies in the WMP
- Monitoring and re-evaluating mitigation activities to maximize risk benefit and efficiency


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

BVES uses a Risk-Based Decision-Making Framework in accordance with the approach for Small and Multi-Jurisdictional Utilities (SMJU) in CPUC D. 19-04-020. The Risk-Based Decision-Making Framework prioritizes effective strategies for risk reduction. The methodology identifies inherent risk, existing controls, residual risk, and future mitigations after determining the likelihood and impact of wildfire. This is the primary tool for planning WMP initiatives. Figure 7-1, above, provides an overview of the steps.

***Enterprise Risk Mitigation Strategy***

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

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

***<u>Current and Future Locational Prioritization Tools</u>***
BVES's Fire Safety Circuit Matrix characterizes each BVES distribution circuit as high, moderate, and low risk and then prioritize the circuits within each risk group. The matrix data inputs include, inter alia, the number of customers, wood poles, bare wire overhead circuit miles, and tree attachments, which are then compiled and weighted to calculate the wildfire risk mitigation score. Currently, seven circuits are rated high-risk, 12 circuits are rated moderate risk, and seven circuits are rated low risk. BVES uses the Fire Safety Circuit Matrix as a "living document" as mitigations are implemented. BVES re-evaluates the mitigations, wildfire risk group, priority, and mitigation weight at least every six months. Additionally, the Fire Safety Circuit Matrix is used to gauge progress and set 3- and 10-year targets for the reduction of the wildfire mitigation score and associated wildfire ignition risk reduction.

BVES enhanced its ignition risk mapping with REAX Engineering's ignition probability models in 2021 to better predict, quantify, and measure risk drivers under high-risk and climate change related metrological forecasts. The risk maps provide ignition probability, consequence, and risk under current and future conditions to better understand the effects of climate change.

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

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

In 2023, Technosylva delivered the Wildfire Risk Reduction Model (WRRM). This model performs asset risk analysis using historical climatology as inputs and produces risk scenarios by running fire spread simulations for projected weather conditions. The model uses historical or predicted fuels data and runs millions of simulations across the customer service territory showing impact to assets. These outputs will inform future mitigation planning and set the context for daily FireCast asset risk forecasts.

BVES intends to transition from the Fire Safety Circuit Matrix to the WRRM to prioritize its WMP initiatives. The first runs of the WRRM were not completed in time to plan the 2023 WMP initiative work. The WRRM will be used in future WMP Updates. BVES believes that this change will provide a more detailed probabilistic model at the circuit and segment levels.

BVES must also 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.

### 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 – decision maker<br>• PSPS Coordination - informed | • Phone calls as needed<br>• Quarterly public meetings |
| Big Bear Fire Department | Fire Chief | Paul Marconi | • Policy - consulted<br>• Coordinate emergency response - consulted<br>• Wildfire mitigation – decision maker | • Quarterly meetings<br>• As needed phone calls |
| San Bernadino County | Big Bear Lake Representative for County | Paul Marconi | • Policy - consulted<br>• Communication - informed | • Bi-annual meetings |

| Stakeholder | Stakeholder Point of Contact | Electrical Corporation Point of Contacts | Stakeholder Role | Engagement Protocols |
|---|---|---|---|---|
| | Supervisor 3rd District | | | • Phone calls as needed |
| Cal Trans | Transportation Engineer | Tom Chou | • Grid hardening coordination - informed<br>• PSPS coordination - informed<br>• Permitting – decision maker | • Quarterly meetings<br>• Phone calls as needed |
| City of Big Bear Lake | City Manager<br><br>Director of Public Service/City Engineer | Paul Marconi<br><br>Jon Pecchia | • Policy – consulted<br>• Permitting – consulted<br>• Communication – consulted | • Quarterly public meetings<br>• Phone calls as needed |
| Mountaintop San Bernadino US Forrest Service | District Ranger | Jon Pecchia | • Grid hardening coordination – consulted<br>• Vegetation management – consulted<br>• Permitting – decision maker | • Phone calls as needed |

### 7.1.3 Risk-Informed Prioritization

*In making decisions about 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.

BVES developed a list of all its circuits risks that identifies the highest risk circuits for which it will prioritize the application of 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 | 3437 | 89 | 0 | 0 | 0 | 2.82 | 0 | 0.02 |
| Shay | SCE Feed | 3524 | 0.0432 | 6 | 34.5 | 2 | Medium | High | 9582 | 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 | 2015 | 990 | 22 | 6 | 0 | 17.28 | 0.4 | 1.8 |
| North Shore (Fawnskin) | Fawnskin | 6717 | 0.0823 | 3 | 4.16 | 2 | High | High | 1512 | 924 | 0 | 0 | 0 | 15.83 | 0 | 8.09 |
| Erwin Lake | Maltby | 0 | -0.0030 | 26 | 4.16 | 2 | Medium | High | 2574 | 1054 | 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 | 2033 | 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 | 935 | 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 | 86 | 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 | 1095 | 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 | 3.55 |
| Castle Glen (Division) | Division | 1483 | 0.0182 | 15 | 4.16 | 2 | Medium | High | 1216 | 340 | 9 | 2 | 0 | 5.33 | 1.6 | 3.68 |
| Country Club | Division | 640 | 0.0078 | 20 | 4.16 | 2 | Medium | Medium | 596 | 178 | 1 | 0 | 0 | 3.03 | 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 Conditions*

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.

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

***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.

***Feasibility Constraints:***

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

The most significant feasibility constraints facing BVES are jurisdictional considerations, namely permitting, to perform work along the Radford Line which is identified as the highest risk circuit in the Bear Valley service territory. This line resides on USFS land and within their jurisdiction. This has led to permitting delays which have thus far prevented efforts to install covered conductor on this circuit. BVES has, however, made progress with the USFS and expects to complete this effort in 2024.

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

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

### 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 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 is an integrated list of projects with a basic understanding of project need, wildfire risk reduction value, timing, and execution challenges, such as permitting, equipment lag, workforce issues, etc. For each potential project, the risk reduction value and RSE are calculated using the Risk-Based Decision-Making process. For BVES to obtain a reasonable assessment of the risk reduction and RSE for each project, BVES seeks to understand to what degree will the risk reduction work be achieved and, if achievable or partly achievable, at what cost. The following factors are developed and considered by the management team:

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

From the above considerations, management analyzes the cost of the project, the estimated timeline and sequence of the project, and the risk reduction achieved according to the Risk-Based Decision-Making 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*

The BVES process 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. This framework is the Risk-Based Decision-Making Framework in accordance with the safety model approach for Small and Multi-Jurisdictional Utilities (SMJU) provided in CPUC D. 19-04-020. Additionally, BVES is tracking current proceeding activities under R. 20-07-013, for which Safety Model and Assessment Proceeding (S-MAP) enhancements continue to be developed.

### 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 identified in the risk assessment to plan the optimal mix of projects to be included in the WMP (and follow-on updates to the WMP) to deliver maximum risk reduction considering BVES's limited capital and human resources. This process includes re-evaluating multi-year projects that are in progress to determine if they should be continued, discontinued, or revised. The expected outcome of this step is to develop an integrated and prioritized list of WMP projects to be executed in the next and future WMPs. The list of three and ten-year projects can be seen in Table 7-3. 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 Circuit Matrix model described in Section 7.1.1 of this WMP. This provides more granular information at the circuit level. It should be noted that BVES's circuits are short in comparison to many utilities. The longest circuit is 23.9 circuit miles (8 of those circuit miles are underground) and most circuits are less than 10 circuit miles in length. Additionally, the projects are viewed against the risk maps developed by REAX Engineering and Technosylva to determine where the wildfire mitigation greatest risk benefit may be achieved by each project.

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

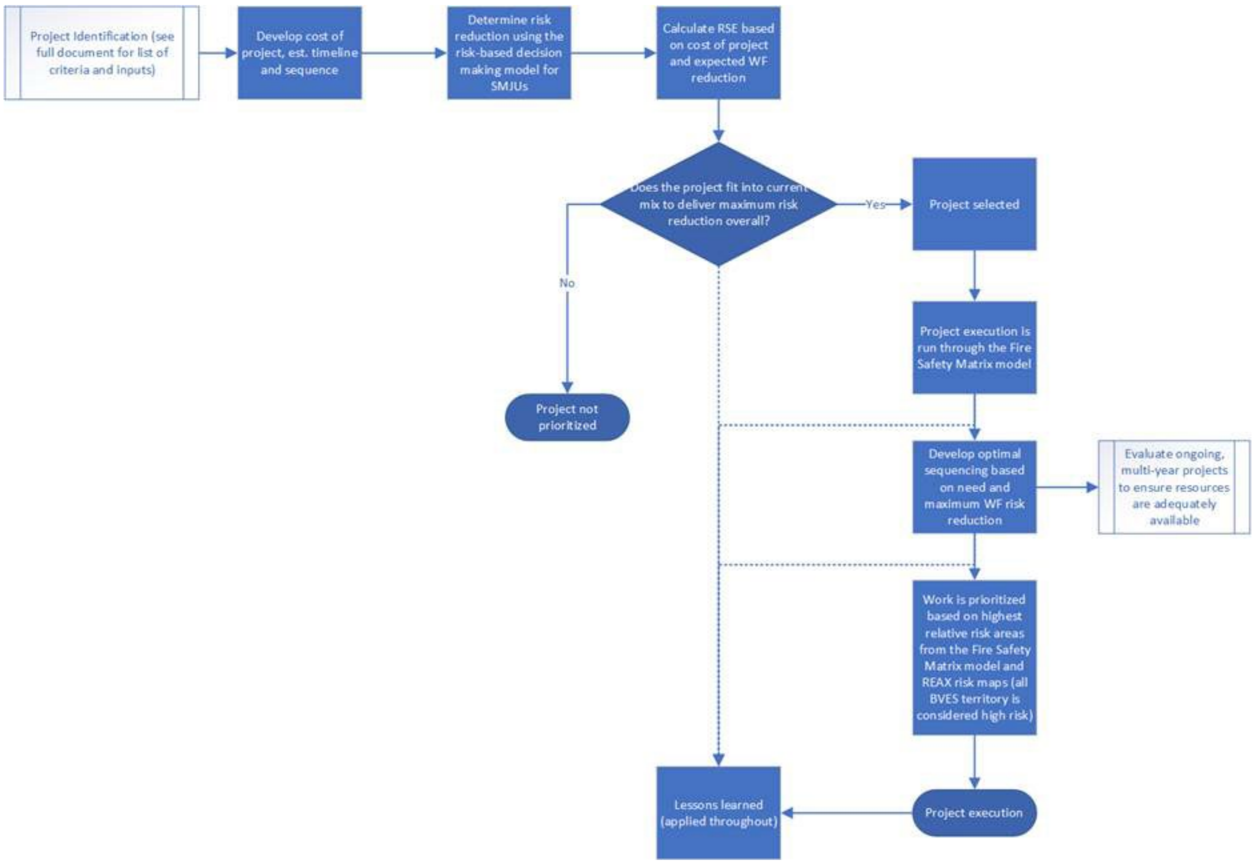



**Figure 7-3 BVES Project Selection Process**

**Resource Optimization**

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

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

This step focuses on allocating resources to 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 Progress Monitoring**

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

**Project Execution Lessons Learned:**

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

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

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

# 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<br>• Assess and remediate all sub-transmission (34 kV) poles<br>• Harden secondary evacuation routes in highest risk areas | • Replace all high and medium risk distribution (4 kV) overhead bare conductors with covered conductors<br>• Assess and remediate all high and medium risk distribution (4 kV) poles<br>• Harden secondary evacuation routes | Section 8.1 |

| WMP Category | Within 3 Years | Within 10 Years | Location in WMP |
|---|---|---|---|
| | • Remove all tree attachments from high-risk areas<br>• On a priority basis, automate substations, switches, field devices, and fuse TripSavers and connect to SCADA<br>• Replace Capacitor Banks and Connect to SCADA<br>• Pursue development and execution of the Bear Valley Solar Energy Project<br>• Pursue development and execution of the Energy Storage Project<br>• Upgrade highest risk substations<br>• 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<br>• Implement robust asset management and inspection enterprise system<br>• Improve quality assurance and quality control program on asset | • Remove all tree attachments from distribution system<br>• Automate remaining substations, switches, field devices, and fuse TripSavers and connect to SCADA<br>• Replace remaining Capacitor Banks and Connect to SCADA<br>• Pursue other renewable generating facility opportunities<br>• Pursue other energy storage project opportunities<br>• Assess emerging technologies aimed at early detection of asset degradation, wire down detection, and other ignition prevention/mitigation technologies<br>• Assess other emerging sub-transmission and distribution inspection techniques | |

| WMP Category | Within 3 Years | Within 10 Years | Location in WMP |
| --- | --- | --- | --- |
| | work and asset inspection | | |
| 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.<br>• Continue to improve program to understand, evaluate, design, and implement wildfire and PSPS risk mitigation strategies, policies, and procedures specific to AFN customers. Evaluate effectiveness of these efforts.<br>• 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 | • 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.<br>• Establish streamlined routine for sharing lessons learned and best practices among peers. | Section 8.5 |

| WMP Category | Within 3 Years | Within 10 Years | Location in WMP |
|---|---|---|---|
| | general plans, community wildfire protection plans, and local multi-hazard mitigation plans. Evaluate effectiveness of these collaborative efforts.<br>• 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. | | |
| Situational Awareness and Forecasting | • Complete online diagnostic pilot program and evaluate effectiveness.<br>• Complete installation of fault indicators (FIs). Evaluate need for additional (FIs).<br>• Evaluate need for additional weather stations.<br>• Evaluate need for additional HD Alert Cameras.<br>• Develop and implement Fire Potential Index.<br>• Improve staff proficiency in utilizing advanced fire threat weather forecasting tools. | • Evaluate effectiveness of installing cameras, infrared detectors, LiDAR instruments, and other technologies on overhead assets to provide remote monitoring. | Section 8.3 |
| Vegetation Management and Inspection | • Maintain enhanced clearance specifications and | • Continue to conduct program to promote vegetation communities that are | Section 8.2 |

| WMP Category | Within 3 Years | Within 10 Years | Location in WMP |
|---|---|---|---|
| | evaluate effectiveness.<br>• Continue to proactively remove/remediate high-risk species.<br>• Continue robust vegetation inspection routine of annual Detailed Inspections, Patrol Inspections, LiDAR surveys, UAV HD Photography, 3rd party Ground Patrols, and Substation Inspections.<br>• Implement robust vegetation management and inspection enterprise system. Ensure all trees within right-of-way tracked in data system.<br>• Improve quality assurance and quality control program on vegetation management inspection and clearance work and asset inspection.<br>• 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. | sustainable, fire-resilient, and compatible with the use of the land as an electrical corporation right-of-way<br>• Evolve vegetation inspection cycles to be risk-based<br>• Evolve vegetation clearance cycles to be risk-based | |

| WMP Category | Within 3 Years | Within 10 Years | Location in WMP |
|---|---|---|---|
| Emergency Preparedness | • Improve staff training on emergency and disaster response plan through a combination of classroom instruction, table-top exercises, and functional drills.<br>• Increase coordination with community stakeholders in emergency response.<br>• Develop robust lines and layers of communications with stakeholders and customers.<br>• Integrate plan to restore service after an outage due to a wildfire or PSPS event.<br>• Establish strong programs, systems, and protocols to support residential and non-residential customers in wildfire emergencies and PSPS events. | • Integrate emergency response plan with stakeholder emergency response plans<br>• Evaluate increased use of social media and technology to improve and streamline communications with stakeholders and customers. | Section 8.4 |

**Project Progress Monitoring**

All projects are monitored during and after their deployment to ensure progress continue on pace, spending aligns with expectations, and to ensure risk mitigation is maximized. Each imitative follows an implementation plan that tracks the schedule, the resources working on the initiative, materials, and other key indicators. BVES management also tracks the schedule and implementation of each mitigation project and initiative closely. Due to the size of the staff and service territory, all projects have full visibility up to the highest level of the utility. Additionally, staff conducts weekly management briefings and management reports to track progress, project needs, challenges, and delays, if any, on every project.

## 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 subsections, 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 7-4 and intends to provide an integrated view of wildfire risk reduction across its service territory over the next 10 years.

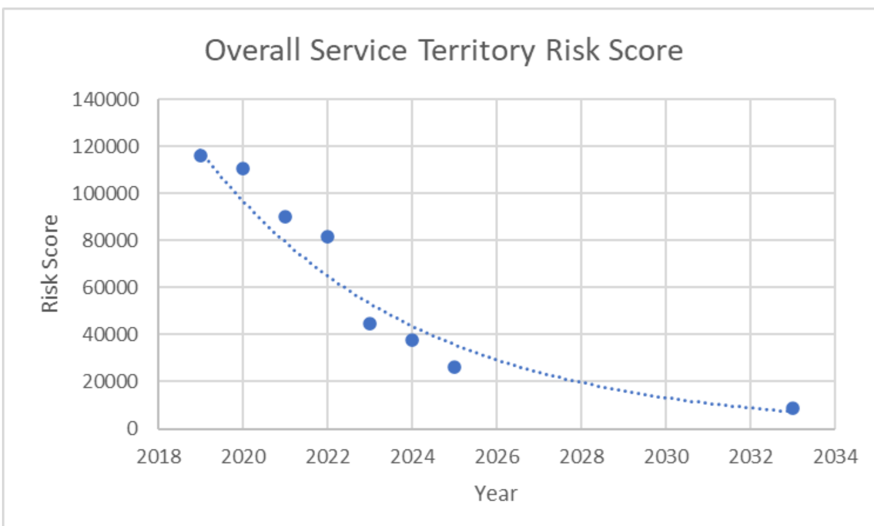



**Figure 7-4 Projected Overall Service Territory Risk Graph**

## BVES Table 7-1 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:

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

### *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 Table 7-4 intends to provide an integrated view of wildfire risk reduction across its service territory from 2023-2025.

**Table 7-4 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 | No Mitigation Initiatives Planned | 522 | No Mitigation Initiatives Planned | 522 |
| Shay | 3524 | Covered Conductor & Pole Assessment and Hardening | 0 | No Mitigation Initiatives Planned | 0 | No Mitigation Initiatives Planned | 0 |
| Baldwin | 6891 | Covered Conductor & Pole Assessment and Hardening | 6891 | Covered Conductor & Pole Assessment and Hardening | 3197 | Covered Conductor & Pole Assessment and Hardening | 345 |
| North Shore | 6717 | No Mitigation Initiatives Planned | 6717 | Covered Conductor & Pole Assessment and Hardening | 6717 | Covered Conductor & Pole Assessment and Hardening | 4585 |

| 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 |
|---|---|---|---|---|---|---|---|
| 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 | No Mitigation Initiatives Planned | 4539 | Covered Conductor & Pole Assessment and Hardening | 3731 | Covered Conductor & Pole Assessment and Hardening | 2721 |
| Holcomb | 4746 | No Mitigation Initiatives Planned | 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 (3-Year Plan)**

| 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) | Covered Conductor Replacement Project, | GO 95 | Completion of planned targeted covered | 31-Dec-25 | 8.1.2.1; pg. 103 |

| 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) |
|---|---|---|---|---|---|
| overhead bare conductors with covered conductors | covered conductor installation GD_1 Radford Line Replacement Project, Covered conductor installation GD_2 | | conductor each year through work orders and visual verification. | | |
| 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 | GO 95 | Completion of planned targeted covered conductor each year through work orders and visual verification. | 31-Dec-25 | 8.1.2.2; pg. 104 |
| Harden secondary evacuation routes in highest risk areas | Evacuation Route Hardening Project, Distribution pole replacements and reinforcements, GD_6 | GO 95<br>GO 165 | Completion of planned targeted evacuation route hardening through work orders and visual verification. | 31-Dec-25 | 8.1.2.3; pg. 105 |
| Remove all tree attachments from high-risk areas | Tree Attachment Removal Project, Other grid topology improvements to minimize risk | PRC 4292 | Completion of planned targeted tree attachments through work orders and sampled | 31-Dec-25 | 8.1.2.10; pg. 116 |

| 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) |
|---|---|---|---|---|---|
| | of ignitions, GD_19 | | visual verification. | | |
| 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 TripSavers Automation, Installation of system automation equipment, GD_15 | GO 95 | Completion of planned targeted projects through work orders, SCADA review. | 31-Dec-25 | 8.1.2.8; pg. 110 |
| Replace Capacitor Banks and Connect to SCADA | Capacitor Bank Upgrade Project, Installation of system automation equipment, GD_14 | GO 95 | Completion of planned targeted capacitor banks through work orders, SCADA review. | 31-Dec-25 | 8.1.2.8; pg. 110 |
| Pursue development and execution of the Bear Valley Solar Energy Project | Bear Valley Solar Energy Project, Microgrids, GD_10 | GO 95 | Work with suppliers and regulatory agencies to develop Solar Energy Project, verified via | 31-Dec-24 | 8.1.2.7; pg. 109 |

| 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) |
|---|---|---|---|---|---|
| | | | work orders, visual verification, and SCADA review. | | |
| Pursue development and execution of the Energy Storage Project | Energy Storage Project, Microgrids, GD_11 | GO 95 | Work with supplier and regulatory agencies to develop Energy Storage Project, verified via work orders, visual verification, | 31-Dec-24 | 8.1.2.7; pg. 109 |
| Upgrade highest risk substations | Partial Safety and Technical Upgrades to Maltby Substation, Other technologies and systems not listed above, GD_22 | GO 95 | Completion of planned targeted substations through work orders, verified via work orders, visual verification, and SCADA review. | 31-Dec-25 | 8.1.2.12; pg. 119 8.1.4.2; pg. 128 |
| Continue robust asset inspection routine of annual Detailed Inspections, Patrol Inspections, LiDAR surveys, UAV HD Photography & Thermography, | Asset inspections, GD-25, GD_26, GD_27, GD_28, GD_29, GD_30, GD_31, GD_32 | GO 95 | Complete planned targeted inspections through work orders. | 31-Dec-25 | 8.1.3.1 – 8.1.3.9; pg. 121-126 |

| 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) |
|---|---|---|---|---|---|
| 3rd party Ground Patrols, Intrusive Pole Testing, and Substation Inspections | | | | | |
| Implement robust asset management and inspection enterprise system | Asset management and inspection enterprise system(s), GD_34 | GO 95 | Provide asset management and inspection reports. | 31-Dec-23 | 8.1.5; pg. 131-134 |
| Improve quality assurance and quality control program on asset work and asset inspection | Quality assurance / quality control, GD-35 | GO 95 | Provide quality assurance and quality control reports. | 31-Dec-23 | 8.1.6; pg. 135-137 |

*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 | Covered Conductor Replacement Project, Covered | GO 95 | Completion of planned targeted covered conductor each year | 31-Dec-32 | Section 8.1.2.1; pg.103 |

| 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) |
|---|---|---|---|---|---|
| conductors with covered conductors | conductor installation GD_1 | | through work orders, visual verification. | | |
| Assess and remediate all high and medium risk distribution (4 kV) poles | Covered Conductor Replacement Project, Covered conductor installation GD_3 | GO 95 | Completion of planned targeted covered conductor each year through work orders, visual verification. | 31-Dec-32 | Section 8.1.2.3; pg. 105 |
| Harden secondary evacuation routes | Evacuation Route Hardening Project, Distribution pole replacements and reinforcements, GD_6 | GO 95 | Planned targeted evacuation route hardening through work orders, visual verification. | 31-Dec-32 | Section 8.1.2.3; pg. 105 |
| Remove all tree attachments from distribution system | Tree Attachment Removal Project, Other grid topology improvements to minimize risk of ignitions, GD_19 | GO 95 | Completion of planned targeted tree attachments through work orders, visual verification. | 31-Dec-32 | 8.1.2.10; pg. 116 |
| 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 | GO 95 | Completion of planned targeted substations through work orders, SCADA review. | 31-Dec-32 | 8.1.2.8; pg. 110 |

| 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) |
|---|---|---|---|---|---|
| | Automation, Installation of system automation equipment, GD_13 Fuse TripSavers Automation, Installation of system automation equipment, GD_15 | | | | |
| Replace remaining Capacitor Banks and Connect to SCADA | Capacitor Bank Upgrade Project, Installation of system automation equipment, GD_14 | GO 95 | Completion of planned targeted capacitor banks through work orders, SCADA review. | 31-Dec-32 | 8.1.2.8; pg. 110 |
| Pursue other renewable generating facility opportunities | Microgrids, GD_10 | GO 95 | Meeting minutes, planning documents, as applicable. | 31-Dec-32 | 8.1.2.7; pg. 109 |
| Pursue other energy storage project opportunities | Microgrids, GD_11 | GO 95 | Meeting minutes, planning documents, as applicable. | 31-Dec-32 | 8.1.2.7; pg. 109 |
| 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 | GO 95 | Assess technologies with vendors and other IOUs to determine if a pilot project is needed. | 31-Dec-32 | 8.1.2.6; pg. 109 |

| 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) |
|---|---|---|---|---|---|
| Assess other emerging sub-transmission and distribution inspection techniques | Asset inspections, GD-25, GD_26, GD_27, GD_28, GD_29, GD_30, GD_31, GD_32 | GO 95 | Assess distribution inspection technologies with vendors and other IOU to determine if new inspections are added | 31-Dec-32 | 8.1.3.1-8.1.3.9; pg. 121-126 |

*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 | 2025 Target | x% Risk Impact 2025 | Method of Verification |
|---|---|---|---|---|---|---|---|---|---|
| Covered conductor installation | GD_1 | Circuit Miles of Line Replaced | 12.9 | *3.62%* | 12.9 | 3.62% | 12.9 | 3.62% | Quantitative |
| Covered conductor installation | GD_2 | Circuit Miles of Line Replaced | 2.7 | 3.62% | 0 | N/A | 0 | N/A | Quantitative |
| Undergrounding of electric lines and/or equipment | GD_3 | Initiate Underground Projects as needed (% of Budget) | 100% | 4.98% | 100% | 4.98% | 100% | 4.98% | Budget Review |
| Distribution pole replacements and reinforcements | GD_4 | Number of Poles Replaced | 200 | 60% | 200 | 60% | 200 | 60% | Quantitative |
| Distribution pole replacements and reinforcements | GD_5 | Number of Poles Replaced | 70 | 88% | 0 | N/A | 0 | N/A | Quantitative |
| Distribution pole replacements and reinforcements | GD_6 | Number of Poles that had Wire Mesh Installed on them | 500 | 12% | 500 | 12% | 500 | 12% | Quantitative |

| 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 |
|---|---|---|---|---|---|---|---|---|---|
| Transmission pole/tower replacements and reinforcements | GD_7 | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Traditional overhead hardening | GD_8 | As Needed Maintenance (% of Budget) | 100% | 4.36% | 100% | 4.36% | 100% | 4.36% | Budget Review |
| Emerging grid hardening technology installations and pilots | GD_9 | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Microgrids | GD_10 | Preform Necessary Project Action | No Action | N/A | File Applicatio n | N/A | No Action | N/A | Project Timeline and Budget |
| Microgrids | GD_11 | Preform Necessary Project Action | No Action | N/A | File Applicatio n & Obtain Permit | N/A | No Action | N/A | Project Timeline and Budget |

| 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 |
|---|---|---|---|---|---|---|---|---|---|
| Installation of system automation equipment | GD_12 | Number of Substations Automated and Connected to SCADA | 3 | 29% | 3 | 29% | 3 | 29% | Quantitative |
| Installation of system automation equipment | GD_13 | Number of Field Switches Automated and Connected to SCADA | 13 | 22% | 10 | 22% | 11 | 22% | Quantitative |
| Installation of system automation equipment | GD_14 | Number of Capacitor Banks Replaced and Connected to SCADA | 6 | 29% | 6 | 29% | 6 | 29% | Quantitative |
| Installation of system automation equipment | GD_15 | Number of Fuse TripSavers Automated and Connected to SCADA | 10 | 29% | 50 | 29% | 50 | 29% | Quantitative |

| 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 |
|---|---|---|---|---|---|---|---|---|---|
| Installation of system automation equipment | GD_16 | Project Milestones for Server Installation | 32% | 84% | 64% | 84% | 100% Project Completion | N/A | Project Timeline and Budget |
| Installation of system automation equipment | GD_17 | Project Milestones for Distribution Management Center | No Action | 72% | 50% Project Completion | 72% | 100% Project Completion | N/A | Project Timeline and Budget |
| Line removals (in HFTD) | GD_18 | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Other grid topology improvements to minimize risk of ignitions | GD_19 | Number of Tree Attachments Removed | 100 | 10% | 100 | 10% | 100 | 10% | Quantitative |
| Other grid topology improvements to mitigate or reduce PSPS events | GD_20 | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Other technologies and systems not listed above | GD_21 | Project Milestones for Natural Engine Upgrades | 32% | 24.8% | 64% | 24.8% | 100% Project Completion | N/A | Project Timeline and Budget |

| 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 |
|---|---|---|---|---|---|---|---|---|---|
| Other technologies and systems not listed above | GD_22 | Project Milestones for Maltby Substation | 32% | 87% | 64% | 87% | 100% Project Completion | N/A | Project Timeline and Budget |
| Other technologies and systems not listed above | GD_23 | Project Milestones for Lake Substation | 32% | 87% | 64% | 87% | 100% Project Completion | N/A | Project Timeline and Budget |
| Other technologies and systems not listed above | GD_24 | Project Milestones for Village Substation | 32% | 87% | 64% | 87% | 100% Project Completion | N/A | Project Timeline and Budget |
| Equipment maintenance and repair | GD_33 | As Needed Maintenance (% of Budget) | 100% | 4.36% | 100% | 4.36% | 100% | 4.36% | Budget Review |
| Asset management and inspection enterprise system(s) | GD_34 | Maintenance of Asset Management System | 100%4.36% | 4.36% | 100% | 4.36% | 100% | 4.36% | Budget Review |
| Quality assurance / quality control | GD_35 | Number of Asset QCs on WMP Work | 20 | 4.36% | 20 | 4.36% | 20 | 4.36% | Quantitative |

| 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 |
|---|---|---|---|---|---|---|---|---|---|
| Open work orders | GD_36 | No discrepancies exceeding GO95 resolution timeframes | All WO resolved within GO 95 Timefram e | N/A | All WO resolved within GO 95 Timefram e | N/A | All WO resolved within GO 95 Timefra me | N/A | WO Log |
| Equipment Settings to Reduce Wildfire Risk | GD_37 | Review and Evaluate System Settings | Review and Evaluate System Settings | 4.36% | Review and Evaluate System Settings | 4.36% | Review and Evaluate System Settings | 4.36% | Meeting Minutes |
| Grid Response Procedures and Notifications | GD_38 | Review and Update Procedure Annually | Finalize Review | 84% | Finalize Review | 84% | Finalize Review | 84% | Version History |
| Personnel Work Procedures and Training in Conditions of Elevated Fire Risk | GD_39 | Review and Update Procedure Annually. Verification of Training Annual | Finalize Review | *3.62%* | Finalize Review | 3.62% | Finalize Review | 3.62% | Version History |

| 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 |
|---|---|---|---|---|---|---|---|---|---|
| Workforce Planning | GD_40 | Verify Appropriate Staffing Levels for Wildfire Related Activities | Staffing Level Verified | 3.62% | Staffing Level Verified | 3.62% | Staffing Level Verified | 3.62% | Meeting Minutes |

**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 | 4.36% | 0 | 40 | 51 | 4.36% | 53 | 4.36% | Quantitative |
| Asset inspections | GD_26 | Circuit Miles Inspected | 0 | 211 | 211 | 4.36% | 0 | 211 | 211 | 4.36% | 211 | 4.36% | Quantitative |
| Asset inspections | GD_27 | Circuit Miles Inspected | 0 | 211 | 211 | 4.36% | 0 | 211 | 211 | 4.36% | 211 | 4.36% | Quantitative |
| Asset inspections | GD_28 | Circuit Miles Inspected | 0 | 211 | 211 | 4.36% | 0 | 211 | 211 | 4.36% | 211 | 4.36% | Quantitative |
| Asset inspections | GD_29 | Circuit Miles Inspected | 0 | 211 | 211 | 4.36% | 0 | 211 | 211 | 4.36% | 211 | 4.36% | Quantitative |
| Asset inspections | GD_30 | Circuit Miles Inspected | 0 | 211 | 211 | 4.36% | 0 | 211 | 211 | 4.36% | 211 | 4.36% | Quantitative |
| Asset inspections | GD_31 | Number of Poles Intrusively Inspected | 0 | 300 | 850 | 4.36% | 0 | 300 | 850 | 4.36% | 850 | 4.36% | Quantitative |

| 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_32 | Number of Substations Inspected | 72 | 108 | 144 | 4.36% | 72 | 108 | 144 | 4.36% | 144 | 4.36% | 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 |

## 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 replaces 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.

*<u>Covered Conductor Project – Radford Line Sub-transmission Project</u>*

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 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.

*<u>34.5kV System</u>*

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

*<u>4kV System</u>*

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.

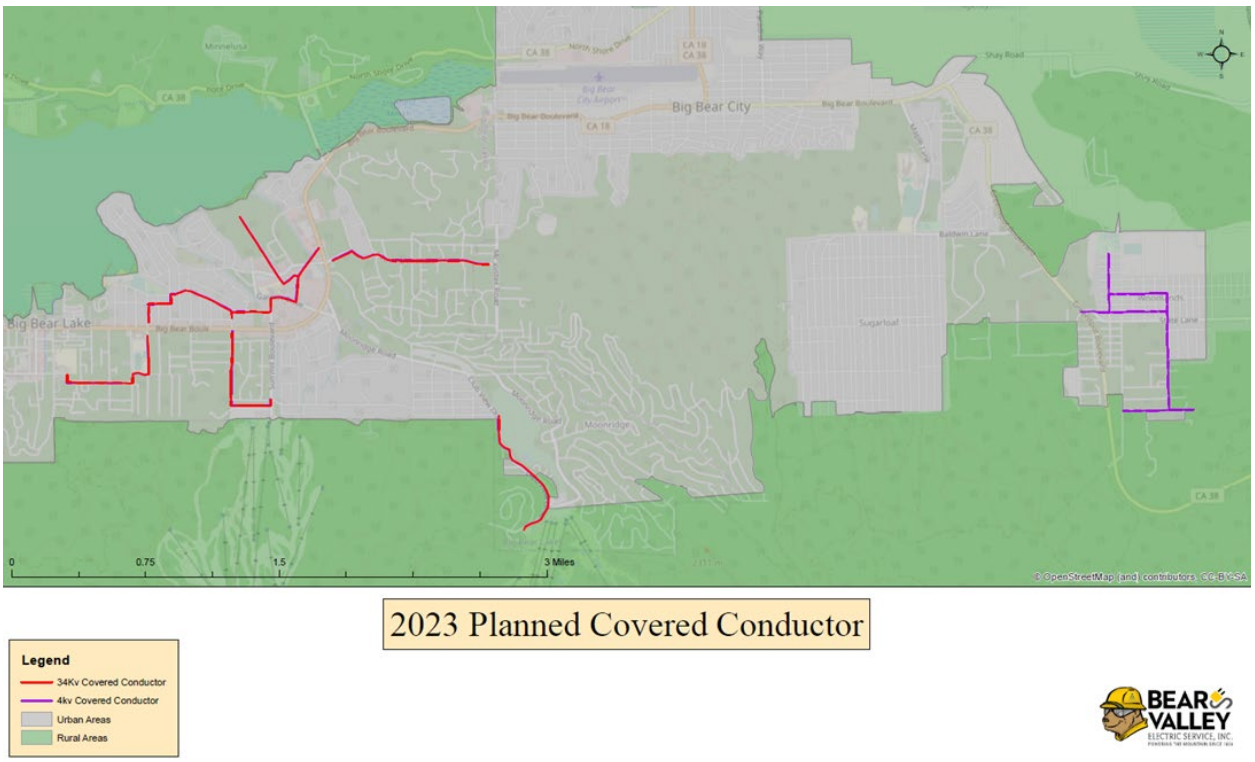



**Figure 8-1 2023 Planned Covered Conductor Installation Location**

### *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.

**<u>Distribution Pole Replacement and Reinforcement – GO 95 Projects (Tracking ID: GD_6)</u>**

*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 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: GD_1 – GD_2)</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:GD_6)**

### 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)*

**Addition and replacement of distribution and sub-transmission components and equipment**

BVES's traditional overhead hardening initiatives consist of replacing bare conductors with insulated 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, as mentioned in Section 8.1.2.1. The replacement program is prioritized based on higher risk circuits to maximize the risk reduction. BVES plans to replace its 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, poles that are not compliant with GO 95 safety factors are identified and remediated appropriately. Depending on the nature and extent of the noncompliance, the remediation will require either repair (e.g., the installation or modification of guy wires) or complete replacement of the pole, including removal and reinstallation of all attachments, all within the time frames required by GO 95. GO 95 is aimed at the safety of personnel, the public, and preserving the reliability of the power grid. Risk is significantly reduced when poles are brought into compliance with laws directed at preserving safety and reliability.

Updates to the Initiatives

BVES will apply any lessons learned throughout the progression of the program. As part of the project, BVES will install utility fiber and use this for future system monitoring efforts (via cameras, infrared sensors, system diagnostics sensors, etc.) and for fast acting switches on the circuit.

Where possible, BVES will look for synergies between initiatives such as covered wire installation and pole loading assessment, infrastructure hardening, and replacement programs to maximize the risk benefit associated with each project.

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

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)*

**Bear Valley Energy Storage Facility (GD_11)**

**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.

**Energy Storage/Solar Energy Project (GD_10)**

**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_14 – 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)<br>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 (GD_12)**

### Overview

The project aims to connect nine substations, three per year in 2023-2025, to Bear Valley's SCADA network 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, Meadow, 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) (GD_13)**

**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 TripSavers Automation (GD_15)**

**Overview**

This initiative is aimed at reducing the risk of ignitions due to conventional fuses and to increase situational awareness of the electric distribution system, rapidly detecting fault conditions, and restoring the fuses remotely through the SCADA system. The Fuse TripSavers 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 switch the devices rapidly and remotely 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 (GD_16)

### 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

## Distribution Management Center Program (GD_17)

### 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.

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

**Switch and Field Device Automation Project. (GD_14)**

**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 (GD_21)**

### 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_22 - 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, reclosers, 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 Asset 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 | N/A |
| Distribution | Detailed Inspection | 5 Years | Ground inspection | GO 165 & GO 95 (Rule 18) | 8.1.3.1 |
| Distribution | Patrol Inspection | Annual | Ground inspection | GO 165 & GO 95 (Rule 18) | 8.1.3.2 |
| Distribution | UAV Thermography Inspection | Annual | Aerial inspection | GO 95 (Rule 18) | 8.1.3.3 |
| Distribution | UAV HD Photography/Videography | Annual | Aerial inspection | GO 165 | 8.1.3.4 |
| Distribution | LiDAR Inspection | Annual | Ground and Aerial inspection | GO 95 (Rule 18) | 8.1.3.5 |
| Distribution | 3rd Party Ground Patrol | Annual | Ground inspection | GO 165 & GO 95 | 8.1.3.6 |
| Distribution | Intrusive Pole Inspection | Per GO 165 | Ground inspection | GO 165 | 8.1.3.7 |
| Substation | Substation Inspection | Monthly | Ground inspection | 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 (Tracking ID: GD_25 - VM_1)*

*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).*

*Process*

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 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 conducts detailed inspections on every circuit is inspected at least every five years.

#### *8.1.3.2 Patrol Inspection Program (Tracking ID: GD_26 - VM_2)*

*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 (Tracking ID: GD_27)*

*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. BVES's entire 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 (Tracking ID: GD_28 – VM_3)*

*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 can slow down the recording so as to note any issues. When a potential issue is identified, they can freeze the video and perform further analysis such as zooming in on the item in question. Discrepancies are then identified, evaluated, recorded, and remediation or further investigation is assigned.

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

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

*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 (Tracking ID: GD_29 – VM_4)*

*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 (Tracking ID: GD_30 – VM_5)*

*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 (Tracking ID: GD_31)*

*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 (Tracking ID: GD_32 – VM_6)*

*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 (Tracking ID: GD_28 – VM_3)*

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 (Tracking ID: GD_8 – GD_14)*

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.

**BVES Table 8-1 Capacitor Replacement List**

| Year | Element Name | Type | Phasing | Upline Source | Upline Feeder | Address | Status |
|---|---|---|---|---|---|---|---|
| 2023 | C12525BV | Capacitor | ABC | Village | Boulder Breaker | 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 | Erwin Lake Circuit | 1048 Willow Ln, Big Bear, CA 92314 | ONLINE |
| 2023 | C6116BV | Capacitor | ABC | Maltby | Erwin Lake 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 (Tracking ID: GD_8 – GD_23)*

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 (Tracking ID: GD_33)*

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 (Tracking ID: GD_1 – GD_2)*

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

- Detailed asset inspections
- 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 includes 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 (Tracking ID: GD_15)*

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

Fuses are inspected as follows:

- Detailed asset inspections
- Patrol 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 (Tracking ID: GD_4 – GD_5 – GD_6)*

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 preventative maintenance to identify poles at risk

### *8.1.4.7 Lightning arrestors (Tracking ID: GD_4 – GD_5 – GD_6 – GD_28 – VM_3)*

BVES installs lightening arrestors that are approved for use in all areas of California in accordance with GO-95. Lightning arrestors are inspected 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 (Tracking ID: GD_12, GD_13, GD_14, GD_15, GD_16, GD_17)*

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 (Tracking ID: GD_4 – GD_5 – GD_6)*

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 (Tracking ID: GD_8)*

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 preventative 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) (Tracking ID: GD_34)

*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. BVES Table 8-2 below highlights the types of data collected and the repository in use by BVES for such data.

**BVES Table 8-2 Detailed Data Information**

| Data Source | Storage Location | Data | Planned Next Steps | Storage Type (Excel, GIS, etc.) | Update Process |
|---|---|---|---|---|---|
| Vegetation Management | Partners & Spreadsheet Database & iRestore (in progress) | Vegetation findings and completed sections | Migration to iRestore (cloud-based) software | Excel, Geo Database, Cloud-based | Manual, mobile phone, and tablet |
| Substation Inspections (GO 174) | Paper-based-database & iRestore (in progress) | Asset inventory, type, and condition | Migration to iRestore (cloud-based) software Oct. 2023 | Binder, Cloud-based | 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 | Will be reviewing the program and improving as needed | Excel, Geo Database | Manual |
| Covered Conductor | Spreadsheet & Geo database | Asset inventory | Continue to update into Geo Database | Excel, Geo Database | Manual |
| Pole Replacement | Spreadsheet & Geo Database | Asset inventory, inspection dates, findings, and condition | Continue to update into Geo Database | Excel, Geo Database | Manual |
| Pole Remediation | Spreadsheet | Asset inventory, inspection dates, findings, and condition | Will be reviewing the program and improving as needed | Excel | Manual |
| Pole Assets | Spreadsheet & Geo Database | Asset inventory, inspection dates, findings, and condition | Continue to update into Geo Database | Excel | Manual |
| Fire Wrap | Spreadsheet & Geo Database | Asset inventory, inspection dates, findings, and condition | Continue to update into Geo Database | Excel, Geo Database | Manual |
| Fuse Replacement | Spreadsheet & Geo Database | Asset inventory, inspection dates, findings and condition | Continue to update into Geo Database | Excel, Geo Database | Manual |

| Data Source | Storage Location | Data | Planned Next Steps | Storage Type (Excel, GIS, etc.) | Update Process |
|---|---|---|---|---|---|
| VM QA/QC Inspections | Web Portal | Vegetation findings and completed sections | Migration to iRestore (Cloud-based) software | Excel | Manual, Via tablet |
| Asset Inspection QA/QC | Spreadsheet | Asset inventory, inspection dates, findings, and condition | Migration to iRestore (Cloud-based) software | Excel | Manual |
| Outage Log | Spreadsheet | Outage time/date, duration, and cause | Continue to update datasets needed for regulatory compliance | 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.

Since the 2022 BVES WMP Update, BVES made a few key updates to the main internal inspection enterprise system. BVES is continuing the goal to integrate all internal inspections into one central database into the current inspection application “iRestore” database. BVES also added a General Order 165 (GO 165) Detailed Inspections Portal, a General Order 174 (GO 174) Substation Inspection Portal, and a Vegetation Management inventory database. This created a reliable, searchable, comprehensive, and easily accessible database allowing BVES staff to continually meet or exceed all regulatory inspection requirements and achieve WMP inspection targets. Importantly, the enterprise system allows BVES to prioritize and track corrective action via work orders to inspection deficiencies and conduct trend analysis of work orders. The system allows management to understand the scope of work orders and ensure resources are being properly allocated to completing any outstanding work orders. iRestore is a customizable database that BVES can mold to meet current and future needs. The next update to the iRestore database will be an addition of a meter inspection portal that is expected to be completed in 2024.

### 8.1.6 Quality Assurance / Quality Control (QA/QC) (Tracking ID: GD_35)

*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 8-7 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 for the BVES Field Inspectors to manage and oversee the work completed by employees or contractors, including packaging QA/QC information for input to decision-making and workforce management processes. The qualifications for the BVES Field Inspectors are found in Table 8-9. 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.

Given the population of each work order or maintenance activity type unit (e.g., pole replacements, covered wire installation, tree attachment removals, wire mesh wrap installations, etc.) is less than 1,000 in any given year, BVES strives to achieve a quality control (QC) sample size of at least 10%. This value provides a confidence level of >95% and a margin of error of no more than 10%. This approach provides reasonable assurances on the quality of work and is realistically achievable by BVES's small staff. Additionally, as part of work order closing procedures, BVES staff conducts a quality assurance (QA) audit all work order documents (e.g., as-built drawings, work order instructions, material usage sheets, invoices, etc.) to ensure the work was properly documented. BVES Table 8-3 below demonstrates the quality control program tracking.

**BVES Table 8-3 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 |

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 (Tracking ID: GD_36)

*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).*

BVES follows General Order 95 (GO 95) Rule 18 requirements in managing and prioritizing open work orders. Work Orders are priority levels and associated timeframes for completion in accordance with GO 95 Rule 18 (e.g., Level 1, 2, or 3). BVES identifies work orders through its formal inspection programs as well as through as identified conditions by service crews, supervisors, and call-ins. The deficiencies are input into an asset enterprise system (BVES utilizes iRestore) where a work order number is created. Qualified BVES maintenance staff and contractors apply a level of severity in accordance with GO 95 Rule 18 and the iRestore program applies the corresponding timeframe for the remediation to be accomplished. If the repair is simple and does not require engineering design package (e.g., missing signage or visual strips), a Service Crew will be tasked to complete the work order, typically the same day. If the repair requires engineering design (e.g., pole replacement), the work order goes to the engineering planning group to have a design package created, but the situation will be at least mitigated down from a Level 1. Once a design package developed, the package is provided to Field Operations and construction crew is assigned to the work order to complete the required remediation.

BVES prioritizes open work orders first by level of severity defined by GO 95 Rule 18. Level 1 findings are addressed immediately by either completely remediating the issue or by making minor repairs to reclassify the issue to a Level 2 or level 3. Level 2 findings are assigned a timeframe of six months if in the HFTD Tier 3 area or 12 months if in the HFTD Tier 2 area. All Level 3 work orders are to be repaired within 60 months of being identified. BVES also prioritizes work orders within each level by HFTD. For example, HFTD Tier 3 Level 3 work orders have a higher priority over other areas. Finally, BVES priorities work orders within each level and HFTD area by higher risk circuits per BVES's the Fire Safety Circuit Matrix described in Section 6.2. For example, Level 2 work orders within the HFTD 2 area are prioritized based on the level of risk circuits have per BVES's Fire Safety Matrix. As BVES implements it Technosylva WRRM Risk Model, the model will be used in place of the Fire Safety Circuit Matrix to prioritize work orders.

At the time of this writing, BVES does not have any past due work orders. Any past due work orders are immediately prioritized for correction. Work orders approaching their due date, or past due work orders are automatically flagged to BVES maintenance supervisors by the enterprise system. Other considerations in assigning work orders to crews are the work order age and grouping orders geographically together. For example, if a crew is working on a higher priority work order, lower priority work orders on the same facility would also be assigned to the crew so that they may be corrected while the crew is on site.

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

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

BVES began populating its asset work order enterprise system to track work orders in the first quarter of 2023. With this tracking ability from the asset enterprise system, BVES will have the ability to conduct work order trend analysis. Conducting such trend analysis will be part of the maintenance supervisory element's routine. The trend analysis will be presented to management at periodic management meetings.

**Table 8-8 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 |

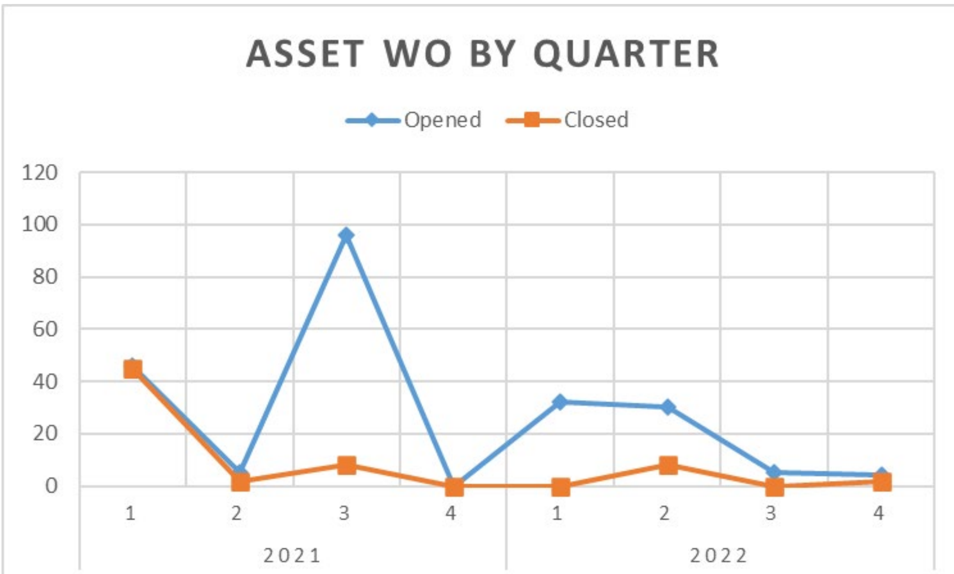



**Figure 8-2 Asset Work Orders by Quarter**

## 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 (Tracking ID: GD_37)*

*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. BVES 34.5kV sub-transmission system is fed by Southern California Edison's (SCE) sub-transmission systems at 34.5kV at two delivery points. In order to ensure that the BVES protective system is properly coordinated with SCE's protective system, BVES's protective curve settings are always set to the fast trip settings. Additionally, for over 20 years, it is BVES's policy to use the fast trip curve setting on all devices due to BVES's location within high fire risk areas.

Comparison of BVES's outage data to other California and US utilities for the last 10 years does not indicate this policy resulted in increased outages. For over 20 years, BVES has not experienced any reportable ignitions. Most BVES customers are residential or small commercial. Therefore, it is rare for customer equipment to cause an over current driven trip.

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 by utilizing the automatic testing feature on devices such as reclosers and fuse TripSavers. 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:

- From approximately November 1st through March 31st, the system is focused on safety and reliability and devices are set as follows:

  - All fuse TripSavers fuses are set to three trips to lockout.
  - All auto-reclosers are set to three trips to lockout.
  - Radford 34.5kV line is energized and its recloser set to three trips to lockout.
- 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 the following operational settings:
  - All TripSavers fuses are set to non-reclosing.
  - All auto-reclosers are set to non-reclosing.
  - Radford 34.5 kV line is 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 BVES Table 8-4 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.

**BVES Table 8-4 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.

In 2022, BVES started utilizing Technosylva's Wildfire Analyst Enterprise (WFA-E) application to monitor the wildfire risk at each point along its circuits. BVES has been gaining experience and confidence in this model and will develop protocols in 2023 to shift from utilizing the NFDRS protocols discussed above to utilizing the WFA-E to drive operational decisions with respect to wildfire risk and mitigations.

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 (Tracking ID: GD_38)*

*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*

Power outages are tracked internally through the SCADA system, trip savers, fault indicators and/or the FLISR system. Outages may also be reported through the Customer Call Center or through the BVES iRestore application in which the local Fire and Sheriff department directly report outages to BVES. Information collected provides a basic understanding of the issue and this information is relayed to the Service Crew (during normal working hours) or the Dutyman (afterhours) who's priority is to investigate any outage or issue in the field. These crews investigate outages in the field to determine the extent of the damage. This information is quickly communicated to management which determines the personnel, equipment and outside sources needed to optimize recovery times. As necessary, BVES will conduct work with associated fire risk by de-energizing work areas. BVES will notify the Big Bear Fire Department (BBFD) and/or Cal Fire if any ignitions or wildfires are detected. As recovery activities progress, the field crews communicate with management who will quickly adjust recovery resources and activities, as required.

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

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 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 (Tracking ID: GD_39)*

*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, which 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. For 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 (Tracking ID: GD_40)

*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*

*Table 8-9, Table 8-10, Table 8-11 are examples of the required information.*

**Table 8-9 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 Electrical Corporation Training/Qualification Programs |
|---|---|---|---|---|---|
| Field Inspector (BVES Employee) | Three years of Journeyman Lineman or above experience.<br>IBEW Journeyman Lineman status in good standing<br>Demonstrated knowledge and proficiency in GO 95 and GO 128.<br>Experience inspecting overhead and underground facilities.<br>Class C California Driver's License | Journeyman Lineman | 100% | 100% | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| Light Crew Foreman<br>(BVES Employee) | Three years of experience as a Journeyman Lineman or Service Crew Foreman.<br>IBEW Journeyman Lineman status in good standing.<br>Knowledge of:<br>Methods, materials, and tools used in electrical overhead and underground co3nstruction, maintenance, and repair work.<br>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.<br>Occupational hazards and standard safety precautions necessary in work.<br>Class A California Driver's License. | Journeyman Lineman | 100% | 100% | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| 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.<br>IBEW Journeyman Lineman status in good standing.<br>Knowledge of:<br>Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work.<br>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.<br>Inspection program requirements of GO 165 and GO 174.<br>Occupational hazards and standard safety precautions necessary in work.<br>Class A California Driver's License. | Journeyman Lineman | 100% | 100% | N/A |

| | | | | | |
|---|---|---|---|---|---|
| Substation Technician (BVES Employee) | Minimum five (5) years' experience observing and operating substation equipment.<br>Journeyman Lineman certification a plus.<br>Demonstrated ability to read and understand electrical system drawings and substation equipment technical manuals.<br>Class C California Driver License.<br>Sound knowledge of:<br>Methods, materials, and tools used in electrical distribution system substation construction, operations, maintenance, diagnostic, and repair work.<br>Principles of electrical theory as applied to distribution system substations and grid equipment (34.5 kV and 4.160 kV).<br>Inspection program requirements of GO 174.<br>SCADA and electric utility GIS systems.<br>IEEE-SA - National Electrical Safety Codes (NESC) as they pertain to electrical distribution | N/A | 100% | N/A | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| | substations and grid equipment | | | | |
| Utility Systems Specialist Inspector/Lead Inspector<br>(Contractor) | Overhead Distribution and/or Transmission distribution inspection experience (2-year min)<br>Identification of all overhead equipment<br>Current Driver License<br>Computer and GIS mapping experience | NESC and ANSI Inspection experience (1-year min)<br>Red Cross FA/CPR Certified<br>Wildfire Training | 100% | 100% | N/A |
| Geospatial Project Manager (Contractor) | 8 years of GIS and Remote Sensing Experience<br>5 years or more in a Supervisory Role Advanced Knowledge of LiDAR Sensors and Data<br>Advanced GIS Skills and Problem Solving | Geospatial Information Systems Professional (GISP) | 100% | 100% | ASPRS Certified Mapping Scientist, LiDAR |
| Geospatial Lead Analyst (Contractor) | 8 years of GIS and Remote Sensing Experience<br>Strong Quality Control and Detail<br>Advanced Knowledge of LiDAR Sensors and Data<br>Advanced GIS Skills and Problem Solving | N/A | 100% | N/A | ASPRS Certified Remote Sensing Technologist |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| Geospatial Technician (Contractor) | Solid Understand of GIS and Remote Sensing Science<br>Strong Attention to Detail<br>Strong Computer Skills<br>Work Independently | N/A | 100% | N/A | N/A |

**Table 8-10 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/Qualification Programs |
|---|---|---|---|---|---|
| Utility Engineer & Wildfire Mitigation Supervisor (BVES Employee) | Bachelor's Degree in an engineering field or a technical discipline required.<br>Eight years of planning, construction, or engineering experience including four years of administrative and supervisory experience. Utility experience preferred.<br>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% | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| | 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.<br>Seven years of experience in line operations working under a collective bargaining agreement or equivalent combination of experience and education required<br>Thorough knowledge of GO 95/165 and Construction Methods | N/A | 100% | N/A | N/A |
| Regulatory Compliance Project | Bachelor's Degree in Electrical Engineering, or related field. | Professional Engineer's (PE) license in the | 50% | 100% | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| Engineer (BVES Employee) | Strong experience with overhead and underground distribution and substation design. Knowledge of SCADA and automated grid systems are highly desirable.<br>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).<br>Experience with California Environmental Quality Act (CEQA) process.<br>Experience and working knowledge of CPUC General Orders 95, 128, 165 and 174. | 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. | | | |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| Project Coordinator (BVES Employee) | Associates or bachelor's degree preferred<br>Project Management course work and Project Management Professional (PMP) certification preferred<br>Four years of experience in construction projects including demonstrable project management experience | N/A | 100% | N/A | N/A |
| Utility Planner I (BVES Employee) | Bachelor's degree in Engineering or successful completion of a Utility Planning Certification required.<br>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 | 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.<br>Experience identifying in field electrical equipment.<br>Experience in distribution facility overhead design. | N/A | 100% | N/A | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| | Demonstrated Experience in AutoCAD design software and experience with GIS software (desired).<br>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.<br>IBEW Journeyman Lineman status in good standing.<br>Knowledge of:<br>Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work.<br>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.<br>Occupational hazards and standard safety precautions necessary in work. | Journeyman Lineman | 100% | 100% | N/A |

| **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/Qualification Programs** |
|---|---|---|---|---|---|
| | Class A California Driver's License. | | | | |
| 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.<br>IBEW Journeyman Lineman status in good standing.<br>Knowledge of:<br>Methods, materials, and tools used in electrical overhead and underground construction, maintenance, and repair work.<br>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.<br>Inspection program requirements of GO 165 and GO 174. | Journeyman Lineman | 100% | 100% | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| | Occupational hazards and standard safety precautions necessary in work.<br>Class A California Driver's License. | | | | |
| Lineman (BVES Employee) | Certified completion of a union or company recognized lineman apprenticeship training program.<br>IBEW Journeyman Lineman status in good standing.<br>Past experience in climbing wooden power poles and working on high voltage power lines.<br>Knowledge of basic principles of electricity, current theory mathematics, GO 95 and 128 and all applicable codes, accident prevention orders and ordinances.<br>Knowledge of methods, material and tools used in the construction, maintenance and repair of an overhead/underground transmission, distribution, and substation electrical system<br>Must possess or obtain within 6 months a valid Class A California Driver's License. | Journeyman Lineman | 80% | 100% | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| Substation Technician (BVES Employee) | Minimum five (5) years' experience observing and operating substation equipment.<br>Journeyman Lineman certification a plus.<br>Demonstrated ability to read and understand electrical system drawings and substation equipment technical manuals.<br>Sound knowledge of:<br>IEEE-SA - National Electrical Safety Codes (NESC) as they pertain to electrical distribution substations and grid equipment.<br>Methods, materials, and tools used in electrical distribution system substation construction, operations, maintenance, diagnostic, and repair work.<br>Principles of electrical theory as applied to distribution system substations and grid equipment (34.5 kV and 4.160 kV).<br>Inspection program requirements of GO 174.<br>SCADA and electric utility GIS systems. | N/A | 100% | N/A | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| | Class C California Driver License. | | | | |

**Table 8-11 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 Corporation Training/Qualification Programs |
|---|---|---|---|---|---|
| Utility Engineer & Wildfire Mitigation Supervisor (BVES Employee) | Bachelor's Degree in an engineering field or a technical discipline required.<br>Eight years of planning, construction, or engineering experience including four years of administrative and supervisory experience. Utility experience preferred.<br>Work experience in an area with strong compliance regimes. Experience interacting with utility regulators and knowledge of regulatory processes preferred.<br>Knowledge of overhead and underground line construction, substations, transformation, cabling, voltage drop, circuit protection and | Professional Engineer license in California required. If not held, must obtain within 2 years of employment. | 100% | 100% | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| | 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.<br>Seven years of experience in line operations working under a collective bargaining agreement or equivalent combination of experience and education required.<br>Thorough knowledge of GO 95/165 and Construction Methods. | N/A | 100% | N/A | N/A |
| Regulatory Compliance Project Engineer (BVES Employee) | Bachelor's Degree in Electrical Engineering, or related field.<br>Strong experience with overhead and underground distribution and substation design. Knowledge of SCADA and automated grid systems are highly desirable. | Professional Engineer's (PE) license in the California is strongly desired. Note, that if the | 50% | 100% | N/A |

| 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/Qualification Programs |
|---|---|---|---|---|---|
| | 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).<br>Experience with California Environmental Quality Act (CEQA) process.<br>Experience and working knowledge of CPUC General Orders 95, 128, 165 and 174. | 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. | | | |

# 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 planning*

### *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 8-12 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 | 8.2.3.1; pg. 201<br>8.2.3.3; pg. 202<br>8.2.3.5; pg. 206 |
| 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 | 8.2.3.6; pg. 206 |
| 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 | 8.2.2.1; pg. 195<br>8.2.2.2; pg. 196<br>8.2.2.3; pg. 197<br>8.2.2.4; pg. 198<br>8.2.2.5; pg. 198<br>8.2.2.6; pg. 199<br>8.2.3.5; pg. 206 |

| 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) |
|---|---|---|---|---|---|---|
| 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 | GO 95 | N | SME system audit | 31-Dec-23 | 8.2.4; pg. 208 |
| Improve quality assurance and quality control program on vegetation management inspection and clearance work and asset inspection. | Quality assurance/quality control, VM_16 | GO 95, GO 165 | N | N/A | 31-Dec-23 | 8.2.5; pg. 211 |
| 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 | PRC 4292, GO 95, GO 165, GO 174 | N | N/A | 31-Dec-25 | 8.2.3.7; pg. 207 |

**Table 8-13 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 | PRC 4292, GO 95, GO 165, GO 174 | Y | Continue providing information and meeting with the community to promote sustainable and fire-resilient land | 31-Dec-32 | 8.2.3.7; pg. 207 |
| 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 | Evaluate risk-based evaluation cycles using information from Detailed, Ground Patrol, LiDAR and UAV Inspection programs | 31-Dec-32 | 8.2.2.1; pg. 195<br>8.2.2.2; pg. 196<br>8.2.2.3; pg. 197<br>8.2.2.4; pg. 198<br>8.2.2.5; pg. 198<br>8.2.2.6; pg. 199<br>8.2.3.5; pg. 206 |
| Evolve vegetation clearance cycles to be risk-based | Pole clearing, VM_7 Clearance, VM_9 Substation defensible | GO 95, GO 165, GO 174 | Y | Evaluate risk-based vegetation clearance cycles from Detailed, Ground, Patrol, LiDAR, UAV | 31-Dec-32 | 8.2.3.1; pg. 201<br>8.2.3.3; pg. 203<br>8.2.3.5; pg. 206 |

| 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) |
|---|---|---|---|---|---|---|
| | space, VM_11 | | | Inspection Programs | | |

**BVES Table 8-5 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. |

| **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** |
| 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 8-14 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 |
|---|---|---|---|---|---|---|---|---|---|
| Wood and slash management | VM_8 | Contractor Adhered to Waste Removal | Waste Removal Requirements Met | 3.62% | Waste Removal Requirements Met | 3.62% | Waste Removal Requirements Met | 3.62% | Contract Status |
| Clearance | VM_9 | Circuit Miles Cleared | 72 | 3.02% | 72 | 3.02% | 72 | 3.02% | Quantitative (QDR) |
| Fall-in mitigation | VM_10 | Number of trees remediated or removed to prevent fall-in | 88 | 3.02% | 88 | 3.02% | 88 | 3.02% | Quantitative (QDR) |
| Substation defensible space | VM_11 | Substations inspected and cleared | 13 | 3.02% | 13 | 3.02% | 13 | 3.02% | Quantitative (QDR) |
| High-risk species | VM_12 | WMP Plan Review and Vegetation Discussion with Experts | WMP Plan Review and Vegetation Discussion with Experts | 3.02% | WMP Plan Review and Vegetation Discussion with Experts | 3.02% | WMP Plan Review and Vegetation Discussion with Experts | 3.02% | Version History |

| 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 |
|---|---|---|---|---|---|---|---|---|---|
| Fire-resilient rights-of-way | VM_13 | WMP Plan Review and Vegetation Discussion with Experts | WMP Plan Review and Vegetation Discussion with Experts | 4.51% | WMP Plan Review and Vegetation Discussion with Experts | 4.51% | WMP Plan Review and Vegetation Discussion with Experts | 4.51% | Version History |
| Emergency response vegetation management | VM_14 | Verification of Readiness and Review of Plan | Verification of Readiness and Review of Plan | 3.02% | Verification of Readiness and Review of Plan | 3.02% | Verification of Readiness and Review of Plan | 3.02% | Version History |
| Vegetation management enterprise system | VM_15 | Ongoing Monitoring and Maintenance | 100% | 3.02% | 100% | 3.02% | 100% | 3.02% | Budget Review |
| Quality assurance / quality control | VM_16 | Number of Vegetation QCs | 72 | 4.36% | 72 | 4.36% | 72 | 4.36% | Quantitative (QDR) |
| Open work orders | VM_17 | No discrepancy exceeding GO95 resolution timeframes | All WO resolved within GO 95 Timeframe | 3.02% | All WO resolved within GO 95 Timeframe | 3.02% | All WO resolved within GO 95 Timeframe | 3.02% | WO Log |

| **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** |
|---|---|---|---|---|---|---|---|---|---|
| Workforce planning | VM_18 | Verify Appropriate Staffing Levels for Wildfire Related Activities | Staffing Level Verified | 3.62% | Staffing Level Verified | 3.62% | Staffing Level Verified | 3.62% | Meeting Minutes |

**Table 8-15 Vegetation 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** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Vegetation inspections / Detailed Inspection | VM_1 | Circuit Miles Inspected | 60 | 100 | 134 | *4.36%* | 0 | *40* | *51* | *4.36%* | *53* | *4.36%* | Quantitative (QDR) |
| Vegetation inspections / Patrol Inspection | VM_2 | Circuit Miles Inspected | 0 | 211 | 211 | *4.36%* | 0 | 211 | 211 | *4.36%* | 211 | *4.36%* | Quantitative (QDR) |

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Vegetation inspections / UAV HD Photography / Videography | VM_3 | Circuit Miles Inspected | 0 | 211 | 211 | *4.36%* | 0 | 211 | 211 | *4.36%* | 211 | *4.36%* | Quantitative (QDR) |
| Vegetation inspections / LiDAR Inspection | VM_4 | Circuit Miles Inspected | 0 | 211 | 211 | *4.36%* | 0 | 211 | 211 | *4.36%* | 211 | *4.36%* | Quantitative (QDR) |
| Vegetation inspections / 3rd Party Ground Patrol | VM_5 | Circuit Miles Inspected | 0 | 211 | 211 | *4.36%* | 0 | 211 | 211 | *4.36%* | 211 | *4.36%* | Quantitative (QDR) |
| Vegetation inspections / Substation Inspection | VM_6 | Circuit Miles Inspected | 0 | 211 | 211 | *4.35%* | 0 | 211 | 211 | *4.35%* | 211 | *4.35%* | Quantitative (QDR) |

### *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 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 influence 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 8-16 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 |

| Performance Metrics | 2020 | 2021 | 2022 | 2023 Projected | 2024 Projected | 2025 Projected | Method of Verification (e.g., third-party evaluation, QDR) |
|---|---|---|---|---|---|---|---|
| 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 8-17 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 (Tracking ID: GD_25, VM_1)*

*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)*

**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 GO 95 and GO 165 requirements. In these Detailed Inspections vegetation and individual trees in the rights-of-way are carefully examined, visually, and discrepancies are recorded. This inspection is thorough and is more time consuming than Patrol Inspections. Individual pieces of equipment and structures are carefully examined to determine the condition of each rated and recorded component and vegetation clearances to bare conductor and other components. Identifying vegetation encroachments to minimum clearance requirements (as established by GO-95 or BVES, whichever is greater) is the first step in correcting such occurrences, which in turn reduces the probability of ignitions due to vegetation contacting bare conductors.

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

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

Detailed Inspection findings are rated in accordance with GO 95 Rule 18 (level 1, 2, or 3) and entered 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 and Updates**

BVEs completed all scheduled detailed inspections for 2022. Additionally, BVES fully transitioned into using a new inspection enterprise system (iRestore). iRestore provides better documentation of all identified vegetation issues by providing an exact geospatial location and high-resolution pictures. This helps reduce response time for vegetation crew when tasked with correcting the issue. BVES also created a feature class of all major woody stems in the entire service area.

**Roadblocks**

Environmental issues such as snow and ice can often affect detailed inspection. This can delay inspections for accessibility and safety reasons.

#### *8.2.2.2 Patrol Inspection (Tracking ID: GD_26, VM_2)*

**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 GO 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.

**Accomplishments and Updates**

BVES completed patrol inspections on all of the service territory in 2022. Additionally, BVES fully transitioned into using a new inspection enterprise system (iRestore). iRestore provides better documentation of all identified vegetation issues by providing an exact geospatial location and high-resolution pictures. This helps reduce response time for vegetation crew when tasked with correcting the issue.

**Roadblocks**

Environmental issues such as snow and ice can often affect detailed inspection. This can delay inspections for accessibility and safety reasons.

#### *8.2.2.3 UAV HD Photography/Videography Inspection (Tracking ID: GD_27 – GD_28 – VM_3)*

**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.

**Accomplishments and Updates**

In 2022, BVES completed UAV HD Photography/videography inspections on all of the service territory. A contractor put all of the photographs and data through a QA/QC analysis. A detailed report was provided to BVES of all potential defects. Once received BVES prioritized the potential defects and made repairs where it was necessary. In 2023, BVES is planning for the UAV inspection program to identify connection devices throughout the system.

**Roadblocks**

Environmental issues such as snow and ice can affect the ability of the UAV inspection teams to access some areas during certain times of the year. Concerned customers that do not want drones flying near/around their property have also delayed the inspection. Most of the time, a resolution can be found and the inspection continues.

#### *8.2.2.4 LiDAR Inspection (Tracking ID: VM_4 – GD_29)*

**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 and Updates*

In 2022, BVES completed LiDAR inspections on all of the service territory. Since BVES began LiDAR inspection in 2020, vegetation density around the power lines has significantly reduced. In 2020, the LiDAR inspection measured 25.44% vegetation density. In 2022, vegetation density had been reduced down to 19.82%. The contractor that conducts the UAV LiDAR inspection has acquired approval from the Federal Aviation Administration (FAA) to fly a fixed wing drone without line of sight. This new technique will significantly increase the speed at which the inspection will be conducted.

*Roadblocks*

BVES utilizes a vehicle mounted LiDAR system for a majority of the inspection. For the areas not accessible by road, BVES has had to use a UAV that was operated only by line of sight. This made inspection of these areas very difficult and time consuming.

#### *8.2.2.5 3rd Party Ground Patrol Inspection (Tracking ID: VM_5 – GD_30)*

*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.

*Accomplishments and Updates*

In 2022, BVES completed a 3rd Party Ground Patrol Inspection on the entirety of the service area. All of the findings where reinspected by BVES crews to determine a remedy. No updates are planned for future inspections.

*Roadblocks*

Access issues to property and government land caused minor delays for the inspection teams. All of the issues were able to be resolved in a timely manner and the inspections were completed on time.

#### *8.2.2.6 Substation Inspection (Tracking ID: VM_6 – GD_32)*

*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 and Updates*

In, 2022 BVES completed monthly inspections on all substations in the service territory. All vegetation issues identified in the inspections were corrected in a timely manner. No updates are planned for future inspections.

*Roadblocks*

Environmental issues such as snow and ice can affect the access to substations in the winter months. No inspections were past due in 2022.

### 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.*

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 according to PRC 4292 requirements.

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. 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 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 also conducts vegetation clearance including fuel management and removal of fuels along its power lines according GOs and applicable standards, regardless of area. Additionally, BVES recognizes the community imperative to carry out these activities in a manner that meets or exceeds the requirements, especially in higher risk areas. BVES conducts vegetation management on a cycle schedule. However, BVES conducts inspections of high-risk areas and will divert crews from the cycle schedule on a priority basis to remedy any issues found in the inspections. Fuel management in the right-of-way in high-risk areas are prioritized for removal as they are identified. Vegetation waste from clearance activities is removed from the right-of-way as well as slash within or near the right-of way.

Since the 2022 WMP, BVES has committed to exchanging information with other utilities to determine best practices for slash removal vegetation management activities. Additionally, the iRestore app was implemented into vegetation management activity tracking. BVES will continue to consider additional improvements to its vegetation management program.

### *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 encroach electrical infrastructure, thereby preventing wildfires.

Base of Poles/Structures: For poles or structures that have non-exempt equipment per CALFIRE requirements, all flammable material and vegetation in a 10-foot radius around the base of the pole or structure shall be cut down and removed during each normal vegetation management cycle clearance visit. Exceptions per the effective California Power Line Fire Prevention Field Guide are authorized. BVES also clears around exempt poles, 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.

*Updates to this Initiative:*

BVES has not made changes since the last WMP submission. Currently, BVES evaluation demonstrates that there is no need to update the initiative.

#### *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.

Updates to this Initiative:

BVES has not made changes since the last WMP submission. Currently, BVES evaluation demonstrates that there is no need to update the initiative.

#### *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.

*Updates to this Initiative:*

BVES has not made changes since the last WMP submission. Currently, BVES evaluation demonstrates that there is no need to update the initiative.

#### *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).

*Updates to this Initiative:*

BVES has not made changes since the last WMP submission. Currently, BVES evaluation demonstrates that there is no need to update the initiative.

#### *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.

*Updates to this Initiative:*

BVES has not made changes since the last WMP submission. Currently, BVES evaluation demonstrates that there is no need to update the initiative.

#### *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.

*Updates to this Initiative:*

BVES has not made changes since the last WMP submission. Currently, BVES evaluation demonstrates that there is no need to update the initiative.

#### *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 encroach 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 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.

*Updates to this Initiative:*

BVES has not made changes since the last WMP submission. Currently, BVES evaluation demonstrates that there is no need to update the initiative.

#### *8.2.3.8 Emergency Response Vegetation Management (VM_14)*

*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.

*Updates to this Initiative:*

BVES has not made changes since the last WMP submission. Currently, BVES evaluation demonstrates that there is no need to update the initiative.

### 8.2.4 Vegetation Management Enterprise System (VM_15)

*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) (VM_16)

*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 8-18 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 qualifications for these individuals are described in Table 8-20.

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.

**BVES Table 8-6 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 2023, 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, more specifically 18 QC reviews per quarter. BVES selected 72 as its annual target based off of its qualified staff availability (6 individuals conducting at minimum 1 QC review a month) and wanting to maintain regularity of review. 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 (BVES staff qualifications are discussed in Section 8.2.7).

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).
2. Urgent (Priority 2) vegetation orders will be corrected within 30 days.
3. 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 record-keeping and presents the number of trees targeted for remediation with those that have passed a QC review and those that have failed. This results in an efficiency rating based on parameters that align with General Order 95 Rule 35 and BVES's enhanced vegetation management practices.

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 (VM_17)

*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.*

BVES uses General Order 95 (GO 95) Rule 18 requirements as guidance for managing and prioritizing open work orders. Work Orders are given priority levels and associated timeframes for completion. In the second quarter of 2023, BVES will move to using iRestore (Enterprise System) to track all open vegetation work orders. When a discrepancy is identified by the vegetation inspector, a work order is created and a severity level (Level 1, 2, or 3 in accordance with GO 95 Rule 18) is applied. The severity will dictate the timeframe for remediation. For vegetation related discrepancies timeframe and example situations are as follow:

- Level 1 – Immediate Action – Vegetation Order Issued to Contractor for Immediate Action
    - Vegetation contacting, nearly contacting or arcing to high voltage conductor, vegetation contacting low voltage conductor and compromising structure, etc.

- Level 2 – Action within 30 days – Vegetation Order Issued to Contractor for Action within 30 days
    - Vegetation within 48 inches of high voltage lines, vegetation causing strain or abrasion on low voltage conductor, tree or portions of tree that are dead, rotten, or diseased that may fall into power lines, etc.

- Level 3 – Non-urgent Normal Cycle Action – Vegetation Order issued to Contractor for Action during the next normal vegetation cycle

BVES prioritizes open work orders first by level of severity defined by GO 95 Rule 18, then by HFTD area for a specific level. For example, an HFTD 3 Level 2 work order is prioritized over an HFTD 2 Level 2 work order. Finally, BVES priorities work orders within each level and HFTD area by higher risk circuits per BVES's the Fire Safety Circuit Matrix described in Section 6.1. For example, Level 2 work orders within the HFTD 2 area are prioritized based on the level of risk circuits have per BVES's Fire Safety Circuit Matrix.

BVES will begin populating its vegetation work order enterprise system to track work orders in the second quarter of 2023. With this tracking ability from the enterprise system, BVES will have the ability to conduct work order trend analysis. Until this change, BVES cannot provide trend analysis on its work orders. Conducting such trend analysis will be part of the Wildfire Mitigation & Reliability Engineer routine. The trend analysis will be presented to management at periodic management meetings.

BVES does not currently have any past due work orders. If BVES were to have past due work orders, the issue would immediately be prioritized. Work orders approaching their due date as well as work orders that are past due will be automatically flagged to BVES Wildfire Mitigation & Reliability Engineer by the enterprise system once it is put into use in the second quarter of 2023.

**Table 8-19 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 |

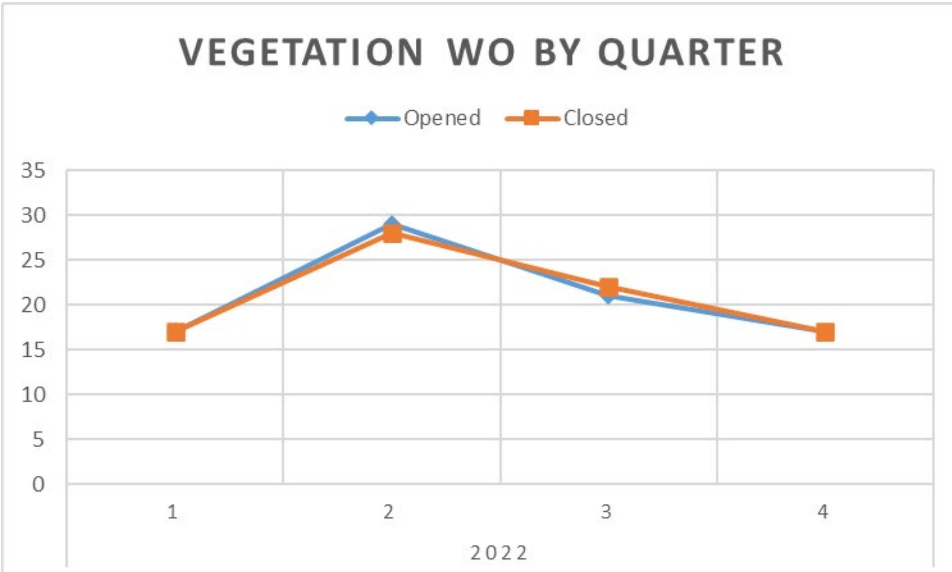



**Figure 8-3 Vegetation Management Work Orders by Quarter**

### 8.2.7 Workforce Planning (VM_18)

*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 8-20 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/Qualification 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 | Professional Engineer license in California required. If not held, must obtain within 2 years of employment. | 100% | 100% | *N/A* | *N/A* | None required |

| 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/Qualification Programs Improvements |
|---|---|---|---|---|---|---|---|
| | with strong compliance regimes. Experience interacting with utility regulators and knowledge of regulatory processes preferred.<br><br>Knowledge of overhead and underground line construction, substations, transformation, cabling, voltage drop, circuit protection and protection coordination, rules, rates and schedules, Company | | | | | | |

| 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/Qualification Programs Improvements |
|---|---|---|---|---|---|---|---|
| | policies and procedures, service requirements, material management, electrical codes, budgeting and electrical theory and application. | | | | | | |
| Wildfire Mitigation and Reliability Engineer (BVES Employee) | Bachelor of Science degree in Engineering, Mathematics, Physics, or other related technical discipline.<br>Prior electric utility experience preferred. | N/A | 100% | 100% | *N/A* | *N/A* | None required |

| 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/Qualification Programs Improvements |
|---|---|---|---|---|---|---|---|
| | Understanding of statistical analysis and probabilistic methods preferred.<br>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 | | | | | | |

| 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/Qualification Programs Improvements |
|---|---|---|---|---|---|---|---|
| | systems preferred. | | | | | | |
| Field Inspector (BVES Employee) | Three years of Journeyman Lineman or above experience.<br>Experience inspecting overhead and underground facilities.<br>Class C California Driver's License | IBEW Journeyman Lineman status in good standing<br>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<br>(Contractor) | Overhead Distribution and/or Transmission distribution inspection | NESC and ANSI Inspection experience (1-year min) | *N/A* | *N/A* | 100% | 100% | None required |

| 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/Qualification Programs Improvements |
|---|---|---|---|---|---|---|---|
| | experience (2-year min)<br>Identification of all overhead equipment<br>Current Driver License<br>Computer and GIS mapping experience | Red Cross FA/CPR certified<br>Wildfire Training | | | | | |
| Geospatial Project Manager (Contractor) | 8 years of GIS and Remote Sensing Experience<br>5 years or more in a Supervisory Role<br>Advanced Knowledge of LiDAR Sensors and Data | Geospatial Information Systems Professional (GISP) | *N/A* | *N/A* | 100% | 100% | ASPRS Certified Mapping Scientist, LiDAR |

| 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/Qualification Programs Improvements |
|---|---|---|---|---|---|---|---|
| | Advanced GIS Skills and Problem Solving | | | | | | |
| Geospatial Lead Analyst (Contractor) | 8 years of GIS and Remote Sensing Experience<br>Strong Quality Control and Detail<br>Advanced Knowledge of LiDAR Sensors and Data<br>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 | N/A |

| 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/Qualification Programs Improvements |
|---|---|---|---|---|---|---|---|
| | Sensing Science<br>Strong Attention to Detail<br>Strong Computer Skills<br>Work Independently | | | | | | |
| Tree Trim General Foreman/Supervisor<br>(Contractor) | 5 years of line clearance tree pruning experience in a Foreman role<br>Line clearance Certification<br>Current California Driver License<br>General Computer knowledge | ISA Certification<br>Line-clearance qualified tree-trimmer | *N/A* | *N/A* | 100% | 100% | ISA Continuing Education Requirements |

| 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/Qualification Programs Improvements |
|---|---|---|---|---|---|---|---|
| Tree Trimmer (Contractor) | Strong work ethic<br>Current California Driver License (Class B permit)<br>General computer skills | ISA Certification<br>Line-clearance qualified tree-trimmer | *N/A* | *N/A* | 100% | 100% | ISA Continuing Education Requirements |

# 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 8-21 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 program and evaluate effectiveness. | Grid monitoring systems, SAF_3 | N/A | Completion of Pilot. Internal review of results | 31-Dec-23 | Section 8.1.2.8; pp. 135 |
| Complete installation of fault indicators (FIs). Evaluate need for additional (Fis) | Grid monitoring systems, SAF_2 | N/A | Close of work order. Internal review of cost-benefit | 31-Dec-23 | Section 8.3.3.3; pp. 237 |
| Evaluate need for additional weather stations. | Environmental monitoring systems, SAF_1 | N/A | N/A | 31-Dec-25 | Section 8.3.1; pp. 225 |
| Evaluate need for additional HD Alert Cameras. | Ignition detection systems, SAF_4 | N/A | N/A | 31-Dec-25 | Section 8.3.1; pp. 225 |
| Develop and implement Fire Potential Index. | Fire Potential Index, SAF_6 | N/A | FPI Tool – Technosylva | 31-Dec-23 | 6.4.3; pp. 76 7.2.1; pp. 96 8.3.6; pg. |
| Improve staff proficiency in utilizing advanced fire threat weather forecasting tools. | Weather forecasting, SAF_5 | N/A | Multiple Members of BVES team are able to proficiently use tool | 31-Dec-23 | 7.2.1; pp. 248 |

*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 8-22 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 | 7.2.1; pp. 248 |

*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 8-23 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 / Advanced Weather Monitoring and Weather Stations | SAF_1 | Ongoing Monitoring and Maintenance | 100 % | 38% | 100 % | 38% | 100 % | 38% | Budget Review |
| Grid monitoring systems / Install Fault Indicators | SAF_2 | Number of FIS installed | 30 | 84% | 0 | N/A | 0 | N/A | Quantitative |
| Grid monitoring systems / Online Diagnostic System | SAF_3 | Number of circuits installed on per year | 2 | 3.62 % | 1 | 3.62 % | 1 | 3.62 % | Quantitative |
| Ignition detection systems / HD ALERTWildfire Cameras | 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 % | 3.76 % | 100 % | 3.76 % | 100 % | 3.76 % | Budget Review |

| 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 |
|---|---|---|---|---|---|---|---|---|---|
| Fire Potential Index | SAF_6 | Ongoing Monitoring and Maintenance | 100 % | 3.46 % | 100 % | 3.46 % | 100 % | 3.46 % | 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 8-24 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) |
|---|---|---|---|---|---|---|---|---|
| Clearance – SAF_1 | miles | N/A | N/A | 86.84 | 72 | 72 | 72 | QDR |

| Performance Metrics | Unit | 2020 | 2021 | 2022 | 2023 Projected | 2024 Projected | 2025 Projected | Method of Verification (e.g., third-party evaluation, QDR) |
|---|---|---|---|---|---|---|---|---|
| Substation Defensible Space – SAF_4 | miles | N/A | N/A | N/A | 13 | 13 | 13 | QDR |
| Fall-in Mitigation – SAF_6 | miles | N/A | N/A | N/A | 88 | 88 | 88 | 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 8-25 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<br>Wind Velocity & Direction (Steady & Gust)<br>Relative Humidity<br>Barometric Pressure<br>Precipitation | Continuous Monitoring | Improved weather monitoring and forecasting<br>Model Validation<br>SCADA Connected | As needed |
| HD Cameras (ALERTWildfire HD Cameras) | 15 cameras in 7 Key Locations Across BVES service Territory | Visual Observation | Continuous During Hazardous Conditions | Visual Awareness in areas adjacent to electrical assets. Immediate fire alert | As needed; to be tracked and reported in future WMPs |

## Weather Stations (SAF_1)

Weather stations are a key component in situational awareness and wildfire risk mitigation strategies. In 2021, BVES completed the installation of all 20 weather stations manufactured by Orion. These stations measure temperature, relative humidity, barometric pressure, wind direction and speed, and precipitation.

These sensors communicate over wireless cellular communications to help BVES obtain service territory specific data and information at one-minute interval recordings. Currently the weather station data is captured on its own platform. The data gathered from the weather stations has also been integrated into the Technosylva Database.

BVES asserts a total of 20 weather stations will provide sufficient coverage of its 32 sq. mi. service area. These 20 weather stations are currently on an as needed maintenance schedule based on the manufacturer's recommendations. When a maintenance work order is issued for a given weather station calibration is included as part of said work order. Due to the weather stations being in remote locations in the service territory, BVES does not project a change to a regular maintenance schedule unless the accuracy of data is brought into question.

**BVES Table 8-7 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 | In substation | 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 |

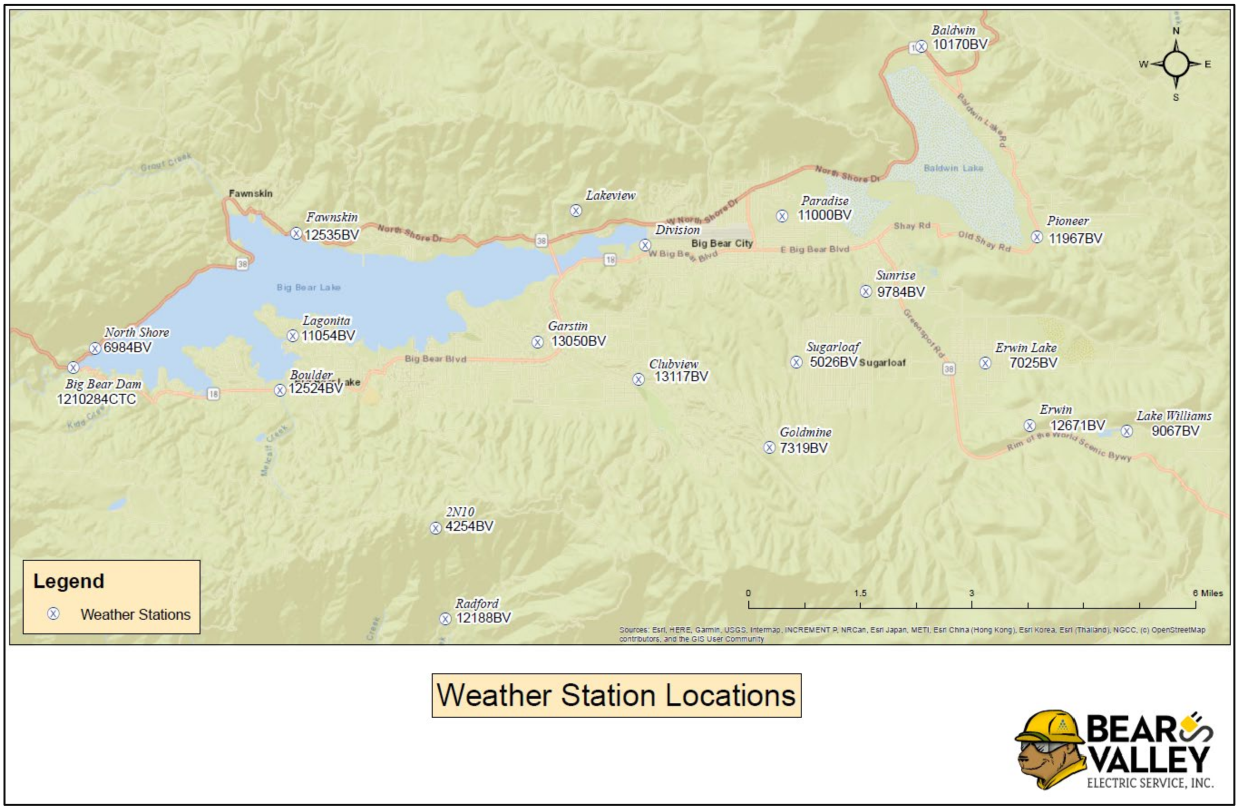



**Figure 8-4 BVES Weather Station Locations**

## <u>HD Cameras (ALERTCalifornia HD Cameras) (SAF_4)</u>

The HD Cameras that BVES has strategically placed around its service territory are a key component in situation awareness, specifically in instances of elevated fire risk. The HD Cameras provide visual awareness into the territories adjacent to electrical assets and maintain live accounts of risk drivers during hazardous weather conditions. The cameras owned by BVES will also contribute to the Southern California system, which comprises a shared network of utility, academic, and fire response cameras to provide coverage of live feeds to monitor conditions and assist emergency event awareness. During high threat conditions, BVES deploys personnel to supplement camera information with observations by qualified personnel.

BVES currently has the ALERTCalifornia cameras on an as needed basis maintenance schedule. There is no current tracking associated with the camera's and BVES plans to track this in more detail in future WMP submissions.

**BVES Table 8-8 ALERT Wildfire HD Camera List**

| ALERTCalifornia HD Camera (Quantity) | Latitude | Longitude |
|---|---|---|
| Bear Mountain (5) | 34.21260737482088 | -116.86633705780157 |
| Snow Summit (2) | 34.22276789245118 | -116.89473063338028 |

| ALERTCalifornia HD Camera (Quantity) | Latitude | Longitude |
|---|---|---|
| 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 8-26 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, University of California, San Diego (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 (Tracking ID: GD_14 – GD_16 – GD_17)*

*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 8-27 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 8-28:*

- *Description – A description of the planned initiative activity*
- *Impact – Reference to and description of the impact of the initiative activity on each risk and risk component*
- *Prioritization – A description of the x% risk impact (see Section 8.1.1.2 for explanation)*
- *Schedule – A description of the planned schedule for implementation*

**Table 8-28 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<br>Reduce fault identification and location time to improve service restoration | 84% | 129 in 2023 |

#### *8.3.3.4 Evaluating Mitigation Initiatives (WMSD_1)*

*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 Customer Average Interruption Duration Index (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 (GD_34)*

*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 maintains a SCADA system as its Operational Enterprise system. BVES SCADA system currently monitors and can controls the BVPP as well as all of its upgraded substations, and remotely controlled devices. BVES's SCADA system is only physically monitored during normal business hours but the system sends alerts designated resources via text on a 24/7/365 basis. BVES's BVPP Operators, Substation Technicians, and line crews regularly monitor SCADA as a function of their day-to-day operations.

BVES SCADA system is an IT-managed asset. BVES IT has standard operating procedures for updating and patching SCADA and its associated devices that include, but are not limited to, testing changes outside their operating environment before deployment, version control, comparison of field readings against SCADA displays, etc. BVES IT make sure to verify with all parties that the time is acceptable before performing the deployment of updates, changes, or patches.

## 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 (SAF_4)*

*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 8-29 Fire Detection Systems Currently Deployed**

| Detection System | Capabilities | Companion Technologies | Contribution to Fire Detection and Confirmation |
|---|---|---|---|
| HD Cameras (ALERTWildfire HD Cameras) | Continuous Monitoring During Hazardous Conditions<br>15 cameras in 7 Key Locations Across BVES service Territory | Technosylva – Fire Growth Potential Software | Visual Awareness in areas adjacent to electrical assets.<br>Immediate fire alert |
| Fire Spread Modeling<br>(SA-8) | BVES is utilizing Technosylva's FireCast and FireSim Applications to predict fire spread and consequence outputs such as fire perimeter size, structures impacted, and populations affected | N/A | Capability to forecast consequences that wildfire will have on a particular area |

**BVES Table 8-9 ALERTCalifornia 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 |

**Satellite Infrared Imagery**
BVES is not currently pursuing or planning on utilizing satellite infrared imagery for ignition detection. BVES’s service area is 32 square-miles (less if you subtract the lakes). Based on the small size and other systems available to detect ignitions, BVES has determined to not pursue satellite infrared imagery.

*Highlight any improvements made since the last WMP submission*
N/A – BVES is currently not pursuing satellite infrared technology.

*General location of detection sensors (e.g., HFTD or entire service territory)*
N/A – BVES is currently not pursuing satellite infrared technology.

*Resiliency of Sensor Communication Pathways*
N/A – BVES is currently not pursuing satellite infrared technology.

*Integration of Sensor Data into Machine Learning or Artificial Intelligence (AI) Software*
N/A – BVES is currently not pursuing satellite infrared technology.

*Role of Sensor Data in Risk Response*
N/A – BVES is currently not pursuing satellite infrared technology.

*False Positives Filtering*
N/A – BVES is currently not pursuing satellite infrared technology.

*Time Between Detection and Confirmation*
N/A – BVES is currently not pursuing satellite infrared technology.

*Security Measures for Network-Based Sensors*
N/A – BVES is currently not pursuing satellite infrared technology.

**HD Video Cameras**

In partnership with the University of California, San Diego (UCSD) ALERTCalifornia (formerly AlertWIdlfire) network, BVES utilizes the network's HD cameras provide full visibility into the Big Bear Valley. Continuous live feeds help inform BVES, Big Bear Fire Department, San Bernardino Fire Department, San Bernardino Office of Emergency Services, CAL FIRE and other agencies with fast information gathering for ability to confirm smoke/fire location and direction of growth in Big Bear Valley. The information is critical for BVES to protect assets and PSPS decision-making as well as for Fire Departments to evaluate and dispatch resource quickly. BVES continues to work with stakeholders to ensure the HD ALERTCalifornia network has sufficient cameras. The cameras provide live high-definition video feed and infrared detection capability is being incorporated into the system.

*Highlight any improvements made since the last WMP submission*
BVES completed the installation of a total of 15 camera in 7 locations in partnership with UCSD's ALERTCalifornia network to provide full visibility into the Big Bear Valley.

*General location of detection sensors (e.g., HFTD or entire service territory)*
15 cameras in 7 locations currently provide full coverage and beyond BVES's service area. The cameras are located at selected mountain peaks, hill tops, and a radio station antenna. These locations were selected in partnership with UCSD, Big Bear Fire Department, San Bernardino Fire Department, San Bernardino Office of Emergency Services, and CAL FIRE.

*Resiliency of Sensor Communication Pathways*
HD Camera are connected through radio/cellular communication network connecting to UCSD's secured network protocols. UCSD monitors and maintains the connectivity of the HD cameras. Partnering with UCSD allows BVES to access and view the status of the cameras. BVES assists UCSD in maintaining the communications equipment and provides on-site checks when requested by UCSD.

*Integration of Sensor Data into Machine Learning or AI Software*
UCSD is piloting use of AI to improve alerts.

*Role of Sensor Data in Risk Response*
The HD cameras do not have sensor technology. HD Cameras provide continuous live feeds and employ AI technology which send alerts for potential smoke/fire locations and provide situational awareness allowing respective parties to better respond to alerts.

*False Positives Filtering*
Once BVES staff receive an alert notification, they view the cameras for situational awareness and determine what action is necessary on the part of BVES operational staff. If action is required, implementation of BVES operational response protocols would be taken. If no action is required, BVES would dismiss the alert.

Time between Detection and Confirmation
BVES does not keep records of alert notification from AI of a potential smoke/fire.

Security Measures for Network-Based
UCSD maintains and secures data feeds. HD cameras are accessible by BVES through the UCSD provided website, https://AlertCA.live which is available to the public.

**Infrared Cameras**

BVES does not have a separate infrared camera program. Infrared technology is being implemented in the AlertCalifornia HD camera system, which is described in above section "HD Video Cameras".

*General location of detection sensors (e.g., HFTD or entire service territory)*
15 cameras with infrared detection capability in 7 locations will provide full coverage and beyond BVES's service area. The cameras are located at selected mountain peaks, hill tops, and a radio station antenna. These locations were selected in partnership with UCSD, Big Bear Fire Department, San Bernardino Fire Department, San Bernardino Office of Emergency Services, and CAL FIRE.

*Highlight any improvements made since the last WMP submission*
Infrared technology is being implemented in ALERTCalifornia the camera system. BVES does not have a specific timeline for the infrared upgrades to the cameras.

*Resiliency of Sensor Communication Pathways*
The sensor communications pathways will be the same as discussed above in the "HD Video Cameras" section.

*Integration of Sensor Data into Machine Learning or AI Software*
BVES has not integrated the camera infrared detection into machine learning or AI software. UCSD will be pursuing the AI effort.

*Role of Sensor Data in Risk Response*
The infrared cameras will provide continuous live feeds and will send alert(s) for potential fire location and situational awareness allowing respective parties to better respond to the alert.

*False Positives Filtering*
When BVES staff receive an alert notification, they view the camera for situational awareness and determine what, if any, action is necessary by BVES operational staff. If action is required, implementation of BVES operational response protocols would be taken. If no action is required, BVES would dismiss the alert.

*Time Between Detection and Confirmation*
BVES does not maintain this data.

*Security Measures for Network-Based Sensors*
UCSD will maintain and secure data feeds.

**Fire Growth Potential Software**
*Summary*
In 2022, BVES began utilizing Technosylva's Wildfire Analyst Enterprise (WFA-E) wildfire forecasting application. This application includes FireCast and FireSim to simulate advanced fire spread and consequence modeling tools. BVES can run on-demand simulations at any points on a circuit to predict fire spread and consequence outputs such as fire perimeter size, structures impacted, and populations affected. This information assists in driving operational measures to mitigate wildfire including use of PSPS.

*General Location of Detection Sensors*

The graphic below illustrates the domain covered by the WFA-E model. It goes well beyond BVES's service area due to the potential for significant fire spread in the San Bernardino Mountains as a result of historical weather (winds, humidity), fuel levels, and topography.

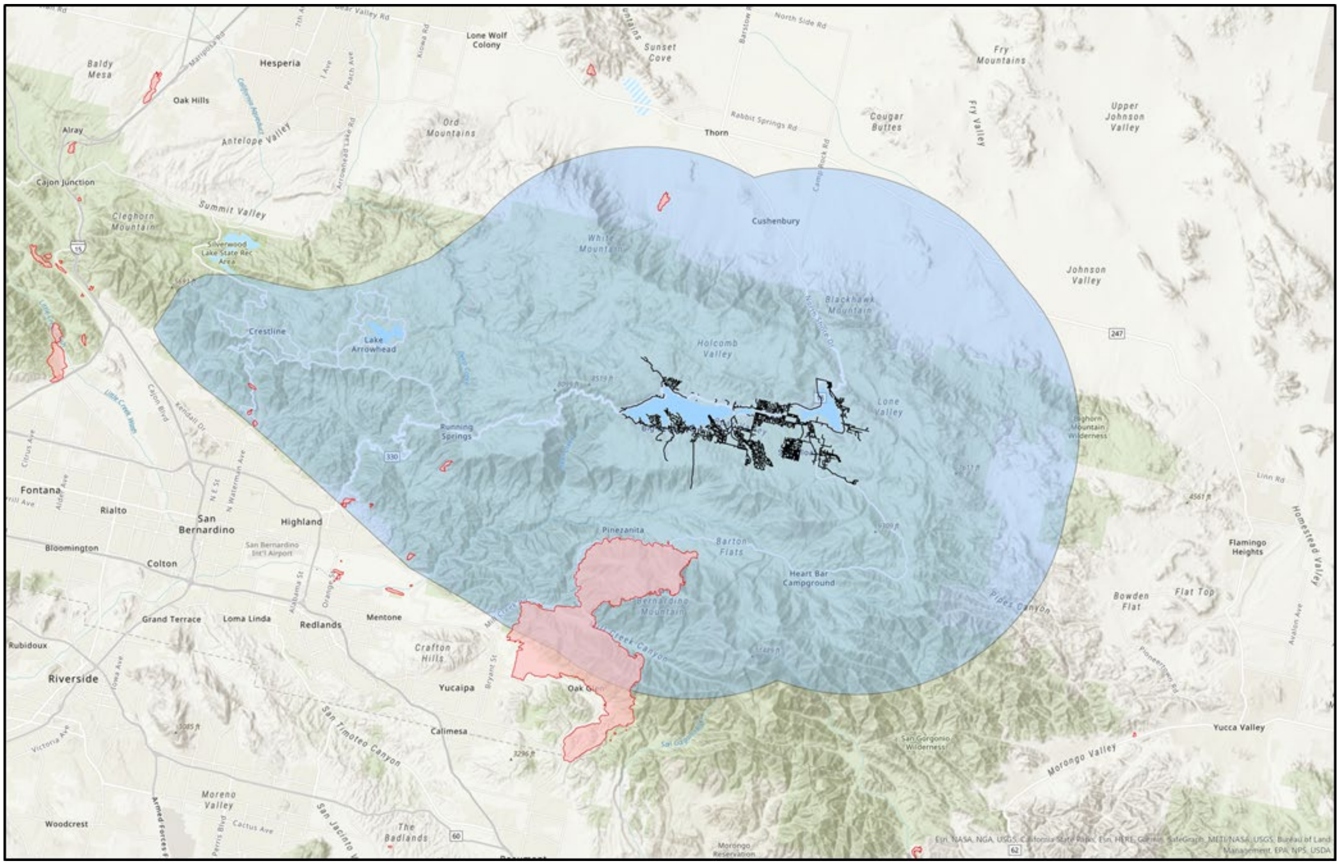


**Figure 8-5 WFA-E Domain Coverage**

*Resiliency of Sensor Communication Pathways*
N/A- Technosylva simulation software does not use sensors.

*Integration of Sensor Data into Machine Learning or AI Software*
N/A- Technosylva simulation software does not use sensors.

*Role of Sensor Data in Risk Response*
N/A- Technosylva simulation software does not use sensors.

*False Positives Filtering*
N/A- Technosylva simulation software does not use sensors.

*Time Between Detection and Confirmation*
N/A- Technosylva simulation software does not detect ignitions.

*Security Measures for Network-Based Sensors*
N/A- Technosylva simulation software does not use sensors.

### *8.3.4.2 Evaluation and Selection of New Detection Systems (WMSD_1)*

*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 (WMSD_1)*

*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 8-30 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 (WMSD_1)*

*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 (SAF_4)*

*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 forehcasts 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 (RMA_1)*

*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 focused weather forecasts, at least weekly, tailored to BVES's service area, and forecasts evaluating the prevailing fire threat.

Detail on the resources and datasets are as follow:

> Resources utilized for forecasting include a wide range of modeling data provided by NOAA, the National Weather Service, and the US Storm Prediction Center. All numerical weather prediction data is considered and ingested from the National Center for Environmental Predictions (NCEP), Canadian Meteorological Center (CMC) and European Centre for Medium-Range Weather Forecasts (ECMWF), utilizing all deterministic and ensemble models, including, but not limited to HRRR and RAP for short range guidance, NAM and GEM-RDPS for medium-range, and ECMWF, GFS and VFSv2 for longer-range data. Ensemble models consist of SREF & GEFS. Another dataset taken into consideration is the Deterministic Model Forecasts of IVT, IWV, and TIVT provided by the Center for Western Weather Water Extremes, Scripps Institution of Oceanography at UC San Diego.

Fire weather data, outlooks, and coordination are provided by the USFS along with the Southern California Geographic Coordination Center which includes hazardous outlooks from National Interagency Coordination Center and National Interagency Fire Center. All of the above data is considered when providing an accurate fire weather outlook and forecast for the San Bernardino Mountains and Big Bear Valley (BVES coverage area).

The meteorologist is able to obtain analysis of weather data before, during, and after certain extreme weather events. During elevated fire threat and storm conditions, the meteorologist provides forecasts at least daily. During a PSPS event, which BVES has not yet experienced, BVES's contracted meteorologist would provide near continuous forecasting.

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 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 8-32 FPI Features**

| Feature Group | Feature | Altitude | Description | Source | Update Cadence | Spatial Granularity | Temporal Granularity |
|---|---|---|---|---|---|---|---|
| See Statement Below | N/A | N/A | N/A | N/A | N/A | N/A | N/A |

BVES does not currently calculate FPI but plans to begin this calculation in 2023 and incorporate this measure into future WMP Updates. 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.*

BVES does not currently calculate FPI but plans to begin this calculation in 2023 and incorporate this measure into future WMP Updates. 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*

BVES does not currently calculate FPI but plans to begin this calculation in 2023 and incorporate this measure into future WMP Updates. 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 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)
- US 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 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. 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 EDRP 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 EDRP 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 Federal Emergency Management Agency (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 EDRP every year and update it as necessary. Figure 8-6 outlines the FEMA Six Step process.

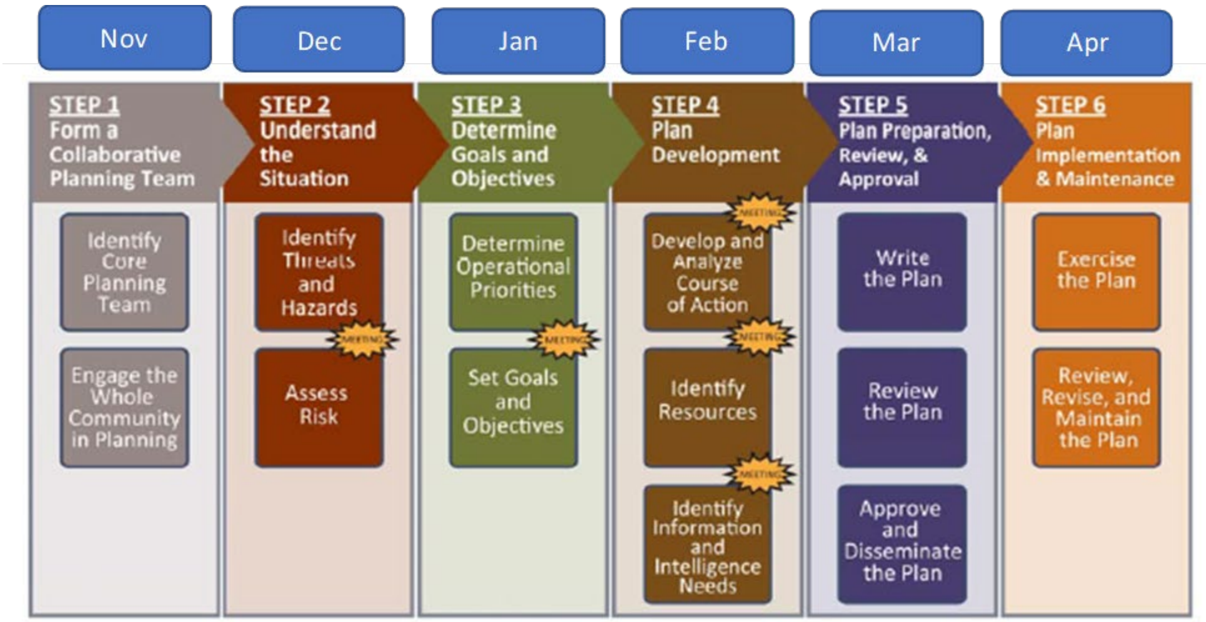



**Figure 8-6 FEMA National Planning System Six Step Process**

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.

BVES updated its 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 8-33 Emergency Preparedness 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) |
|---|---|---|---|---|---|
| Improve staff training on emergency and disaster response plan through a combination of classroom instruction, table-top exercises, and functional drills. | Emergency preparedness plan, EP_1 | GO 166 | Evaluate EDRP through FEMA Six Step review process. Continue to conduct training, exercises and drills | 31-Dec-25 | 8.4.2.1; pg. 268 |
| Increase coordination with community stakeholders in emergency response. | External collaboration and coordination, EP_2 | R.15-06-009 | Coordination meetings, exercises, and functional drills with community stakeholders | 31-Dec-25 | 8.4.3.1; pg. 300 |
| Develop robust lines and layers of communications with stakeholders and customers. | Public emergency communication strategy, EP_3 | R.15-06-009 | Coordination meetings, exercises, and functional drills with community stakeholders | 31-Dec-25 | 8.4.4.2; pg. 337 |
| Integrate plan to restore service after an outage due to a wildfire or PSPS event. | Preparedness and planning for service restoration, EP_4 | R.15-06-009 | Review plan to restore service after an outage due to a wildfire or PSPS event | 31-Dec-25 | 8.4.5; pg. 339 |
| Establish strong programs, systems, and protocols to support residential and non- residential customers in wildfire emergencies | Customer support in wildfire and PSPS emergencies, EP_5 | R.15-06-009 | Coordination meetings, exercises, and functional drills with residential and non-residential customers | 31-Dec-25 | 8.4.6; pg. 347 |

| 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) |
|---|---|---|---|---|---|
| and PSPS events. | | | | | |

*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 8-34 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<br>External collaboration and coordination, EP_2 | R.15-06-009 | Provide an updated plan which integrates the emergency response plan with the stakeholders, emergency response plan | 31-Dec-32 | 8.4.2.1; pg. 268<br>8.4.3.1; pg. 300 |
| Evaluate increased use of social media and technology to improve and streamline communications with stakeholders and customers. | Public emergency communication strategy, EP_3 | N/A | Evaluate the increased use of social media and modify use of social media based on findings | 31-Dec-32 | 8.4.4.2; pg. 337 |

*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 8-35 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 Emergency Plan | Yearly Review by FEMA Six-Step Process Completed in April 2023 | 3.62% | Yearly Review by FEMA Six-Step Process Completed by April 2024 | 3.62% | Yearly Review by FEMA Six-Step Process Completed by April 2025 | 3.62% | Annual Review Meeting |
| External collaboration and coordination | EP_2 | Meetings with Community Partners and Mutual Aid Groups | Meetings completed throughout the year | 3.62% | Meetings completed throughout the year | 3.62% | Meetings completed throughout the year | 3.62% | Records of Meetings with Community Partners and Mutual Aid Groups |
| Public emergency communication strategy | EP_3 | Review and Evaluate Emergency Program | Review and Evaluate Communication Strategy two times per year | 3.62% | Review and Evaluate Communication Strategy two times per year | 3.62% | Review and Evaluate Communication Strategy two times per year | 3.62% | Review Meetings |
| Preparedness and planning for service restoration | EP_4 | Review and Evaluate Emergency Program | Update Service Restoration Plan with Operations Group by June 2023 | 3.62% | Update Service Restoration Plan with Operations Group by June 2024 | 3.62% | Update Service Restoration Plan with Operations Group by June 2025 | 3.62% | Annual Revised Service Restoration Plan |

| 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 |
|---|---|---|---|---|---|---|---|---|---|
| Customer support in wildfire and PSPS emergencies | EP_5 | Review and Evaluate PSPS Program | PSPS Plan was reviewed and revised in January 2023 | 3.62% | Yearly Review and Evaluate PSPS Program completed by April 2024 | 3.62% | Yearly Review and Evaluate PSPS Program completed by April 2025 | 3.62% | Annual Review Meeting |

#### *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 8-36 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 (EP_1)*

*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 table-top 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.*

*The overview must be no more than six pages*

*In addition, the electrical corporation must provide a table with a list of current gaps and limitations in evaluating, developing, and integrating wildfire- and PSPS-specific preparedness and planning features into its overall emergency preparedness plan(s). Where gaps exist, the electrical corporation must provide a remedial action plan and timeline for resolving. Table 8-37 provides an exemplar of the minimum level of content and detail required for this information.*

BVES approach to wildfire and PSPS emergency preparedness is to utilize the BVES Emergency Disaster Response Plan (EDRP) and the BVES PSPS Policy and Procedures plan to effectively and efficiently respond to a loss of power including a proactive de-energization (PSPS event) or wildfire event impacting the BVES service area. BVES 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:

- Train staff on the BVES EDRP and the BVES PSPS Policy and Procedures Plan,
- Deploy wildfire response team(s) to high fire risk areas,
- Adjust protective device settings optimized for fire prevention (this is limited to adjusting the reclosing feature – automatic to manual),
- Increase frequency of consultant meteorologist forecast,
- Increase monitoring of Technosylva’s WFA-E and running fire spread simulations,
- Increase monitoring of weather stations, forecasts, and fire threat conditions,
- Increase communications with SCE points of contact,

- Proactively engage with first responders, local government and agencies, and other stakeholders,
- Proactively communicate with customers and other stakeholders,
- Identify Medical Baseline customers and AFN populations that may be impacted,
- Prepare to activate Community Resource Center (CRC),
- Activation of Emergency Operations Center (EOC) and EDRP,
- Prepare Bear Valley Power Plant for sustained operations,
- Conduct switch operations to minimize impact of potential PSPS activity,
- Engage temporary generation, and
- Activate CRC,
- Improvements/updates made since the last WMP submission.

The EDRP requires BVES's staff shall be organized largely based on the Standardized Emergency Management System (SEMS) as interpreted by the BVES. The SEMS structure utilized by BVES is a utility compatible Incident Command Structure (ICS) framework designed to manage emergency incidents and events.

SEMS is an emergency preparedness and response system endorsed by the State of California. It is the cornerstone of California's emergency response system and the fundamental structure for the response phase of emergency management. SEMS unifies all elements of California's emergency management community into a single integrated system and standardizes key elements. Additionally, it provides a common structure for all organizations responding to an emergency and a means of systematic planning. The benefits of using the SEMS include:

- Use of common terminology among agencies.
- Use of parallel organizational functions among agencies.
- Provides a standard means of systematic planning.

- The basic SEMS organization structure is shown in Figure 8-7, SEMS Organization:

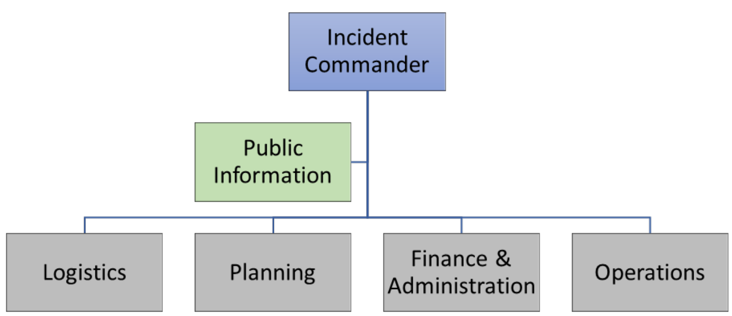



**Figure 8-7 SEMS Organization**

By organizing the response team along the SEMS structure, the BVES emergency response team coordinates with other government agencies via their corresponding groups. For example, BVES Operations coordinates directly with the City of Big Bear Lake EOC and San Bernardino County OES Operations Groups, as necessary. Additionally, when BVES sends a representative to these two centers, the representative brings a good understanding of the emergency response organization.

The organization chart presented below in Figure 8-8, BVES Emergency Organization, provides the BVES Emergency Organization structure for the full mobilization (Level 1) of BVES's staff in responding to emergencies per this plan. This organizational structure is intended to operate out of an EOC established by BVES and be sustainable for long-term emergency response activities. Due to the size and available resources, the structure BVES utilizes for emergency and PSPS events are the same. Also, the personnel utilized in both Emergency and PSPS events are also the same.

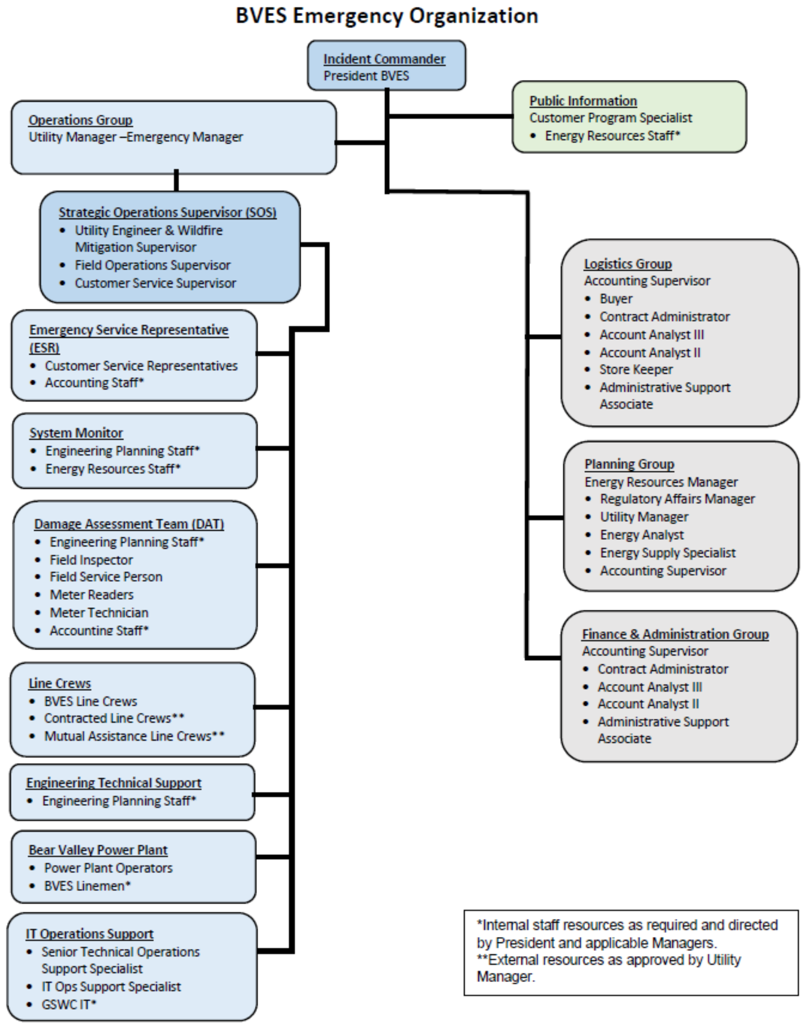



**Figure 8-8 BVES Emergency Organization**

There are three basic emergency response levels that BVES uses. Level 1 and 2 pertain to the EDRP and Level 3 refers the normal BVES working hours and afterhours Field Operations and Customer Service outage response procedures and processes. When the EDRP is activated, Level 1 or 2 are used to describe level of EOC activation and restoration response process. Level 3 is the normal Service Crew (or Dutyman for afterhours) response process to outages and system problems during the course of normal Transmission & Distribution operations. The response levels to outages and emergencies are summarized in BVES Table 8-10 below:

**BVES Table 8-10 Outage and Emergency Response**

| Response | Event Type | Action | Comments |
|---|---|---|---|
| **Level 1** | High Risk | EOC fully activated | |

| Response | Event Type | Action | Comments |
|---|---|---|---|
| | Long-term* | ERP processes implemented | It is preferred to fully activate EOC and then shift to Level 2 activation, if full response determined not necessary. |
| **Level 2** | Moderate Risk<br>Short-term | EOC partially activated<br>ERP processes implemented | Level of EOC activation and ERP implementation as directed by Utility Manager. |
| **Level 3** | Low Risk<br>Short-term | Normal Service Crew/Dutyman and Customer Service processes | These events are normally within the capability of assigned Service Crew or Dutyman to resolve with the normal on call resources. |

*Long-term is generally defined as 12 hours.

In the event of a wildfire, the following are flow charts for EDRP and PSPS events:

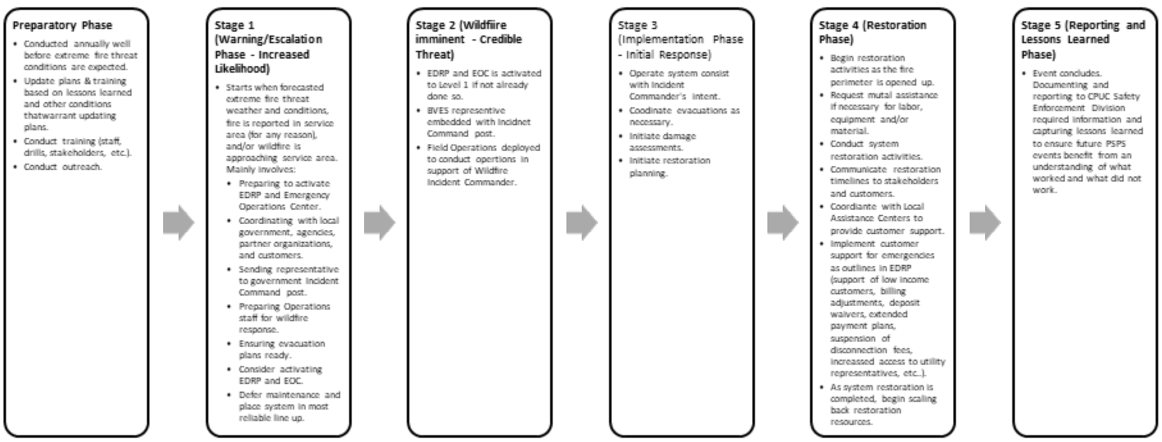



**Figure 8-9 EDRP Event Flowchart**

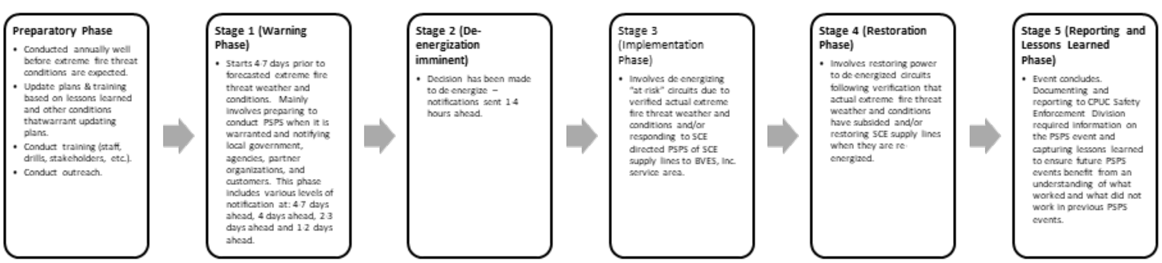



**Figure 8-10 PSPS Event Flowchart**

For PSPS training, BVES performs two drills per year which includes the public, stakeholders, CPUC, and OEIS involvement. One of the PSPS training is a table-top exercise and 2023 the other PSPS training in 2023 is a full-scale exercise. BVES also conducts at a minimum, two internal training sessions for PSPS.

For Emergency response, BVES conducts a minimum of one internal training session annually which is conducted by BVES' Health and Safety contractor. BVES reviews the EDRP annually utilizing the FEMA National Planning System 6-Step Process. BVES also staffs up its EOC at least once per year (real world event or, if none, then for training (drill scenario)). If an emergency or PSPS event takes place, BVES will review its performance and develop lessons learned. Training will be conducted to the appropriate personnel for lessons learned.

BVES assigns personnel for each task which matches their expertise. Examples are: the Incident Commander is the President, the Emergency Manager is the Utility Manager, and the Finance and Administration Group is led by the Account Supervisor. Refer to Table 8-38 Emergency Preparedness Staffing and Qualifications for the experience of BVES personnel.

**Table 8-37 Key Gaps and Limitations in Integrating Wildfire- and PSPS-Specific Strategies into Emergency Plan**

| Gap or Limitation Subject | Remedial Brief Description | Remedial Action Plan |
|---|---|---|
| Training | BVES continues to improve staff training and drills (exercises) based on real world incidents and lessons learned including those from other IOUs. | The training and exercise programs are continually updated and improve to incorporate new procedures and tools. In 2023, BVES is adding a full-scale PSPS exercise (in 2022 BVES performed a semi-functional exercise). |
| Coordination with outside organizations | BVES continues to seek to improve coordination with outside stakeholder organizations. | BVES training and exercise events will include outside stakeholder organizations to the maximum extent possible. |
| Post Action Reviews | After each PSPS exercise or real-world event, BVES collects and discusses lessons learned in order to develop areas for improvement. | Any change or update recommended in Post Action Reviews are to be added to the PSPS or emergency plan, if deemed appropriate, and training is conducted as necessary. BVES will focus on process updates to address any areas for improvement. |

### *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 8-38 provides an exemplar of the minimum level of content and detail required.*

**Table 8-38 Emergency Preparedness Staffing and Qualifications**

| Role | Incident Type | Responsibilities | Qualifications | # of Dedicated Staff Required | # of Dedicated Staff Provided | # of Contract Workers Required | # of Contract Workers Provided |
|---|---|---|---|---|---|---|---|
| President | Emergency or PSPS | 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 | N/A | N/A |
| Utility Manager | Emergency or PSPS | Direct emergency operations under the WMP and EDRP; Ensure monitoring of | -BS and PE Chemical Engineer<br>-10 years as environmental consultant conducting site inspections and project management | 1 | 1 | N/A | N/A |

| Role | Incident Type | Responsibilities | Qualifications | # of Dedicated Staff Required | # of Dedicated Staff Provided | # of Contract Workers Required | # of Contract Workers Provided |
|---|---|---|---|---|---|---|---|
| | | weather forecasts and conditions is conducted by staff;<br>Direct operational activities related to system line-up and PSPS as warranted;<br>Ensure Field Operations provide timely / accurate information to the Customer Service Supervisor and staff performing customer and public information functions;<br>Closely coordinate with stakeholders leading to a PSPS event, during PSPS, and during | involving a variety of environmental and safety issues<br>-13 years of experience in general management of industrial equipment used in hazardous areas | | | | |

| Role | Incident Type | Responsibilities | Qualifications | # of Dedicated Staff Required | # of Dedicated Staff Provided | # of Contract Workers Required | # of Contract Workers Provided |
|---|---|---|---|---|---|---|---|
| | | 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 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 | | | | | |

| Role | Incident Type | Responsibilities | Qualifications | # of Dedicated Staff Required | # of Dedicated Staff Provided | # of Contract Workers Required | # of Contract Workers Provided |
|---|---|---|---|---|---|---|---|
| | | 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 | Emergency or PSPS | Monitor (or direct monitoring) weather advisories, consultant forecasts, and the NFDRS Forecast at least daily during fire season; Direct and manage operational system line-ups | -Over 42 years in the utility industry<br>-Journeyman Lineman<br>-Power Troubleman<br>-Line Crew Foreman<br>-Operations Manager<br>-Assistant General Manager of Operations | 1 | 1 | N/A | N/A |

| Role | Incident Type | Responsibilities | Qualifications | # of Dedicated Staff Required | # of Dedicated Staff Provided | # of Contract Workers Required | # of Contract Workers Provided |
|---|---|---|---|---|---|---|---|
| | | based on conditions as described in PSPS Plan;<br>Direct and coordinate PSPS procedures;<br>Direct the activities of the WRT;<br>Control all switch and system line-up operations;<br>Provide (or ensure) timely / accurate information to the Customer Service Supervisor and/or staff performing customer / public information functions;<br>Inform the Utility Manager of system issues; | | | | | |

| Role | Incident Type | Responsibilities | Qualifications | # of Dedicated Staff Required | # of Dedicated Staff Provided | # of Contract Workers Required | # of Contract Workers Provided |
|---|---|---|---|---|---|---|---|
| | | Collect data and maintain documentation including, but not limited to, inspections, operational system line-up, and PSPS activities; and Submit to the Utility Manager recommended changes to PSPS Plan as warranted. | | | | | |
| Utility Engineer & Wildfire Mitigation Supervisor | Emergency or PSPS | 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; | -13 years as an Electrical Engineer<br>-Eight Years with BVES as substation designer, transmission/distribution designer and compliance engineer | 1 | 1 | N/A | N/A |

| Role | Incident Type | Responsibilities | Qualifications | # of Dedicated Staff Required | # of Dedicated Staff Provided | # of Contract Workers Required | # of Contract Workers Provided |
|---|---|---|---|---|---|---|---|
| | | Research, evaluate, and source materials fire resistant materials and equipment;<br>Develop device protective settings and select fuses to prevent fire while taking into account reliability and load;<br>Support Field Operations and the WRT as directed by the Utility Manager in the execution of system operations; and<br>Submit recommended changes to the Utility Manager as warranted. | | | | | |

| Role | Incident Type | Responsibilities | Qualifications | # of Dedicated Staff Required | # of Dedicated Staff Provided | # of Contract Workers Required | # of Contract Workers Provided |
|---|---|---|---|---|---|---|---|
| Customer Program Specialist | Emergency or PSPS | Notify (or direct to notify) local government, agency, and customer notifications; Establish and maintain customer communications methods and equipment to support PSPS 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; | - 25 years of energy and utility experience<br>-23 years working for BVES/Golden State Water Company in various roles such as: customer care and operations support superintendent, energy analyst, energy pre-scheduler, engineering technician, and customer support representative | 1 | 1 | N/A | N/A |

| Role | Incident Type | Responsibilities | Qualifications | # of Dedicated Staff Required | # of Dedicated Staff Provided | # of Contract Workers Required | # of Contract Workers Provided |
|---|---|---|---|---|---|---|---|
| | | Direct a customer education strategy to inform customers about BVES's fire mitigation programs including PSPS; and<br>Submit to the Utility Manager recommended changes to PSPS Plan as warranted. | | | | | |

## Personnel Training (GD_39)

*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 table-top 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.

## 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*

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 four 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 8-39 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 Provided with Training | Form of Verification or Reference |
|---|---|---|---|---|---|---|---|
| Fire Safety | Required fire safety training for all BVES staff | In-person or online for all training classes | As required, yearly, or every other year | All staff | ~ 45 | All staff will be scheduled for Fire Safety Training | Sign-in sheets used for all training classes |
| Office Safety | Required office safety training for all BVES staff | In-person or online for all training classes | As required, yearly, or every other year | All Staff | ~45 | All staff will be scheduled for Office Safety Training | Sign-in sheets used for all training classes |
| Ergonomics | Required ergonomics training for all BVES staff | In-person or online for all training classes | As required, yearly, or every other year | All Staff | ~45 | All staff will be scheduled for Ergonomics Training | Sign-in sheets used for all training classes |
| Emergency Action Plan | Required emergency action plan training for all BVES staff | In-person or online for all training classes | As required, yearly, or every other year | All Staff | ~45 | All staff will be scheduled for Emergency Action Plan Training | Sign-in sheets used for all training classes |

| Training Topic | Purpose and Scope | Training Method | Training Frequency | Position or Title of Personnel Required to Take Training | # of Personnel Requiring Training | # of Personnel Provided with Training | Form of Verification or Reference |
|---|---|---|---|---|---|---|---|
| Hazardous Communications | Train staff about proper comms during hazardous conditions<br>Required hazardous communication training for all BVES staff | In-person or online for all training classes | As required, yearly, or every other year | All Staff | ~45 | All staff will be scheduled for Fire Safety Training | Sign-in sheets used for all training classes |
| Heat/Cold Stress | Promote worker safety under hot/cold conditions<br>Required heat/cold stress training for all BVES staff | In-person or online for all training classes | As required, yearly, or every other year | All Staff | ~45 | All staff will be scheduled for Heat/Cold Stress Training | Sign-in sheets used for all training classes |
| Injury and Illness Prevention (I & IP) | Promote worker safety<br>Required injury and illness prevention training for all BVES staff | In-person or online for all training classes | As required, yearly, or every other year | All Staff | ~45 | All staff will be scheduled for I & IP Training | Sign-in sheets used for all training classes |

| Training Topic | Purpose and Scope | Training Method | Training Frequency | Position or Title of Personnel Required to Take Training | # of Personnel Requiring Training | # of Personnel Provided with Training | Form of Verification or Reference |
|---|---|---|---|---|---|---|---|
| Personal Protective Equipment (PPE) | Promote worker safety<br>Required PPE training for all field ops and management staff | In-person or online for all training classes | As required, yearly, or every other year | Field Operations and Management | ~20 | Field Operations and Management will be scheduled for PPE Training | Sign-in sheets used for all training classes |
| Tool Safety | Promote worker safety<br>Required tool safety training for all field ops and management staff | In-person or online for all training classes | As required, yearly, or every other year | Field Operations and Management | ~20 | Field Operations and Management will be scheduled for Tool Safety Training | Sign-in sheets used for all training classes |
| Trenching, Shoring, and Excavation | Promote worker and public safety<br>Required fire safety training for all field ops and management staff | In-person or online for all training classes | As required, yearly, or every other year | Field Operations and Management | ~20 | Field Operations and Management will be scheduled for Trenching, Shoring, and Excavation Training | Sign-in sheets used for all training classes |
| Confined Space Entry | Promote worker safety | In-person or online for all | As required, yearly, or | Field Operations | ~20 | Field Operations and Management will be scheduled | Sign-in sheets used for all |

| Training Topic | Purpose and Scope | Training Method | Training Frequency | Position or Title of Personnel Required to Take Training | # of Personnel Requiring Training | # of Personnel Provided with Training | Form of Verification or Reference |
|---|---|---|---|---|---|---|---|
| | Required confined space entry training for all field ops and management staff | training classes | every other year | and Management | | for Confined Space Training | training classes |
| Lockout/Tagout | Promote worker safety<br>Required lockout/tagout training for all field ops and management staff | In-person or online for all training classes | As required, yearly, or every other year | Field Operations and Management | ~20 | Field Operations and Management will be scheduled for Lockout/Tagout Training | Sign-in sheets used for all training classes |
| Electrical Safety | Promote worker safety<br>Required electrical safety training for all field ops and management staff | In-person or online for all training classes | As required, yearly, or every other year | Field Operations and Management | ~20 | Field Operations and Management will be scheduled for Electrical Safety Training | Sign-in sheets used for all training classes |
| Roadway Worker | Promote worker and public safety<br>Required roadway worker | In-person or online for all | As required, yearly, or every other year | Field Operations and Management | ~20 | Field Operations and Management will be scheduled | Sign-in sheets used for all |

| Training Topic | Purpose and Scope | Training Method | Training Frequency | Position or Title of Personnel Required to Take Training | # of Personnel Requiring Training | # of Personnel Provided with Training | Form of Verification or Reference |
|---|---|---|---|---|---|---|---|
| | training for all field ops and management staff | training classes | | | | for Roadway Worker Training | training classes |
| Traffic Control and Flagging | Promote worker and public safety<br>Required traffic control and flagging training for all field ops and management staff | In-person or online for all training classes | As required, yearly, or every other year | Field Operations and Management | ~20 | Field Operations and Management will be scheduled for Traffic Control and Flagging Training | Sign-in sheets used for all training classes |

**Table 8-40 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 |
|---|---|---|---|---|---|---|---|
| Please See Statement Above | N/A | N/A | N/A | N/A | N/A | N/A | N/A |

### *8.4.2.3 Drills, Simulations, and Table-top 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, table-top 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.*

**Table 8-41 Internal 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 |
|---|---|---|---|---|---|---|---|
| Discussion-based | Internal TTE | Test PSPS Capabilities | Annual | President, Field Operations Supervisor Utility Engineer & Wildfire Supervisor, Customer Program Specialist, Accounting Supervisor, Logistic Group Leader, & Others | N/A | N/A | Post-Season Report |

| 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 |
|---|---|---|---|---|---|---|---|
| | | | | as required | | | |
| Operations-based | Internal Functional Exercise | Test PSPS Capabilities | Annual | President, Field Operations Supervisor Utility Engineer & Wildfire Supervisor, Customer Program Specialist, Accounting Supervisor, Logistic Group Leader, & Others as required | N/A | N/A | Post-Season Report |

BVES conducted internal table-top and functional exercises for PSPS emergency events. These exercises required staff to participate in simulated PSPS events and administer the PSPS Plan and EDRP, as appropriate to familiarize staff with efforts to be taken during such emergencies. BVES will continue to administer such exercises and will consider setting goals of administering internal exercises in future WMPs in the future as necessary to ensure preparedness for emergencies.

**External Exercises**

BVES conducts at least one table-top 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 8-42 External Drill, Simulation, and Table-top 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 |
|---|---|---|---|---|---|---|---|
| Discussion-based | Table-Top | Wildfire and PSPS Preparation | Once per year | President, Field Operations Supervisor Utility Engineer & Wildfire Supervisor, Customer Program Specialist, Accounting Supervisor, Logistic Group Leader, & Others as required | N/A | N/A | Exercise reported to the CPUC |

| 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 |
|---|---|---|---|---|---|---|---|
| Operations-based | Functional Exercise | Wildfire and PSPS Preparation | Once per year | President, Field Operations Supervisor or Utility Engineer & Wildfire Supervisor, Customer Program Specialist, Accounting Supervisor, Logistic Group Leader, & Others as required | N/A | N/A | Exercise reported to the CPUC |

### *8.4.2.4 Schedule for Updating and Revising Plan (EP_1)*

*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 8-43.*

BVES has not identified any specific future improvements at this time. Each year the EDRP is reviewed 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 is completed, BVES will update its EDRP 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 EDRP every year and update it as necessary. Figure 8-11 outlines the FEMA Six Step process.

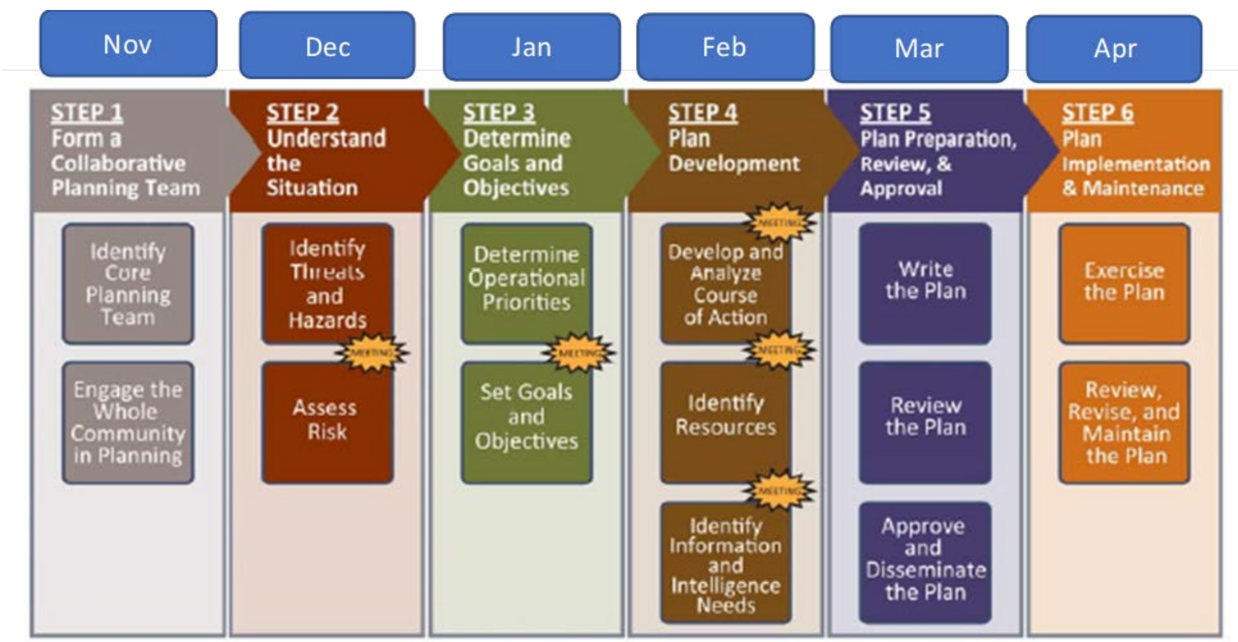



**Figure 8-11 FEMA National Planning System Six Step Process**

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 8-43 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 | Process change to align with roles and responsibilities | 8.4.2 |
| Public Safety Power Shutdown Plan dated January 31, 2023 | 2025 | Modification | None, no PSPS in territory | Annual plan revision | 9.1 |

## 8.4.3 External Collaboration and Coordination

### *8.4.3.1 Emergency Planning (EP_2)*

*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 an appendix:*

- *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.*

BVES staff is organized according to the California SEMS structure foremergency planning and response efforts. The SEMS structure utilized by BVES is the utility compatible Incident Command Structure (ICS) designed to manage emergency incidents and events. Roles and responsibilities during emergencies for all members within the BVES ICS are clearly defined. For example, BVES operations coordinates directly with the City of Big Bear Lake EOC or the San Bernardino County OES Operations Group during emergencies, as applicable. Refer to the EDRP, Appendix F, where the BVES SEMS organizational structure and emergency planning coordination efforts are defined and available for review.

BVES utilizes the iRestore Responder software application for emergency planning and coordinating efforts. The iRestore Responder application is a mobile-based emergency response system developed to aid first responsers in critical situations. The app was designed to provide effective and efficient communication between emergency responders and communication centers. The app expedites the emergency response time and coordinates emergency and remedial response activities between BVES personnel, public safety partners, and contractors who have been provided access to the app. iRestore's real-time insights into system damage provides BVES internal and external stakeholders better visibility of the incident and assists in restoration following a PSPS event.

BVES conducts and participates in annual emergency planning exercises and trainings. BVES conducted table-top and functional exercises in Q2 of 2022 where the EDRP procedures were tested. Additionally, BVES attended and participated in SCE's 2022 table-top and full-scale PSPS exercises. The lessons learned from the BVES and SCE-hosted exercises were incorporated into the BVES 2023 PSPS Plan. Additionally, BVES will host table-top and full-scale exercises in Q2 of 2023.

BVES also receives as needed assistance from various local government agencies through its mutual aid contract; please refer to Table 8-48 and Section 8.4.3.3 for details pertaining to the agreements established with local government agencies.

**Table 8-44 State and Local Agency Collaboration(s)**

| Name of State or Local Agency | Point of Contact and Information | Emergency Preparedness Plan Collaboration – Last version of Plan Agency Collaborated | Emergency Preparedness Plan Collaborative Role | Memorandum of Agreement (MOA) | Brief Description of MOA |
|---|---|---|---|---|---|
| CPUC | Drucilla Dunton<br>Sr. Regulatory Analyst<br>Drucilla.Dunton@cpuc.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Regulatory | N/A | N/A |
| San Bernardino County | Sbcoa@oes.sbcounty.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Big Bear Fire | Jeff Willis<br>Fire Chief<br>jeff.willis@bigbearfire.org | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Review and provide feedback regarding PSPS procedures | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| San Bernardino Fire | Dan Munsey<br>Fire Chief/Fire Warden<br>dmunsey@sbcfire.org | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Review and provide feedback regarding PSPS procedures | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| **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** |
|---|---|---|---|---|---|
| CAL FIRE | bdueccstaff@fire.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Review and provide feedback regarding PSPS procedures | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| US Forest Service | Travis.Mason@usda.gov | VM procedures dated October 6, 2021 | Review and provide feedback regarding VM procedures | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| San Bernardino County School District | rncollins@sbcsd.org | 2023 WMP PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Review and provide feedback regarding WMP | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| California Highway Patrol | Napoleon Salais<br>Sargent<br>NASalais@chp.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| California Department of Transportation | Emily Leinen<br>Public Information Officer<br>emily.leinen@dot.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Big Bear Area Regional Wastewater Agency | John Shimmin<br>Plant Manager<br>jshimmin@bbarwa.org | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Big Bear City Community Service Division | Mary Reeves<br>General Manager<br>mreeves@bbccsd.org | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| Big Bear Lake Department of Water and Power | Steve Wilson<br>Water Superintendent<br>swilson@bbldwp.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Big Bear Municipal Water District | Mike Stephenson<br>General Manager<br>mstephenson@bbmwd.net | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Bear Valley Community Healthcare District | John Mckinney<br>Public Information Officer<br>John.McKinney@bvchd.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| Bear Valley Unified School District | Dr. Mary Suzuki<br>Superintendent<br>mary_suzuki@bearvalleyusd.org | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Big Bear Chamber of Commerce | Ellen Clarke<br>Executive Director<br>execdir@bigbearchamber.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Big Bear Airport Authority | John Melissa<br>Maintenance Worker III<br>jmelissa@flybigbear.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| Big Bear Mountain Rescue | Mark Burnett<br>Sr. Director of Facilities<br>mburnett@bbmr.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Bear Valley Hospice | Lynda Boggie<br>Administrator<br>admin@bearvalleyhospice.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| AT&T | EM357C@att.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | No | N/A |

| 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 |
|---|---|---|---|---|---|
| City of Big Bear Lake | Sean Sullivan<br>Director of Public Services<br>ssullivan@citybigbearlake.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| City of Big Bear Lake | Jeff Mathieu<br>City Manager<br>Jmathieu@Cityofbigbearlake.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| San Bernardino Office of Emergency Services | Daniel Munoz<br>EMS Administrator<br>Daniel.Munoz@oes.sbcounty.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| Big Bear Fire | Mike Maltby<br>Assistant Chief<br>mmaltby@bigbearfire.org | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| CAL FIRE | BDUCommandStaff@fire.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| US Forest Service | Scott Evans<br>Utilities Coordinator<br>scott.a.evans@usda.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| San Bernardino County School District | Mitch Dattilo<br>Captain<br>mdattilo@sbcsd.org | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| California Highway Patrol | Jacob Griede<br>Public Information Officer<br>JGriede@chp.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Big Bear Area Water Authority | Troy Bemisdarfer<br>Plant Supervisor<br>tbemisdarfer@bbarwa.org | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| Big Bear Community Service District | Jerry Griffith<br>Water Department Superintendent<br>jgriffith@bbccsd.org | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Big Bear Lake Department of Water and Power | Jason Hall<br>Production Supervisor<br>jhall@bbldwp.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Big Bear Municipal Water District | Tim Bowman<br>Facility Manager<br>tbowman@bbmwd.net | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| Southwest Gas | Phillip Petteruto<br>District Manager<br>phillip.petteruto@swgas.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Bear Valley Community Healthcare Division | Megan Meadors<br>Program Director<br>megan.meadors@bvchd.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Bear Valley Unified School District | Linda Rosado<br>Executive Director of Business Services<br>linda_rosado@bearvalleyusd.org | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| Big Bear Airport Authority | Ryan Goss<br>General Manager<br>rgoss@flybigbear.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Big Bear Mountain Rescue | William Burke<br>Electrical Department Director<br>bburke@bbmr.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| Bear Valley Hospice | info@bearvalleyhospice.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| AT&T | RS4669@att.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | No | N/A |
| OEIS | Kevin Miller<br>Wildfire Safety Analyst<br>kevin.miller@energysafety.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Regulatory | N/A | N/A |
| OEIS | Melissa Semcer<br>Deputy Director<br>melissa.semcer@energysafety.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Regulator | N/A | N/A |

| 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 |
|---|---|---|---|---|---|
| Randle Communications | Noah Rodriguez<br>Assistant Account Manager<br>nrodriguez@randlecommunications.com | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Communications Contractor | N/A | N/A |
| CAL FIRE | Frank Bigelow<br>Assistant Deputy Director<br>frank.bigelow@fire.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| CAL FIRE | Jeff Fuentes<br>Battalion Chief,<br>Utility Fire Mitigation<br>jeff.fuentes@fire.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| California Office of Emergency Services | Patricia Utterback<br>Senior Emergency Services Coordinator<br>Patricia.Utterback@CalOES.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Regulatory | N/A | N/A |
| California Office of Emergency Services | Karen Valencia<br>Associate Government Program Analyst<br>karen.valencia@caloes.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Regulatory | N/A | N/A |
| California Office of Emergency Services | Michael Massone<br>Assistant Director, Response Operations<br>michael.massone@caloes.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Regulatory | N/A | N/A |

| 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 |
|---|---|---|---|---|---|
| California Office of Emergency Services | Thomas Graham<br>Regional Administrator<br>thomas.graham@caloes.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Regulatory | N/A | N/A |
| CAL FIRE | Stephen Volmer<br>State Fire Marshall<br>Stephen.Volmer@fire.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |
| CAL FIRE | Mark Hillskotter<br>Battalion Chief<br>Mark.Hillskotter@fire.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Exercise Participant | Mountain Mutual Aid | Refer to Section 8.4.3.3 |

| 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 |
|---|---|---|---|---|---|
| California Office of Emergency Services | Amanda Moyer<br>Emergency Services Coordinator<br>Amanda.Moyer@CalOES.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Regulatory | N/A | N/A |
| CPUC | Anthony Knoll<br>Program Manager<br>pspsnotification@cpuc.ca.gov | PSPS Plan dated January 31, 2023 and EDRP dated March 31, 2022 | Regulatory | N/A | N/A |

**Table 8-45 Key Gaps and Limitations in Collaboration Activities with State and Local Agencies**

| Gap or Limitation Subject | Remedial Brief Description | Remedial Action Plan |
|---|---|---|
| Not known at this time | N/A | N/A |

### *8.4.3.2 Communication Strategy with Public Safety Partners (COE_1)*

*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 8-46 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 | Email with read receipt. If email not read, then call | Quarterly Updates and Planned Exercises | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |

| 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 |
|---|---|---|---|---|---|---|
| Medical | Bear Valley Community Hospital | John P. McKinney MPT<br>Director of Physical Therapy/PIO<br>909-744-2231<br>John.mckinney@bvchd.com | Email with read receipt. If email not read, then call | Quarterly Updates and Planned Exercises | March 1, 2023 | N/A |
| | Bear Valley Hospice | Cary Stewart<br>949-338-7252<br>admin@bearvalleyhospice.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | N/A |
| Fire department | Big Bear Fire Department Headquarters – Station 281 41090 Big Bear Blvd | Jeff Willis<br>Fire Chief<br>909-731-4824<br>Jeff.willis@bigbearfire.org | Email with read receipt. If email not read, then call | Quarterly Updates and Planned Exercises | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |

| 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 |
|---|---|---|---|---|---|---|
| City & County Facilities | City of Big Bear Lake City Hall (includes Emergency Operations Center) | Erik Sund<br>City Manager<br>909-633-4011<br>sund@citybigbearlake.com | Email with read receipt. If email not read, then call | Quarterly Updates and Planned Exercises | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| Communications Providers | Verizon Wireless | Chris Sinner<br>714-669-3535<br>Chris.sinner@verisonwireless.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | | Jane Whang<br>415-778-1022<br>Jane.whang@verizon.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |

| 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 |
|---|---|---|---|---|---|---|
| | | Rex Knowles<br>801-514-0589<br>Rex.knowles@verizon.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | AT&T Wireless | Kevin Quinn<br>818-731-4000<br>Kq8185@att.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | | Joshua Overton<br>209-406-6712<br>Jo2147@att.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |

| 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 |
|---|---|---|---|---|---|---|
| | | Joshua Mathisen<br>Jm6547@att.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | | John Goddard<br>Jg266@att.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | Frontier California Inc. | Bret Plaskey<br>909-748-7880<br>Bret.p.plaskey@ftr.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |

| 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 |
|---|---|---|---|---|---|---|
| | | Charlie Born<br>916-686-3570<br>Charlie.born@ftr.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | Sprint | Jake Osorio<br>808-317-0276<br>SPR-inspections@motive-energy.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | Charter Communications | Robert Fisher<br>760-674-5404<br>Robert.fisher@charter.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |

| 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 |
|---|---|---|---|---|---|---|
| | | Lynn Notarianni<br>720-518-2585<br>Lynn.notariani@charter.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | | Dan Gonzalez<br>Dan.gonzales@charter.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | T-Mobile | Saif Abdullah<br>714-757-7075<br>Saif.abdullah@t-mobile.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |

| 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 |
|---|---|---|---|---|---|---|
| | | Steve Kukta<br>414-572-8358<br>Stephen.h.kukta@t-mobile.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| Radio Stations | KBHR | Cathy Herrick<br>909-499-4825<br>cathy@kbhr933.com | Email with read receipt. If email not read, then call | Quarterly Updates | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| Utilities | City of Big Bear Lake Department of Water | Danny Ent<br>909-816-7709<br>dent@bbldwp.com | Email with read receipt. If email not read, then call | Quarterly Updates and Planned Exercises | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |

| 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 |
|---|---|---|---|---|---|---|
| | Big Bear Area Regional Wastewater Agency (BBARWA) | John Shimmin<br>760-808-1256<br>jshimmin@bbarwa.org | Email with read receipt. If email not read, then call | Quarterly Updates and Planned Exercises | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | Big Bear City Community Services Department (CSD) | Mary Reeves<br>909-936-9521<br>mreeves@bbccsd.org | Email with read receipt. If email not read, then call | Quarterly Updates and Planned Exercises | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | Edison (SCE) | Bryan Falconer<br>Account Manager<br>626-826-3745<br>Bryan.falconer@sce.com | Email with read receipt. If email not read, then call | Quarterly Updates and External Planned Exercises | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |

| 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 |
|---|---|---|---|---|---|---|
| | Southwest Gas (SWG) | Phillip Petteruto<br>Superintendent Operations<br>909-366-4869<br>Phillip.petteruto@swgas.com | Email with read receipt. If email not read, then call | Quarterly Updates and Planned Exercises | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | | SWG Dispatch<br>877-860-6020<br>snvdispatch@swgas.com | Email with read receipt. If email not read, then call | Quarterly Updates and Planned Exercises | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |
| | Big Bear Municipal Water District (MWD) | Mike Stephenson<br>General Manager<br>909-289-5157<br>mstephenson@bbmwd.net | Email with read receipt. If email not read, then call | Quarterly Updates and Planned Exercises | March 1, 2023 | April 13, 2023, PSPS Table-top Exercise |

| 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 |
|---|---|---|---|---|---|---|
| Airports | Big Bear Airport District | John Melissa<br>909-904-7700<br>jmelissa@flybigbear.com | Email with read receipt. If email not read, then call | As Needed | N/A | April 13, 2023, PSPS Table-top Exercise |
| Schools | Bear Valley Unified School District | Dr. Mary Suzuki<br>Superintendent of schools<br>909-638-6851<br>Mary_suzuki@bearvalleyusd.org | Email with read receipt. If email not read, then call | As Needed | N/A | April 13, 2023, PSPS Table-top Exercise |
| Resorts | Big Bear Mountain Resorts | Mart Burnett<br>Sr. Director Facilities<br>909-725-4017<br>mburnett@bbmr.com | Email with read receipt. If email not read, then call | As Needed | N/A | N/A |

**Table 8-47 Key Gaps and Limitations in Communication Coordination with Public Safety Partners**

| Gap or Limitation Subject | Remedial Brief Description | Remedial Action Plan |
|---|---|---|
| Reliance on email communication | N/A | N/A |
| Lack of social media presence | N/A | N/A |
| AFN communication methodology | 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*

*Table 8-48 provides an exemplar of the minimum level of content and detail required.*

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 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 | Share information, resources, and manpower in case of an emergency | Information, manpower, and resources |

| | | |
|---|---|---|
| • City of Big Bear Lake<br>• Big Bear Fire Department<br>• San Bernardino County Fire<br>• San Bernardino County Department of Public Health<br>• San Bernardino County Office of Emergency Services (OES)<br>• San Bernardino County Sheriff's Department<br>• San Bernardino County Transportation Authority<br>• San Bernardino County Emergency Communications Service (ECS)<br>• US Forest Service<br>• California Highway Patrol<br>• California Department of Transportation<br>• Big Bear Airport<br>• Big Bear City Community Services District<br>• Big Bear Lake Department of Water & Power<br>• Big Bear Lake Municipal Water District<br>• Big Bear Area Regional Water Authority<br>• Bear Valley Electric Service, Inc.<br>• Southwest Gas<br>• Bear Valley Community Healthcare District<br>• Bear Valley Unified School District | | |

| **Mutual Aid Partner** | **Scope of Mutual Aid Agreement** | **Available Resources from Mutual Aid Partner** |
|---|---|---|
| • Mountain Area Regional Transit Authority<br>• Bear Mountain Ski Resorts<br>• Big Bear Chamber of Commerce<br>• Big Bear Lake Resort Association<br>• Big Bear Valley Recreation & Park District<br>• American Red Cross<br>• Big Bear Community Emergency Response Team (CERT)<br>• Big Bear Valley Community Organizations Active in Disaster (COAD)<br>• Big Bear Valley Voluntary<br>• Organizations Active in Disaster Resources available from the MAA partner | | |
| California Utilities Emergency Association (CUAE) | Share information, resources, and manpower in case of an emergency | Information, manpower, and resources |

## 8.4.4 Public Emergency Communication Strategy (EP_3)

*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 (COE_2)*

*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 Protocols for Emergency Communication to Public Stakeholder Groups**

| Stakeholder Group | Event Type | Method(s) for Communicating | Means to Verify Message Receipt |
|---|---|---|---|
| All Listed Above | All Listed Above | Email | Read Receipt<br>If read receipt not confirmed phone contact is made |

| Stakeholder Group | Event Type | Method(s) for Communicating | Means to Verify Message Receipt |
|---|---|---|---|
| State Agencies | PSPS Notifications<br>PSPS Restoration<br>Wildfire – Outage or Other Information<br>Wildfire – Repair & Maintenance Information | Email (preferred)<br>Voice & SMS (back up)<br>Website PSPS Portal | Read Receipt<br>If read receipt not confirmed phone contact is made |
| Public Safety Partners | PSPS Notifications<br>PSPS Restoration<br>Wildfire – Outage or Other Information<br>Wildfire – Repair & Maintenance Information | Email (preferred)<br>Voice & SMS (back up)<br>Website PSPS Portal | Read Receipt<br>If read receipt not confirmed phone contact is made |
| Critical facilities and Infrastructure | PSPS Notifications<br>PSPS Restoration<br>Wildfire – Outage or Other Information<br>Wildfire – Repair & Maintenance Information | Email (preferred)<br>Voice & SMS (back up)<br>Website PSPS Portal | Read Receipt<br>If read receipt not confirmed phone contact is made |
| Local governments | PSPS Notifications<br>PSPS Restoration<br>Wildfire – Outage or Other Information<br>Wildfire – Repair & Maintenance Information | Email (preferred)<br>Voice & SMS (back up)<br>Website PSPS Portal | Read Receipt<br>If read receipt not confirmed phone contact is made |
| First responders | PSPS Notifications<br>PSPS Restoration<br>Wildfire – Outage or Other Information<br>Wildfire – Repair & Maintenance Information | Email (preferred)<br>Voice & SMS (back up)<br>Website PSPS Portal | Read Receipt<br>If read receipt not confirmed phone contact is made |
| Tribal *governments – th*ere are no Tribal governments in BVES's service area. | N/A | N/A | N/A |
| Local media | PSPS Notifications<br>PSPS Restoration<br>Wildfire – Outage or Other Information<br>Wildfire – Repair & Maintenance Information | Email (preferred)<br>Voice & SMS (back up) | Read Receipt<br>If read receipt not confirmed phone contact is made |

| Stakeholder Group | Event Type | Method(s) for Communicating | Means to Verify Message Receipt |
|---|---|---|---|
| All customers including AFN and MBL | PSPS Notifications<br>PSPS Restoration<br>Wildfire – Outage or Other Information<br>Wildfire – Repair & Maintenance Information | Text Power (SMS), IVR (voice message), Website, Social Medial, | Text Power & IVR message delivery information available in system |
| General Public | PSPS Notifications<br>PSPS Restoration<br>Wildfire – Outage or Other Information<br>Wildfire – Repair & Maintenance Information | Website Updates, Social Media Updates, Press Releases | Website & Social Media visit data available |

BVES utilizes email to communicate to Public Stakeholder Groups. A "read receipt" is utilized to verify receipt of messages. If BVES does not receive a "Read Receipt" in a timely manner, we will contact the Stakeholder by phone. If the contact cannot be reached by phone, then the general contact number for the Stakeholder group will be called. It is critical for BVES to maintain an up-to-date Public Stakeholders Group list. Any out-of-date contact information can limit or delay communications with a Public Stakeholders.

Current gaps and limitations of Bear Valley's communication plan include:

- reliance on email,
- phone verification may be difficult, especially under emergency conditions,
- presence on social media needs improvement, and
- need to increase the messaging channels to AFN customers (mail, email, text, website, social media, radio ads, paper ads, etc.).

BVES will continue to develop the communications strategies to mitigate or eliminate the gaps listed above.

**BVES Table 8-11 Category Entity Primary Contact List**

| Category | Entity | Primary |
|---|---|---|
| Law enforcement | Sheriff's Department Big Bear Lake Patrol Station | Lt. Kelly Craig<br>Lieutenant<br>909-420-5620<br>kcraig@sbcsd.org |
| Medical | Bear Valley Community Hospital | John P. McKinney MPT<br>Director of Physical Therapy/PIO<br>909-744-2231<br>John.mckinney@bvchd.com |
| | Bear Valley Hospice | Cary Steward<br>949-338-7252<br>admin@bearvalleyhospice.com |

| Category | Entity | Primary |
|---|---|---|
| Fire Department | Big Bear Fire Department Headquarters- Station 281 41090 Big Bear Blvd | Jeff Willis<br>Fire Chief<br>909-731-4825<br>Jeff.willis@bigbearfire.org |
| City & County Facilities | City of Big Bear Lake City Hall (includes Emergency Operations Center) | Jeff Mathieu<br>Interim City Manager<br>909-633-1575<br>jeffmathieu@citybigbearlake.com |
| Communications providers | Verizon Wireless | Chris Sinner<br>714-669-3535<br>Chris.sinner@verizonwireless.com |
| Communications providers | Verizon Wireless | Jane Whang<br>415-778-1022<br>Jane.whang@verizon.com |
| Communications providers | AT&T Wireless | Kevin Quinn<br>818-731-4000<br>Kq8185@att.com |
| Communications providers | AT&T Wireless | Joshua Overton<br>209-406-6712<br>Jo2147@att.com |
| Communications providers | AT&T Wireless | Joshua Mathisen<br>Jm6347@att.com |
| Communications providers | AT&T Wireless | John Goddard<br>Jg266q@att.com |
| Communications providers | Frontier California Inc. | Bret Plaskey<br>909-748-7880<br>Bret.p.plaskey@ftr.com |
| Communications providers | Frontier California Inc. | Charlie Born<br>916-686-3570<br>Charlie.born@ftr.com |
| Communications providers | Sprint | Jake Osorio<br>818-317-0276<br>SPR-Inspections@motive-energy.com |
| Communications providers | Charter Communications | Robert Fisher<br>760-674-5404<br>Robert.fisher@charter.com |
| Communications providers | Charter Communications | Lynn Notarianni<br>720-518-2585<br>Lynn.notariani@charter.com |
| Communications providers | Charter Communications | Dan Gonzalez<br>Dan.gonzales@charter.com |
| Communications providers | T-Mobile | Saif Abdullah<br>714-757-7075<br>Saif.abdullah@t-mobile.com |
| Communications providers | T-Mobile | Steve Kukta<br>414-572-8358<br>Stephen.H.kukta@t-mobile.com |

| Category | Entity | Primary |
|---|---|---|
| Communications providers | T-Mobile | Vivek Kurisunkal<br>Vivek.kurisunkal@t-mobile.com |
| Radio stations | KBHR | Cathy Herrick<br>9099-499-4825<br>Cathy@kbhr933.com |
| Utilities | City of Big Bear Lake Department of Water | Danny Ent<br>909-816-7709<br>dent@bbldwp.com |
| Utilities | Big Bear Area Regional Wastewater Agency (BBARWA) | John Shimmin<br>760-808-1256<br>jshimmin@bbarwa.org |
| Utilities | Big Bear City Community Services Department (CSD) | Mary Reeves<br>909-936-9521<br>mreeves@bbccsd.org |
| Utilities | Edison (SCE) | Bryan Falconer<br>Account Manager<br>626082603745<br>Bryan.falconer@sce.com |
| Utilities | Southwest Gas (SWG) | Phillip Petteruto<br>Superintendent Operations<br>909-366-4869<br>Phillip.petteruto@swgas.com |
| Utilities | Southwest Gas (SWG) | SWG Dispatch<br>877-760-6020<br>snvdispatch@swgas.com |
| Utilities | Big Bear Municipal Water District (MWD) | Mike Stephenson<br>General Manager<br>909-289-5157<br>mstephenson@bbmwd.net |
| Airports | Big Bear Airport District | John Melissa<br>909-904-7700<br>jmelissa@flybigbear.com |
| Schools | Bear Valley Unified School District | Dr. Mary Suzuki<br>Superintendent of Schools<br>909-638-6851<br>Mary_suzuki@bearvalleyusd.org |
| Resorts | Big Bear Mountain Resorts | Mark Burnett<br>Sr. Director Facilities<br>909-725-4017<br>mburnett@bbmr.com |

### *8.4.4.2 Messaging (EP_3)*

*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.*

BVES's communications plan before, during and after a wildfire, an outage due to wildfire, or a PSPS event is designed develop effective messaging to reach the largest percentage of Public Stakeholders and includes the following elements:

**Pre-Incident Outreach and Education.** *A community that is knowledgeable and ready for emergency events will be a force multiplier in emergency response actions*.

BVES coordinates with local officials in compliance with Public Utilities Code section 768.6 and provides designated points of contact an opportunity to comment on draft and/or existing emergency plans.

BVES utilizes its website, social media, workshops, press releases, advertising, newsletters, bill inserts, two-way text communication, IVR, and other methods to provide information on emergency readiness preparation (including customer checklist for emergencies), backup generator safety information, reporting outages and emergencies, wire down event reporting/safety, PSPS, wildfire prevention measures, and outage restoration strategies. BVES maintains stakeholder contact lists, periodically briefs key elements on emergency plans at local stakeholder and public meetings and establishes strong working relationships with stakeholders. Stakeholders include at a minimum those listed in Section 8.4.1.

**Provide Emergency Incident Communications.** BVES believes achieving unity of effort provides for the most effective and efficient emergency response. This is best attained through the "4 C's" of disaster planning: (1) Collaboration, (2) Cooperation, (3) Coordination, and (4) Communication. During a wildfire or PSPS event, BVES strives to provide stakeholders, public and customers: extent of event, cause of the event, and estimated time of restoration. This information is provided at the start of the event, updated when new information is available, at a minimum every 2-3 hours during the event, and upon restoration from the event.

BVES strive to provide stakeholders, customers, and the public with reliable emergency notifications such that correct expectations are set and trust is developed. BVES develops consistent and accurate communications (if incorrect information is issued, a correction is issued and qualifies or avoids providing uncertain information). BVES establishes internal processes to ensure required regulatory notifications are made in a timely manner.

BVES keeps local officials and other key stakeholders informed of emergencies, which is critical to their ability to operate and support their missions. BVES utilizes standard press statement templates with fill-in-the-blank sections to update customers and the public with the "who, where, why, what, when, and how" to the emergency event. Short IVR and text messages are used to refer customers to additional resources (e.g., website or social media). BVES proactively engages media to reach a wide audience to convey correct information to the public.

BVES maintains "call center metrics" that measure customer access to information during an event and uses multiple channels to reach targeted audiences and issues alerts in English, Spanish, Chinese (including Cantonese, Mandarin and other Chinese languages), Tagalog, Vietnamese, Zapateco, and Mixteco.

**Post Emergency Event Close-out Statement.** Once the emergency event passes, BVES prepares a summary press release providing customers and stakeholders a summary of the event and instructions such as: how to contact BVES to reconnect service and repair damaged equipment and how to obtain additional post incident customer support.

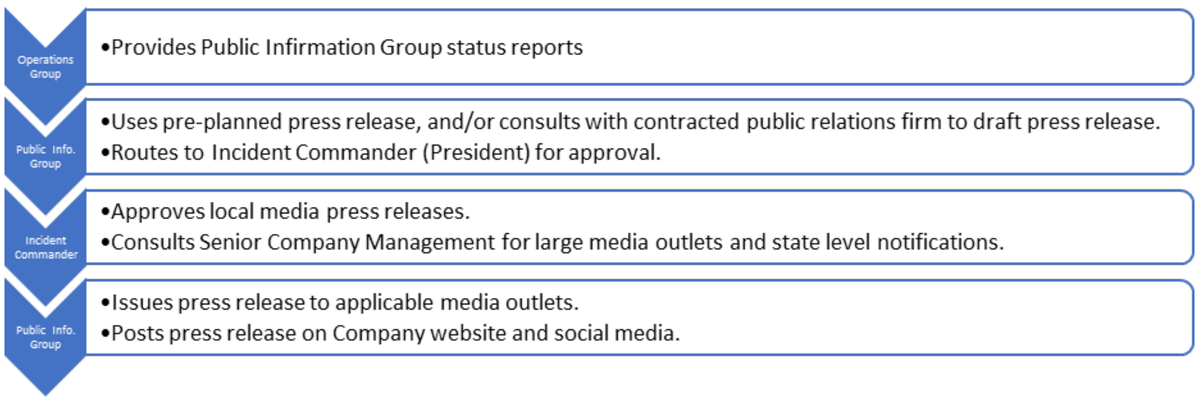



**Figure 8-12 BVES Press Release Protocol**

### *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 8-50 Key Gaps and Limitations in Public Emergency Communication Strategy**

| Gap or Limitation Subject | Remedial Brief Description | Remedial Action Plan |
|---|---|---|
| Reliance on email communication | N/A | N/A |
| Lack of social media presence | N/A | N/A |
| AFN communication methodology | N/A | N/A |

## 8.4.5 Preparedness and Planning for Service Restoration

### *8.4.5.1 Overview of Service Restoration Plan (EP_4)*

*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 table-top 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.*

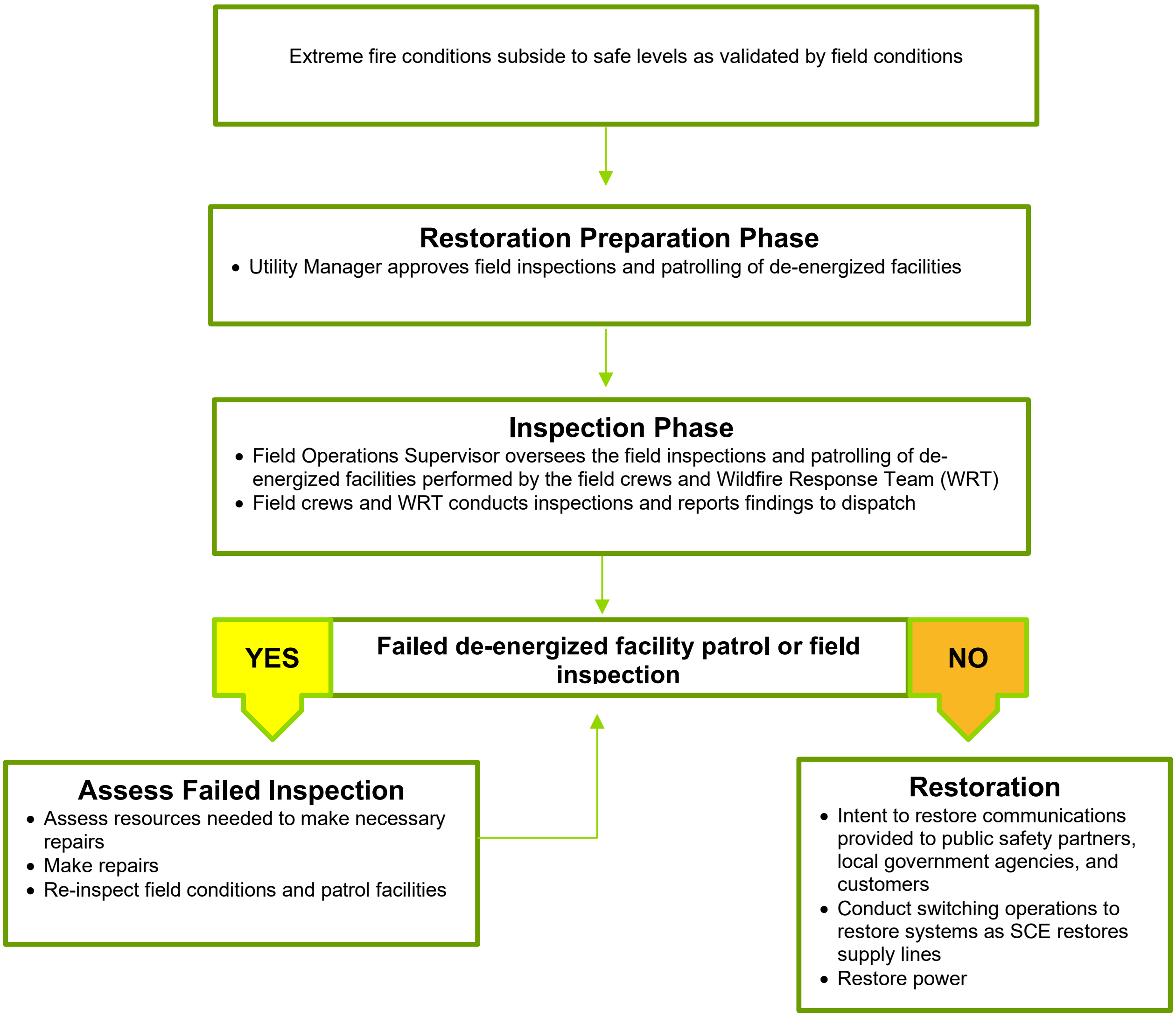
BVES recognizes the importance of establishing service restoration procedures and protocols. BVES's methodology for assessing conditions, prioritizing decisions, and allocating resources (staff and equipment) are defined in the BVES EDRP, located in Appendix F. BVES's EDRP complies with the requirements set forth in the General Order No. 166, Standards for Operation, Reliability, and Safety during Emergencies and Disasters.

Promptly assembling the Emergency Operations Center (EOC) is a crucial aspect of BVES's EDRP. The EOC is the central command and control facility responsible for carrying out the EDRP principles of emergency preparedness and emergency response functions during emergency events. The Utility Manager is responsible for ensuring the EOC provides support to BVES regarding strategic direction, operational decisions, and restoration activities. The EOC also collects and analyzes data to assess emergency response and prioritize decisions.

Leading up to a PSPS event, during a PSPS event, and during the PSPS restoration period, the Emergency Response Communications Plan of the EDRP is implemented in conjunction with the BVES PSPS Plan. Please refer to Appendix B and C of the BVES PSPS Plan where resource planning, public safety partner collaboration, and customer communication protocols during emergency events are discussed in detail.

During a PSPS event, if there is a downgrade in wildfire risk and wind speeds in the affected area drop below 50 mph for a period of 20 minutes, crews begin assessing the fire weather conditions. If the crew determines the fire weather conditions have subsided to "safe levels", BVES will begin the restoration of de-energized circuits. However, the crews will extend the calm period beyond 20 minutes, if further gusts of greater than 50 mph are likely based on their direct observation of local conditions or forecasts. Restoration activities which occur prior to re-energization include:

1. Validating that the extreme fire weather conditions have subsided to safe levels.
2. Conducting field inspections and patrols of facilities that were de-energized.
3. Repair of any identified immediate hazards (Level 1 inspection conditions).
4. Re-energization of inspected circuits.




**BVES Figure 8-6: Service Restoration Procedures**

A comprehensive template outlining the communications plan for notifying public safety partners during a potential PSPS activation can be found in BVES PSPS Plan. Developing communication and notification procedures is a collaborative effort across public safety partners and local jurisdictions, although BVES is ultimately responsible and accountable for the safe deployment of PSPS activations and restoration activities. BVES has coordinated with emergency responders, fire, and local governments to seamlessly integrate communication protocols with a goal of providing secondary notices as warranted.

### *8.4.5.2 Planning and Allocation of Resources (EP_1)*

*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*

- Before season starts, BVES plans and allocates resources to respond wildfires or PSPS events:
  - Establishes emergency contracts for essential restorative services.
  - Reviews and ensures mutual assistance agreements are sufficient.
  - Conducts outreach with stakeholders and customers to prepare for emergencies.
  - Builds up on site contingency inventories of materials.
  - Conducts training on EDRP and PSPS Procedures through table-top exercises and drills.
  - Ensures staff is sufficient to provide immediate response and plans.

- If there is a wildfire or conditions are approaching PSPS thresholds, BVES will enact their Public Safety Power Shutoff Plan (*BVES INC 2023 PSPS Procedures Final 022623*) and Table 5-1. The plan includes specific weather references including:
  - Frequently review weather and threat assessments.
  - Review Technosylva's WFA-E and conduct fire spread simulations at high-risk spots.
  - Notify meteorology consultant to provide more frequent forecasts.
  - Frequently monitor BVES installed weather stations.
  - Monitor local wind gusts in "at risk" areas.

There are three outage response levels at BVES. Level 1 and 2 pertain to the EDRP and are used to describe EOC activation and restoration responses. Level 3 refers the normal BVES working hours and afterhours Field Operations and Customer Service outage response procedures during normal T&D operations. The response levels are:

- 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.

When BVES activates the EDRP, the EOC is also activated. BVES leadership considers the following in evaluating whether to implement the EDRP and to what Level to activate the EOC:

- Will resources beyond BVES' normal outage response posture be required and to what extent? Will external resources (mutual aid /or contracted services be required)?
- Will the restoration efforts be long-term (generally >12 hours)? If long-term, how long?
- Will around the clock Customer Service and Field Operations be needed?
- Will restoration efforts require management/logistics support beyond Field Operations Supervisor?
- Is the outage (or potential outage) expected to significantly impact on BVES customers?

- Depending on the situations, the response level is established, and priorities are set. If reports concerning unsafe conditions increase, the response level will be increased, and additional help will be activated. In most cases resources shall be dispatched to restore systems to achieve the following restoration priorities:

- **Public safety** in the affected areas;
- **Worker safety** in performing the restoration work;
- **Critical infrastructure** key City & County facilities, other utility facilities (water, sewage, gas, communications), Airport, Traffic Control, Incident Commander Site, Incident Base Camp, Incident Evacuation Centers, communications providers, radio stations;
- **Continuity of community services** Major commercial activities critical to the community e.g., gas stations, food stores, lodging for first responders, financial institutions;
- **Medical Baseline Customers** and **Access and Functional Needs Customers**
- **Number of customers** affected; and
- **Length of time** customers have been without power.

When directing restoration efforts, the Operations Group shall prioritize restoring the following types of facilities in the prescribed order to optimally restore electric service:

- Energy supply sources
    - Sub-transmission circuits (34.5 kV)
    - Substations
    - Distribution circuits (4 kV)
    - Feeders
    - Distribution transformers
    - Individual Customer Service lines

The following table provides guidance on restoration priorities in the event of a wildfire or PSPS.

**BVES Table 8-12 Restoration Priorities Guidance**

| Priority | Sub-Transmission Circuit | Substation | Distribution Circuit | | Comments |
|---|---|---|---|---|---|
| **1** | Baldwin | Meadow | Garstin | | • Key critical infrastructure<br>• Connects BVPP |
| **2** | Shay/Radford | Pineknot<br>Village<br>Maltby<br>Division | Interlaken<br>Boulder<br>Harnish<br>Country Club | Georgia<br>Paradise<br>Erwin Lake<br>Castle Glen | • Additional critical infrastructure<br>• Major commercial activities & airport<br>• Large number of residential customers. |
| **3** | NA | Moonridge<br>Maple<br>Bear City<br>Fawnskin<br>Palomino | Eagle<br>Lagonita<br>Fox Farm<br>Clubview<br>Sunset | Goldmine<br>Holcomb<br>Pioneer<br>Sunrise | • Mostly residential customers |

| Priority | Sub-Transmission Circuit | Substation | Distribution Circuit | | Comments |
|---|---|---|---|---|---|
| **4** | NA | Bear Mountain<br>Summit Lake | Geronimo<br>Skyline | Lift<br>Pump House | • Mostly interruptible customer. |

- Establishing a multi-layered communications plan utilizing many separate communications channels is essential to ensuring that the communications plan shall be effective in reaching targeted audiences under uncertain and severe conditions, as would be expected for major outages and disasters and/or following such events. For example, some customers may lose their landline capability in a power outage but still have cell phone service. Plan resiliency is therefore dependent on having many overlapping layers of communications.

#### *8.4.5.3 Drills, Simulations, and Table-top 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, table-top 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, table-top 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 exemple of the minimum acceptable level of information is provided in Table 8-51.*

**Table 8-51 Internal Drill, Simulation, and Table-top 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 |
|---|---|---|---|---|---|---|---|
| Discussion-based | Table-top | Wildfire and PSPS Preparation | Once per year | President, Utility Manager, Field Operations Supervisor, Utility Engineer & Wildfire Supervisor, Customer Program Specialist, Accounting Supervisor, Logistic Group Leader, Others as required | 8 | 8 | Exercise reported to the CPUC |

### 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, table-top 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, table-top 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 table-top 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 8-52 External Drill, Simulation, and Table-top 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 |
|---|---|---|---|---|---|---|---|
| Discussion-based | Table-top | Wildfire and PSPS Preparation | Once per year | President, Utility Manager, Field Operations Supervisor, Utility Engineer & Wildfire Supervisor, Customer Program Specialist, Accounting Supervisor, Logistic Group Leader, Others as required | 12 | 14 | Exercise reported to the CPUC |
| Operations-based | Functional | Wildfire and PSPS Preparation | Once per year | President, Utility Manager, Field Operations Supervisor, Utility Engineer & Wildfire Supervisor, Customer | 12 | 14 | Exercise reported to CPUC |

| Category | Exercise Type | Purpose | Exercise Frequency | Position of Title of Personnel Required to Participate | Personnel Required | Personnel Completed | Form of Verification or Reference |
|---|---|---|---|---|---|---|---|
| | | | | Program Specialist, Accounting Supervisor, Logistic Group Leader, Others as required | | | |

### 8.4.6 Customer Support in Wildfire and PSPS Emergencies *(EP_5 - COE_1 – COE_2 – COE_3 – COE_4)*

*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.*

In the event of a major emergency, BVES has a dedicated customer support team to help impacted customers by providing information on available resources. All customer inquiries during major emergencies, such as wildfire, are prioritized. BVES's efforts to reach, engage and support AFN communities, including by developing partnerships with CBOs and providing for AFN needs at CRCs, can be found in BVES's AFN Plan Quarterly Update reports and the AFN Plan filed on January 31, 2023.

All customer inquiries during major emergencies, such as wildfire, are prioritized. During an emergency BVES attempts to reach, engage, and support AFN communities as well as the Functional Needs Populations. BVES has programs available to customers to help them through emergencies. BVES continues to improve communications to promote awareness and provide access to information and resources needed to mitigate the safety and economic impacts. BVES provides the following programs to deliver customer support during wildfire and PSPS emergencies: outage reporting, support for low-income customers, billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, repair processing and timing, list and description of community assistance locations and services, medical baseline support services, and access to electrical corporation representatives. These programs are further described below:

- Outage reporting – BVES uses best practices to provide customers with the most up-to-date information regarding outages and emergency communications, and to provide resources for reporting outages. 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 (Appendix F Sections 5.4 and 6.8). BVES provides multi-layered customer outreach communication programs including automated calls (IVR), automated text messages (Text Power), social media, email alerts, radio announcements, press releases, and updates on its website. The Operations Group is tasked with providing the Public Information Group, as a top priority, the following information regarding outages due to wildfire or PSPS: (1) extent of the outage including number of customers affected; (2) cause of the outage (if known) and status of BVES response (e.g., crews on site investigating, crews on site conducting repairs, etc.); (3) estimated time to restore (ETR) power – this must be updated and not allowed to go stale (e.g., ETR time passes without an update. The Public Information Group is responsible for updating local government, first responders, other community stakeholders, and customers including AFN and MBL customers with this information. Additionally, once power is restored, this must be communicated to the Public Information Group so that they can update local government, first responders, other community stakeholders, and customers including AFN and MBL customers.

- Support for low-income customers – To support for low-income customers BVES offers qualifying customers discounted rates on their electricity bill through California Alternate Rate for Energy (CARE) program. 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. The Customer Care Team shall freeze accounts in these programs and stop billing during the disaster event to ensure bills are not estimated or generated for affected customers. Billing shall resume once the case is closed by the Customer Care & Billing (CC&B) technical team, upon notice from the Supervisor.
- Billing adjustments – The Customer Care Team shall freeze accounts and stop billing during the disaster event to ensure bills are not estimated or generated for affected customers. Billing shall resume once the case is closed by the Customer Care & Billing (CC&B) technical team, upon notice from the Supervisor.
- Deposit waivers – The Customer Care Team shall add a designated customer contact for all affected customers. The contact shall reside within CC&B for up to one year from the date the emergency ends. This allows BVES to track the customer's account, so when service is restored, the utility knows to waive any associated fees and to expedite customer reconnection.
- Extended payment plans – The Customer Care Team shall freeze all payments on affected customers' account to avoid affecting their credit. All affected customers are notified that an extended payment plan option is available for any past due payments.
- Repair processing and timing – During emergencies, BVES shall set up specialized repair teams to expedite repair processing. If additional support is needed, BVES will leverage mutual aid programs with other emergency response resources and work with electrical contractors to ensure timely service restoration. This is covered in Section 6.6 of BVES's EDRP (Appendix F)
- List and description of community assistance locations and services – BVES provides outreach to inform customers of available community assistance. BVES provides the information on its website, outreach to its Community Based Organization's (CBO), advertisements through social media, outreach to mobile home park managers, and bus stop ads. During PSPS events, BVES uses Community Resource Centers to provide support to customers in areas most likely to experience shutoffs. These locations

provide customers with water, light snacks and, access to restrooms and Wi-Fi. Customers can also obtain updated outage information, sign up for alerts, update their contact information and charge their personal mobile and certain portable medical devices.

- Medical Baseline support services – BVES updates the current list of medical baseline and AFN customers bi-monthly. This information is distributed internally, and the list is on the PSPS portal for critical facilities to access if needed. BVES also will provide automated calls, texts, emails, or door tags depending on the emergency. This program provides customers electricity at a discounted rate, helping to reduce monthly utility costs. Medical Baseline customers receive additional program eligibility for BVES's Critical Care Backup Battery Program. This program supports customers' ability to utilize their medical equipment in the event of an outage, including an outage caused by a PSPS event or a wildfire. BVES also works with regional agencies and partners to support customer needs before and during PSPS events. Additionally, enrollment as a Medical Baseline customer adds protections during PSPS activations and prior to disconnections through an escalated notification process.
- Access to electrical corporation representatives BVES representatives are available by phone on a 24-hour basis during an emergency. BVES regularly provides updated emergency information to the local radio station and press. 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. BVES may direct staff and resources to county and local government assistance centers during disasters or PSPS events to provide in-person support.

## 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 8-53 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 | GO 166 | Evaluate effectiveness of outreach efforts and adjust outreach efforts based on evaluation results | 31-Dec-25 | 8.5.2; pg. 344 |

| 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 improve program to understand, evaluate, design, and implement wildfire and PSPS risk mitigation strategies, policies, and procedures specific to AFN customers. Evaluate effectiveness of these efforts. | Engagement with access and Functional Needs Populations, COE_2 | GO 166 | Evaluate effectiveness of efforts with AFN customers and adjust efforts based on evaluation results | 31-Dec-25 | 8.5.3; pg. 348-350 |
| 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 | GO 166 | Evaluate effectiveness of collaborating with communities on local wildfire mitigation plans and adjust outreach efforts based on evaluation results | 31-Dec-25 | 8.5.4; pg. 351 |

| 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 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 | GO 166 | Attend electrical corporation workshops that share best practices of WMP programs | 31-Dec-25 | 8.5.5; 353-356 |

**Table 8-54 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 | GO 166 | Evaluate effectiveness of increased public outreach and education awareness program(s) and adjust outreach efforts based on evaluation results | 31-Dec-25 | 8.5.2; pg. 344 |
| Establish streamlined routine for sharing lessons learned and best practices among peers. | Best practice sharing with other utilities, COE_4 | GO 166 | Attend electrical corporation workshops that share best practices | 31-Dec-25 | 8.5.5; pg. 353-356 |

### *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 8-55 Community Outreach and Engagement Initiative Targets by Year**

| 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 |
|---|---|---|---|---|---|---|---|---|
| Collaboration on local wildfire mitigation planning | COE_3 | Develop Program | 3.62% | Review and Maintain Program | 3.62% | Review and Maintain Program | 3.62% | Version History |
| Best practice sharing with other utilities | COE_4 | Work Groups, Conferences | 3.62% | 15 | 3.62% | 15 | 3.62% | Quantitative |

**Table 8-56 PSPS Outreach and Engagement Initiative Targets by Year**

| Initiative Activity | Tracking ID | Target End of Q2 2023 & Unit | Target End of Q3 2023 & Unit | End of Year Target 2023 & Unit | X% Risk Impact 2023 | Target End of Q2 2024 & Unit | Target End of Q3 2024 & Unit | End of Year Target 2024 & Unit | X% Risk Impact 2024 | Target 2025 & Unit | X% Risk Impact 2025 | Method of Verification |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Public outreach and education awareness program | COE_1 | 180 | 270 | 360 | 3.62 % | 180 | 270 | 360 | 3.62 % | 360 | 3.62 % | Quantitative |
| Engagement with access and Functional Needs Populations | COE_2 | 6 | 9 | 12 | 3.62 % | 6 | 9 | 12 | 3.62 % | 12 | 3.62 % | Quantitative |

### *8.5.1.3 Performance Metrics Identified by BVES*

For each performance metric listed in Table 8-57, BVES reports its performance since 2022, projected performance for 2023-2025, and the method of verification. Trends in performance are unavailable at this time due to the lack of historical data. BVES began tracking performance metrics for community outreach and engagement events in 2022 and will begin tracking AFN customer verifications in 2023. BVES will report on trends in future WMPs.

**Table 8-57 Community Outreach and Engagement Performance Metrics Results by Year**

| Performance Metrics | 2020 | 2021 | 2022 | 2023 Projected | 2024 Projected | 2025 Projected | Method of Verification (e.g., third-party verification, WMP) |
|---|---|---|---|---|---|---|---|
| Public outreach and education events | N/A | N/A | 250 | 360 | 360 | 360 | Third-party QDR verification |
| AFN customer verifications | N/A | N/A | N/A | 12 | 12 | 12 | Third-party QDR verification |

## 8.5.2 Public Outreach and Education Awareness Program (COE_1 – COE_2 – COE_3 – COE_4)

*The electrical corporation must provide a high-level overview of its public outreach and education awareness program(s) for wildfires; outages due to wildfires, PSPS events, and protective equipment and device settings; service restoration before, during, and after the incidents (as required by Public Utilities Code section 8386[c][19][B]); and vegetation management. This includes outreach efforts in English, Spanish, Chinese (including Cantonese, Mandarin, and other Chinese languages), Tagalog, and Vietnamese, as well as Korean and Russian where those languages are prevalent within the service territory.*

*At a minimum, the overview must include the following:*

- *A description of the purpose and scope of the program(s).*
- *References to the Utility Initiative Tracking ID where appropriate.*
- *A brief narrative followed by a tabulated list of all the different target communities it is trying to reach across the electrical corporation's service territory. The target communities list must include AFN and other vulnerable or marginalized populations, but they may also include other target populations, such as communities in different geographic locations (e.g., urban areas, rural areas), age groups, language and ethnic groups, transient populations, or Medical Baseline customers. In addition, the electrical corporation must summarize the interests or concerns each community may have before, during, or after a wildfire or PSPS event to help inform outreach and education awareness needs. Table 8-58 provides an example of the minimum acceptable level of information.*
- *A tabulated list of community partners the electrical corporation is working with or intends to work with to support its community outreach and education programs. Table 8-59 provides an example of the minimum acceptable level of information.*
- *A table of the various outreach and education awareness programs (i.e., campaigns, informal education, grant programs, participatory learning) that the electrical corporation implements before, during, and after wildfire, vegetation management, and PSPS events, including efforts to engage with partners in developing and exercising these programs. In addition, the electrical corporation must describe how it implements its overall program, including staff and volunteer needs, other resource needs, method for implementation (e.g., industry best practice, latest research in methods for risk communication, social marketing), long-term monitoring and*

- *evaluation of each program's success, need for improvement, etc. The narrative for this section is limited to two to three pages. The electrical corporation must also provide the information on its outreach and education awareness programs a in tabulated format.*

BVES's public outreach and education program was developed with the intent of increasing community resiliency to wildfire preparedness and mitigating the impact of potential PSPS events. BVES believes it is best practice to keep its customers informed on BVES regular operations and planned actions before, during, and after wildfire, vegetation management, and PSPS events.

Community outreach, public awareness, and communication efforts are key to reducing the impact on customers and the community from an event interrupting service or posing serious public risks. Effective planning and awareness limit the scope of extreme events. BVES works year-round to educate customers and coordinate with stakeholders to improve outreach, awareness, and communication. For example, BVES administers annual service territory wide customer surveys to gauge the community's awareness of wildfire risk and service territory offerings before, during, and after PSPS events. The results of the customer surveys are reported annually in the BVES Post-Season Report filed to the CPUC.

BVES communication plan consists of a two-pronged approach which involves proactive preparation prior to any emergency events occurring and notifications during and after such events. BVES's communication protocols vary slightly depending on the stakeholders involved, which may include customers, first responders, local mutual aid associates, and local government.

A primary focus of the BVES communication plan is customer outreach. This involves educating and preparing customers for various utility infrastructure related emergencies, including fire prevention, and proactive de-energization. To ensure customers have access to necessary information, BVES provides communication formats in various languages such as English, Spanish, Tagalog, Vietnamese, Chinese, French, Mixteco, and Zapoteco through online resources.

Overall, BVES communication plan seeks to engage stakeholders through open and transparent communication channels. This proactive approach empowers customers and other stakeholders to make informed decisions and take necessary actions in the event of an emergency.

**Table 8-58 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 |
| Populations with limited English proficiency | Limited access to prepare for, received, react, and recover from a wildfire or a PSPS event |
| Populations with impaired vision | Limited access to prepare for, received, react, and recover from a wildfire or a PSPS event |

| **Target Community Group** | **Interests or Concerns Before, During, and After Wildfire and PSPS Events** |
|---|---|
| Elderly | Impaired physical mobility which interferes with the ability to prepare for, react and recover from a wildfire or 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 8-59 List of Target Community Partners**

| **Community Partners** | **County** | **City** |
|---|---|---|
| Bear Valley Community Hospital | San Bernadino | Big Bear Lake |
| County/2-1-1 | San Bernadino | Bernadino |
| Senior Citizens of Big Bear Valley | San Bernadino | Big Bear Lake |
| Big Bear Chamber of Commerce | San Bernadino | Big Bear Lake |

- *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 8-60 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 and Radio Information | PSPS | Before | Public Safety Power Shutoff | PSPS customer information posted on website and advertised on radio | BVES Customers | Section 9 |
| Website and Radio Information | Wildfire | Before | General Wildfire Safety | General Wildfire Safety customer information posted on website and advertised on radio | BVES Customers | Section 9 |
| Website and Radio Information | Vegetation Management | Before | Vegetation Management | Vegetation Management customer information posted on website and advertised on radio | BVES Customers | Section 8.2 |
| Safety Website and Radio Information | Wildfire | Before | Electrical Safety | Electrical Safety customer information posed on website and advertised on radio | BVES Customers | Section 8.4 |

## 8.5.3 Engagement with Access and Functional Needs Populations

*In this section, the electrical corporation must provide an overview of its process for understanding, evaluating, designing, and implementing wildfire and PSPS risk mitigation strategies, policies, and procedures specific to AFN customers across its territory. The electrical corporation must also report, at a minimum, on the following:*

• *Summary of key AFN demographics, distribution, and percentage of total customer base.*

• *Evaluation of the specific challenges and needs during a wildfire or PSPS event of the electrical corporation's AFN customer base.*

*• Plans to address specific needs of the AFN customer base throughout the service territory specific to the unique threats that wildfires and PSPS events may pose for those populations before, during, and after the incidents.*

*This should include high-level strategies, policies, programs, and procedures for outreach, engagement in the development and implementation of the AFN-specific risk mitigation strategies, and ongoing feedback practices.*

As of March 31, 2023, the BVES identified 588 customer accounts with AFN, which equates to roughly 3% of the BVES customers. 188 of the AFN customer accounts were registered as medical baseline accounts. BVES uses an approach consistent with other IOUs to identify and track customers with AFN. BVES continues work on system modifications to CIS and OMS to allow the recording of AFN customer categories and data beyond medical baseline customers.

BVES is continuously evaluating and seeking to implement system enhancements and modifications 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. In 2022, BVES explored options to establish the ability to track AFN categories of customers beyond MBL in the CIS, including the following categorical identifiers: AFN customers enrolled in low-income programs, AFN customers with a physical, intellectual, or developmental disability, AFN customers with a chronic condition or injury, AFN customers identified with limited English proficiency, AFN customers in households with older adults / children, AFN homeless / transportation disadvantaged customers, and an additional AFN category for customers who wish to self-identify but may not necessarily fit into the aforementioned categories.

As a part of BVES's recent and ongoing system improvements, the capability to map AFN customers beyond MBL is anticipated to be integrated into the OMS soon and further refined throughout 2023.

In 2022, BVES partnered with MDC Research to execute two surveys to measure the public's awareness of messaging related to wildfire preparedness and safety. Customers were surveyed at random, targeted for either phone or web administration. Surveys were available to customers in English and Spanish. The first wave of surveys conducted June 13-29, 2022, resulted in completion of 400 surveys, including 13 from critical customers. The second wave of surveys conducted between December 28, 2022, and January 15, 2023 resulted in completion of 423 surveys, including 30 from critical customers. Notable customer survey findings include:

- Among those reporting that they rely on electricity for medical needs, one quarter are aware of additional notices from BVES.
- 98% of respondents indicated it would not be helpful to receive communications in a language other than English.
- 43% are aware they can update their contact information with BVES, and 61% of those have done so, in line with June 2022 findings.
- Similar to June 2022, 16% say they know whether their address is in PSPS area, and 11% are aware of a PSPS map on BVES's website.

In addition to customer surveys, MDC Research conducted Community Based Organization (CBO) interviews to request feedback and gather suggestions on the most effective approaches to PSPS communication within the community. The first wave of interviews resulted in two completed CBO interviews, whereas the second wave resulted in four completed CBO interviews. Notable CBO interview findings include:

- CBOs interviewed expressed a willingness and ability to share BVES PSPS preparedness information to the community during typical interactions, through social media and by handing out printed materials provided by BVES.
- English and Spanish are the primary languages required for effective communication in the communities BVES provides service.
- Simplified, easy-to-understand written communications are of importance to reach individuals with all levels of reading comprehension.

Additional survey information used to inform BVES's 2022 approach in effectively reaching customers include findings that email remains the most commonly recalled channel for wildfire preparedness communication. In terms of clarity, direct mail is rated the highest; bill inserts and other websites are rated as the most useful sources of information about wildfire preparedness. Customers say they most often recall seeing or hearing messages about wildfire on TV news, social networks, and through word of mouth.

In 2023, BVES will seek additional resources to execute surveys and research specific AFN needs before, during, and after PSPS events. BVES also plans to explore availability of resources and identification of gaps through further discussions and expansion of relationships with agencies, cities, counties, and local organizations.

BVES plans to continue improvements in accessibility of their webpage. Improvements in 2022 included the addition of 211 resource information on the web, as well as successful development of a self-identification tool for AFN customers in both Spanish and English.

BVES participated in the AFN Collaborative Planning Team, AFN Core Planning Team and provided executive representation on the Statewide Joint IOU AFN Advisory Council. To support individuals with AFN during potential PSPS events, BVES also participated in the creation of an annual support plan with assistance from regional and statewide AFN stakeholders. Beginning in 2023, that plan leverages the FEMA Comprehensive Preparedness Guide Six Step Process.

The main risk identified is "individuals with AFN are unable to use power for devices/equipment for health, safety, and independence due to an unexpected PSPS or are unprepared for a PSPS." BVES followed the same outline as the statewide AFN Collaborative Planning Team to address "Who," "What," and "How" to support individuals with AFN and mitigate risks associated with PSPS events. BVES uses the Electricity Dependent Definition: Individuals who are at an increased risk of harm to their health, safety, and independence during a Public Safety Power Shutoff for reasons including, but not limited to: Medical and Non-Medical; Behavioral, Mental and Emotional Health; Mobility and Movement; and Communication.

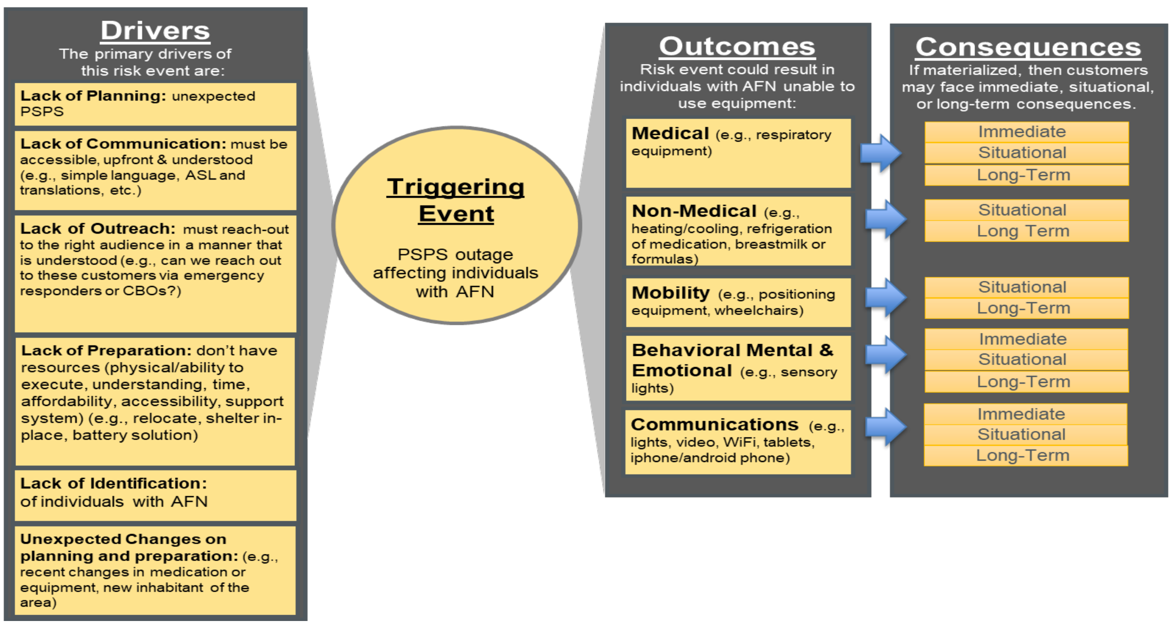
BVES AFN population consists of individuals who have developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking, older adults, children, people living in institutionalized settings, or those who are low-income, homeless, or transportation disadvantaged, including, but not limited to, those who are dependent on public transit or those who are pregnant.

**WHY:** As climate conditions change, wildfires have become a year-round threat. When wildfire conditions present a safety risk to our customers and communities, electric utilities may call for a PSPS as a measure of last resort. A PSPS, although necessary, disrupts the everyday lives of impacted individuals, including those with AFN. BVES seeks to mitigate the impact of PSPS on individuals with AFN.

**WHO:** The Joint IOU Statewide AFN Advisory Council and AFN Core Planning Team developed a definition of Electricity Dependent individuals that BVES seeks to support. That definition remains unchanged from 2022.

**WHAT & HOW:** Working alongside the AFN Collaborative Council and AFN Core Planning Team, the IOUs have worked to identify the goals, objectives, and potential opportunities for enhancements in 2023.

The overarching goal is to mitigate impacts of a PSPS on individuals with AFN served by the IOUs through improved customer outreach, education, assistance programs and services.




**BVES Figure 8-7: AFN Population Risks and Hazards During PSPS Event**

BVES developed the following communications outreach plan to notify AFN customers of pertinent PSPS status updates, including ongoing proactive education. BVES will continue to engage AFN customers throughout the year, and especially during wildfire season, to educate on the PSPS determination and notification process and how customers can prepare for prolonged de-energization through community meetings, social media, and BVES website.

San Bernadino 211 resource information is available on BVES website. BVES developed a self-identification tool for AFN customers in both Spanish and English languages, which is available on BVES website. BVES partnered with local public transportation service (MARTA), who will assist with non-medical transportation on an as available basis. BVES has contracted lodging services for customers during significant outage events on an as needed basis. BVES has staff available to deploy back up batteries on a small scale and educate each customer on the basic functionality of each battery unit. BVES also has an 8.4MW natural gas generation station in its service territory, available to produce energy during emergency events.

On February 1, 2023, BVES files with the CPUC "Bear Valley Electric Service, Inc. (U 913 E) Plan to Address Access and Functional Needs During De-Energization Events" which details BVES's plans to address AFN during PSPS events.

### 8.5.4 Collaboration on Local Wildfire Mitigation Planning

BVES understands the importance of collaborating with local government and agencies including county, city, and tribal agencies on wildfire mitigation. There are no tribal groups in the BVES service area. The key jurisdictions in the BVES service area are the City of Big Bear Lake, County of San Bernardino, Caltrans and the US Forest Service. BVES maintains strong working relationships with Additionally, City of Big Bear Lake, County of San Bernardino, Caltrans, US Forest Service, Big Bear Fire Department, San Bernardino Fire Department, CHP Arrowhead, San Bernardino County Sheriff's Department Big Bear Lake Patrol Station, Big Bear City Community Services Department and other local groups.

BVES attends the Big Bear Valley Mountain Mutual Aid Association (MMAA) meetings, held five times per year, and at each meeting discusses wildfire mitigation planning efforts. MMAA membership includes: City of Big Bear Lake, Big Bear Fire Department, San Bernardino County Fire, San Bernardino County Department of Public Health, San Bernardino County Office of Emergency Services (OES), San Bernardino County Sheriff's Department, San Bernardino County Transportation Authority, San Bernardino County Emergency Communications Service (ECS), US Forest Service, California Highway Patrol, California Department of Transportation, Big Bear Airport, Big Bear City Community Services District, Big Bear Lake Department of Water & Power, Big Bear Lake Municipal Water District, Big Bear Area Regional Water Authority, Southwest Gas, Bear Valley Community Healthcare District, Bear Valley Unified School District, Mountain Area Regional Transit Authority, Bear Mountain Ski Resorts, Big Bear Chamber of Commerce, Big Bear Lake Resort Association, Big Bear Valley Recreation & Park District, American Red Cross, Big Bear Community Emergency Response Team (CERT), Big Bear Valley Community Organizations Active in Disaster (COAD), Big Bear Valley Voluntary Organizations Active in Disaster (VOAD), Civil Air Patrol, and Salvation Army.

Periodic meetings and recurring communication between BVES and local government and agencies strengthen the likelihood of demonstrating resiliency during emergencies. Due to the small service area, BVES can effectively engage local government and agencies frequently and prioritizes these engagements due to the significant impact that they have in achieving community buy-in. BVES participates in **community-based** fuels management and defensible space programs with the USFS. BVES supports, the broader Big Bear Valley fuels management and defensible space community programs by establishing collaborative activities within the service area. Since the initial 2005 Big Bear Valley Community Wildfire Protection Plan (CWPP), significant progress has been made through ongoing and well-coordinated efforts between various local, state, and federal agencies to reduce hazardous fuels across the valley through a wide range of fuel reduction projects.

See Table 8-70 for BVES local collaboration in resource conservation programs, structural hardening programs, and community wildfire protection plans.

**Table 8-61 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<br>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<br>Provided verbal comments and input |
| City of Big Bear Lake | Wildfire Mitigation Plan | November 2, 2022 | Meeting with City Manager and City Engineer |
| Big Bear Valley Mountain Mutual Aid Association | Wildfire Mitigation Initiatives and 2022 Weather Forecast | April 12, 2022 | Meeting with representatives from City of Big Bear Lake, San Bernardino County, Big Bear Fire Department, Sheriff Big Bear Lake, CALTRANS, and CHP.<br>Presentation by NOAA Meteorologist. |

- *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 8-62 Key Gaps and Limitations in Collaborating on Local Wildfire Mitigation Planning**

| Subject of Gap or Limitation | Brief Description of Gap or Limitation | Strategy for Improvement |
|---|---|---|
| Community engagement feedback | Gap: Limited feedback mechanisms are in place to gain insight on the effectiveness of community engagement activities. | BVES will work on implementing immediate feedback mechanisms to its community engagement activities. |

### 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.*

BVES shares best practices and collaborates with other California IOUs in working group meetings and public communications. Additionally, BVES collaborates with other out of state electric utilities. The California IOUs share feedback provided by customers and the public regarding recommendations and concerns. BVES engages with utilities outside of California to exchange best practices both for utility wildfire mitigation and stakeholder cooperation when responding to wildfires. BVES expanded its efforts in this initiative area during 2022 and, accordingly, increased the projected operational expenditure spending for this initiative going forward.

BVES attended the 2023 DistribuTECH International transmission and distribution (T&D) conference where lessons learned and information on wildfire mitigation, manufactures and vendors of T&D equipment were shared and discussed. BVES sent several planning and field staff to this conference in February. Additionally, BVES sent attendees to the 2023 Power Delivery Design Conference in February 2023 where wildfire mitigation best practices were a main topic and information was exchanged with out-of-state utilities and utility industry experts. In March 2023, BVES participated at the 2023 Wildfire Mitigation for Utilities Conference organized by Electric Utility Consultants, Inc. (EUCI). At this conference, wildfire mitigation was discussed with California utilities and agencies, out of state utilities and agencies, and utility industry equipment suppliers and service providers. BVES intends to be more involved in conferences, workshops, and working groups throughout 2023.

In 2022, BVES attended the Institute of Electrical and Electronics Engineers (IEEE) Transmission and Distribution Conference and the DistribuTECH International transmission and distribution (T&D) conference.

BVES currently does not have a wire down detection program, nor does it have a timeline to procure one. As solutions are developed in this space, BVES will look to collaborate with other utilities on the effectiveness of their programs.

**Table 8-63 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-Ongoing | Technical | BVES<br>Liberty<br>PC<br>PG&E<br>SCE<br>SDG&E | 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<br>• 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.<br>• Conductors. This is due to the reduced vulnerability to arcing/faults afforded by the multi-layered polymeric insulating sheath material.<br>• 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).<br>• Laboratory studies and field experience have shown that CCs largely mitigated arcing due to external contact.<br>• 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). |
| Risk Model Working Group | 2022-Ongoing | Technical | BVES<br>Liberty<br>PC<br>PG&E<br>SCE<br>SDG&E | Risk modeling methodology sharing among participating utilities | Ongoing<br>“annual” working group meetings<br>Next Step<br>Establish uniform approach to risk modeling for utilities |

| Best Practice Subject | Dates of Collaboration (YYYY-YYYY) | Technical or Programmatic | Utility Partner(s) | Description of Best Practice Sharing or Collaborating | Outcome |
|---|---|---|---|---|---|
| Workshop on Vegetation Management Best Practices | 2022-Ongoing | BVES<br>Liberty<br>PC<br>PG&E<br>SCE<br>SDG&E | BVES<br>Liberty<br>PC<br>PG&E<br>SCE<br>SDG&E | Share best practices in vegetation management among participating utilities and experts in the vegetation management field | Improved vegetation management programs |
| Wildfire Mitigation | 2022-Ongoing | Technical and Programmatic | Varies depending on engagement | BVES engages and shares best practices with other utilities (in state and out of state), state agencies, industry trade associations, vendors, and other experts in wildfire mitigation by attending conferences and other external events | Participating in industry conferences and other forums as well as engaging with peer utilities provide regular opportunities to share best practices on topics pertaining to wildfire mitigation, including PSPS. |

# 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 Key PSPS Statistics

*In this section, the electrical corporation must include a summary table of PSPS event data. These data must be calculated from the same source used in the 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 | 0 | 0 | 0 |
| Jan 1 – Dec 31, 2021 | 0 | 0 | 0 | 0 |
| Jan 1 – Dec 31, 2022 | 0 | 0 | 0 | 0 |

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.

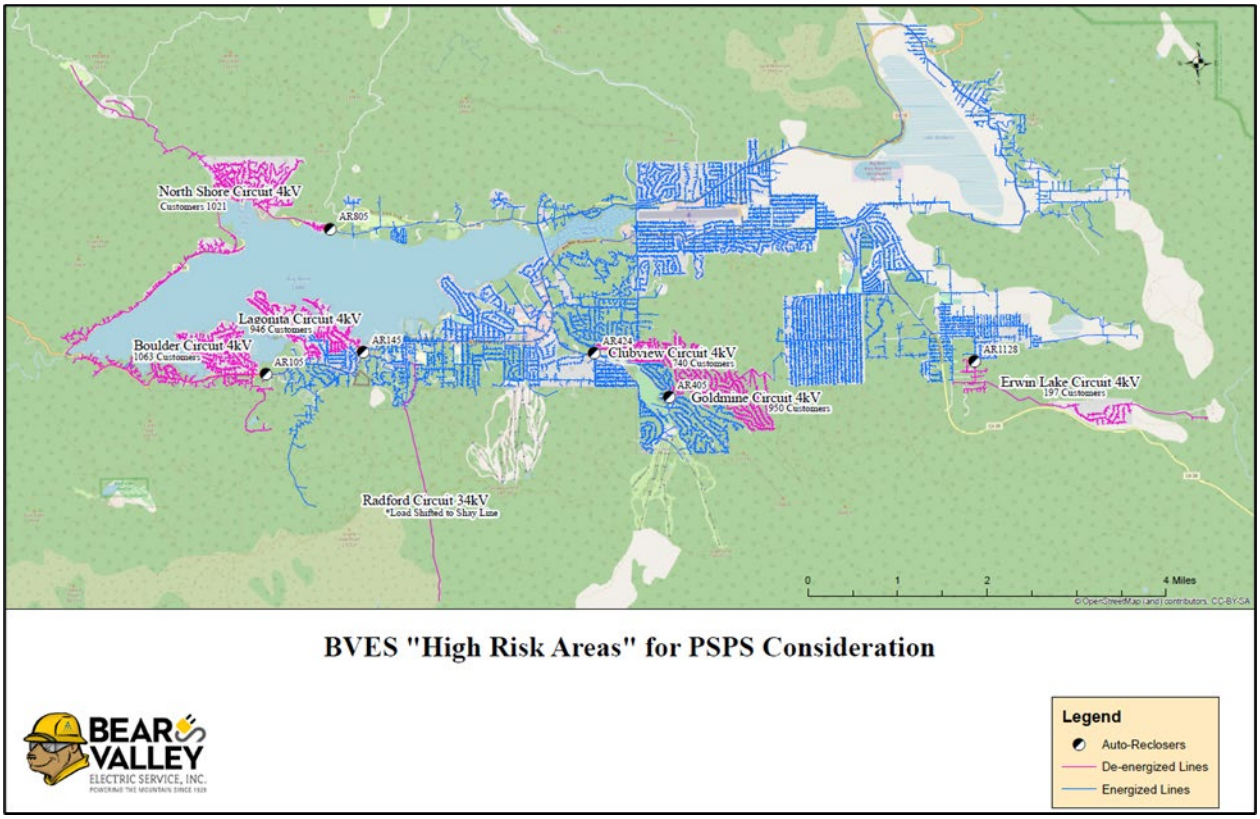



**Figure 9-1 BVES High Risk Areas for PSPS Consideration**

## 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)**

| 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 |

| 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 #) |
|---|---|---|---|---|---|
| Conduct annual table-top and functional exercises 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 | Table-top exercise results and Pre- and Post-Season Report | Q2 Annually | Section 8.4.2 |

| **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 #)** |
|---|---|---|---|---|---|
| Conduct service restoration training with supervisory and field personnel each year prior to the fire season. | Emergency preparedness plan EP-1<br>External collaboration and coordination EP-2<br>Public emergency communication strategy<br>Preparedness and planning for service restoration EP-4<br>Customer support in wildfire and PSPS emergencies EP-5 | CPUC's PSPS guidelines and rules | Training Log | Q2 Annually | 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<br>Outreach Records | Q2 Annually | Section 8.4.4 |

| 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 #) |
|---|---|---|---|---|---|
| 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 | Ongoing | 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 9-4 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 | Ongoing | 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 | Emergency preparedness plan EP-1 | CPUC's PSPS guidelines and rules | N/A | Ongoing | Section 8.4.2 |

| 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 #) |
|---|---|---|---|---|---|
| high-risk area is shrunk due to grid hardening efforts, new sectionalizing devices may be 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<br>Internal records of outreach | Ongoing | 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 9-5 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 |
|---|---|---|---|---|---|---|---|---|
| Covered Conductor Installation – Circuit miles (34kV & 4kV) | GD_1 | 12.9 | 17.4% | 12.9 | 17.4% | 12.9 | 17.4% | Completed Work Orders |
| Covered Conductor Installation – Circuit miles (Radford Line) | GD_2 | 2.7 | 62.5% | 0 | N/A | 0 | N/A | Completed Work Orders |
| Number of Customers Impacted | EP_1 | 160[4] | N/A | 160 | N/A | 133 | N/A | QDR |

[4] The number of customers impacted is calculated by estimating the average number of customers impacted per year based upon the number of PSPS events that is expected annually *i.e.*, every approximately 1 out of 25 years for 2023 and 2024, and 1 out of 30 years in 2025.

| 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 |
|---|---|---|---|---|---|---|---|---|
| Number of Circuits De-energized | EP_1 | 0.08[5] | N/A | 0.08 | N/A | 0.07 | N/A | QDR |
| Number of PSPS events | EP_5 | 0.04 | N/A | 0.04 | N/A | 0.03 | N/A | QDR |

To date BVES has not experienced conditions to invoke a PSPS and, thus, has never executed a PSPS event. Additionally, analysis of historical weather since 2015 indicates conditions to warrant invoking a PSPS have not occurred in the BVES service area during that time period. However, there is always some small, and likely increasing likelihood that abnormal fire threat weather (*i*.e., exceptionally dry and windy conditions) may require BVES to invoke to a PSPS. The winter of 2023 is a good example of anomalous conditions; during that winter BVES experienced the most snow on record by over 20 inches. Similarly, at some point BVES could experience dry conditions and high winds well beyond normal that would trigger PSPS conditions. Climate change and frequent and persistent droughts increase the likelihood of environmental conditions that could lead to reaching a PSPS threshold. Conversely, as BVES continues to harden its grid, the threshold for invoking a PSPS increases and, therefore, the likelihood further decreases. Therefore, there will always be some PSPS risk within the BVES service territory for the foreseeable future.

BVES remains committed to continue developing the capability to better calculate PSPS risk using probabilistic models. As of now, BVES currently estimates the PSPS risk to be a 1 in 25 year event that would affect at most 2 circuits and 4,000 customers given the grid conditions in 2023 and 2024 (projected). Given further grid hardening efforts, BVES evaluated that the PSPS risk in 2025 to be a 1 in 30 year event that would affect at most 2 circuits and 4,000 customers. Thus, the target values in Table 9-5 for “Number of Customers Impacted”, “Number of Circuits De-energized”, and “Number of PSPS events” are calculated for 2023 and 2024 based on PSPS being a 1 in 25 year event and for 2025 based on PSPS being a 1 in 30 year event.

The initiatives in the Table 9-5 are designed to mitigate that risk and ensure readiness in the case of conditions requiring PSPS activation. 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:*

[5] The number of circuits de-energized is calculated by estimating the average number of circuits impacted per year based upon the number of PSPS events that is expected annually *i.e.,* every approximately 1 out of 25 years for 2023 and 2024, and 1 out of 30 years in 2025.

- *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 table-top 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.

**BVES Table 9-1 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 |

**BVES Table 9-2 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 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 TripSavers 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 9-6 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.

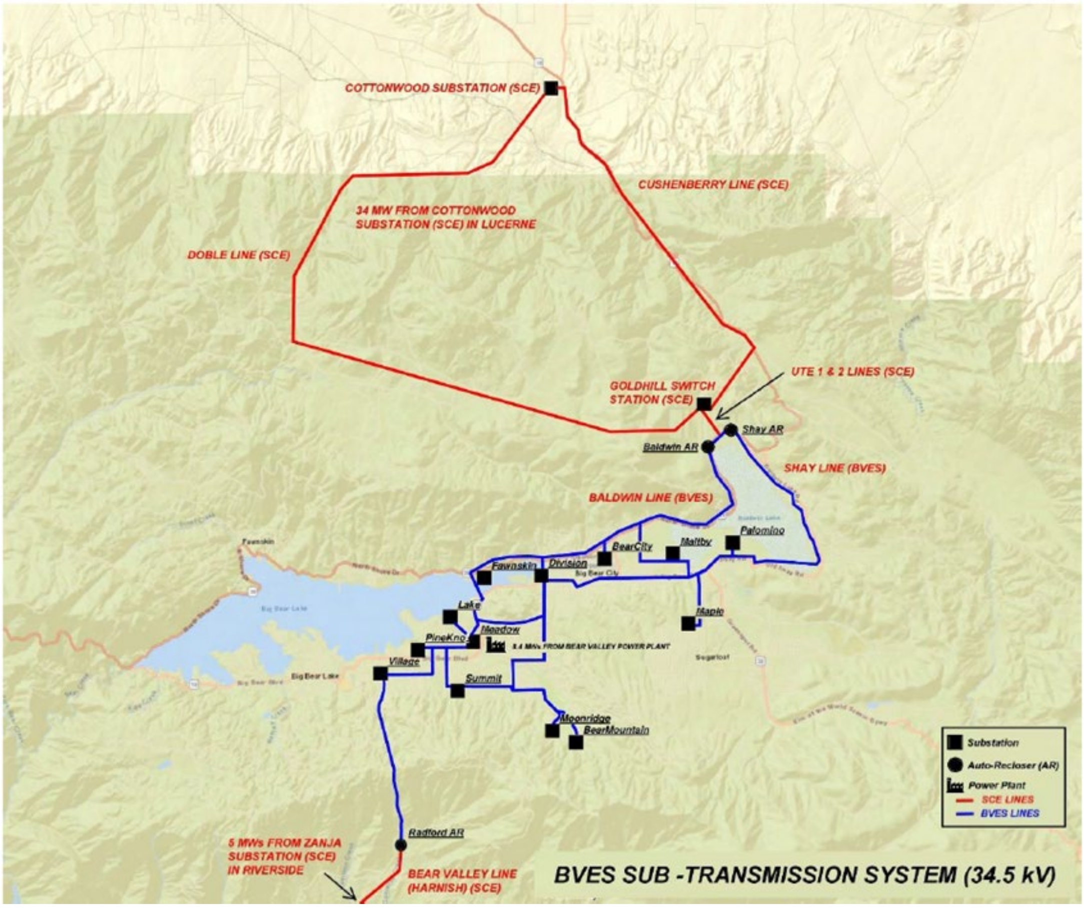



**Figure 9-2 BVES Supply Lines, Sources of Power and Sub-Transmission System**

The table below outlines BVES's action plan for addressing partial or complete loss of power due to SCE supply line de-energization events.

**BVES Table 9-3 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.<br>Energize Radford Line as needed to meet load demand. If the Utility Manager deems it necessary, energize the Radford Line as needed for reliability.<br>Startup BVPP as needed to meet load demand.<br>No reduction on load necessary, since the Doble and Cushenberry are capable of carrying the other's load.<br>Implement applicable portions of BVES Emergency Response Plan for a partial loss of SCE supply lines |

| Condition | BVES Action |
|---|---|
| SCE De-energizes Bear Valley Line for PSPS. | Notify key internal staff and brief Field Operations on conditions for situational awareness.<br>If Radford is energized, shift loads to Shay Line prior to de-energizing for PSPS. Generally, this should be done about 4 hours prior to the SCE de-energizing the line.<br>If needed, start up BVPP to meet load demand.<br>If needed, instruct interruptible customers (Bear Mountain Resorts) to reduce load as needed to meet load demand.<br>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.<br>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.<br>Prepare for potentially losing all SCE supply lines into BVES service area.<br>Prepare for sustained BVPP operations and rolling blackouts.<br>Evaluate distribution circuit loads.<br>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.<br>If not already done, energize the Radford Line.<br>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:<br>Open the Shay and Baldwin automatic reclosers.<br>"Express" the Radford Line to Meadow Substation without overloading the Radford Line per Field Operations' switching order.<br>Startup BVPP, place enginators online and increase load to within the combined capacity of the BVPP and Radford Line.<br>Implement BVES Emergency Response Plan for sustained loss of SCE supplies from Lucerne including "rolling blackout" procedures.<br>Prepare for sustained BVPP operations and rolling blackouts.<br>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.<br>If the Radford Line is energized, shift loads to the Shay Line.<br>Four hours prior to SCE de-energizing the lines, per the Field Operations Supervisor's direction, perform the following:<br>Start up all BVPP enginators.<br>Reduce system load to within the capacity of BVPP by isolating distribution circuits as directed by the Field Operations Supervisor.<br>Once system load is matched with BVPP capacity, open the Shay and Baldwin automatic reclosers.<br>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.

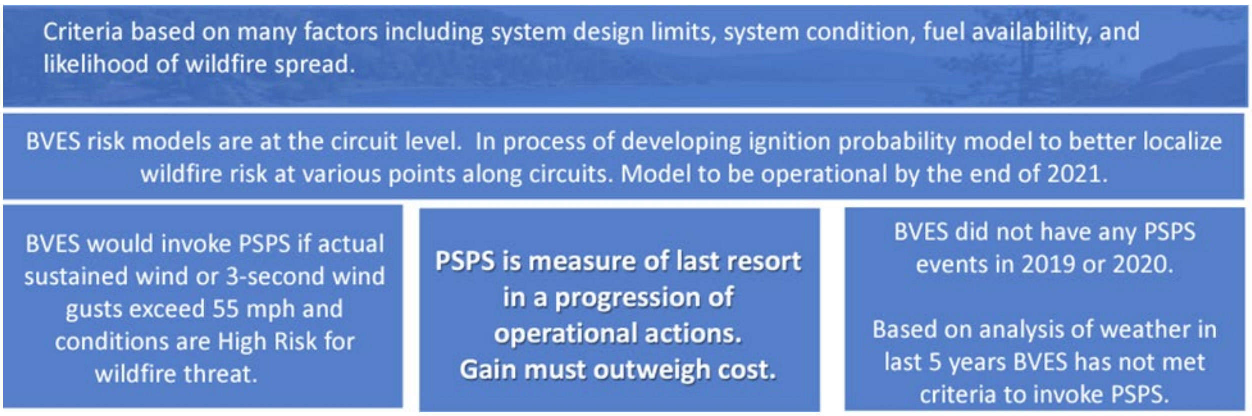



**Figure 9-3 PSPS Decision-Making Criteria**

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'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.

**BVES Table 9-4 PSPS Re-Energization and Post-Event Strategy**

| PSPS Activity | Phase Event | Internal Action | External Coordination |
|---|---|---|---|
| Restoration | **Re-energization**<br><br>(Extreme fire conditions subside to safe levels as validated by field conditions) | **Operations & Planning:**<br>Field Crews validate that the extreme fire weather conditions have subsided to safe levels as designated by the Field Operations Supervisor and report these conditions to Dispatch.<br>Field Crews conduct field inspections and patrols of facilities that were de-energized.<br>When field inspections and patrols are completed satisfactorily, power is restored to the affected circuits. | **Local Government, Agencies, and Partner Organizations:**<br>Send "Intent to Restore" notice to local government, agencies, and partner organizations. Encourage widest dissemination of this information.<br>Coordinate with the emergency management community, first responders, and local government in managing restorations.<br>Send "Restoration Complete" notice to local government, agencies, and partner organizations once power is fully restored or an update if restoration is delayed.<br>Update Stakeholders Portal |

| PSPS Activity | Phase Event | Internal Action | External Coordination |
|---|---|---|---|
| | | As SCE restores supply lines, Field Crews conduct switching operations as directed by Field Operations Supervisor to restore systems normal.<br><br>**Customer Service:**<br><br>Finalize "Intent to Restore" notice to include ETR(s) and obtain President's approval to release.<br>Finalize "Restoration Complete" notice to be issued when power is fully restored and obtain President's approval to release.<br>Breakdown of CRC including removal/storage of all equipment and supplies<br>Prepare post-event reports<br>Update Stakeholders Portal | **Customer Outreach:**<br><br>Post "Intent to Restore" notice on BVES website and social media.<br>Issue "Intent to Restore" press release for local media.<br>Send out "Intent to Restore" notice via IVR.<br>Send out "Intent to Restore" notice via Text<br>Send out "Intent to Restore" notice via email<br>Post "Restoration Complete" notice on BVES website and social media once power is fully restored or an update if restoration is delayed.<br>Issue "Restoration Complete" press release for local media once power is fully restored or an update if restoration is delayed.<br>Send out "Restoration Complete" notice via IVR once power is fully restored or an update if restoration is delayed.<br>Send out "Restoration Complete" notice via Text once power is fully restored or an update if restoration is delayed.<br>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:**<br><br>Utility Manager conduct lessons learned with applicable staff. Include Customer Service and solicit input from Local | **CPUC Safety Enforcement Division:**<br><br>File a report (written) to President of SED no later than 10 business days after |

| PSPS Activity | Phase Event | Internal Action | External Coordination |
|---|---|---|---|
| | | Government, Agencies, and Partner Organizations.<br><br>If applicable, update plan and procedures per the lessons learned.<br><br>Prepare PSPS Post-Event Report required by ESRB-8 and forward to President and Manager Regulatory Affairs for approval. | 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. | Completed 2021 | Section 6; pg. 42<br>Section 7.1; pg. 85-86 |
| 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. | Completed 2021 | Section 8.3.1.1 – 8.3.1.3; pg. 233-238 |
| 03 | 2020 / 2021 | | Grid Design and System Hardening | Replicated initiatives among California IOUs on | BVES has worked to better account for its mitigation measures | Completed 2021 | Section 8.1; pg. 109-186 |

| ID # | Year of Lesson Learned | Subject | Type or Source of Lesson Learned | Description of Lesson Learned | Proposed WMP Improvement | Timeline for Implementation | Reference |
|---|---|---|---|---|---|---|---|
| | | | | 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 | Ongoing | Section 8.1.1.1 – 8.1.1.3; pg. 110-126 |

| ID # | Year of Lesson Learned | Subject | Type or Source of Lesson Learned | Description of Lesson Learned | Proposed WMP Improvement | Timeline for Implementation | Reference |
|---|---|---|---|---|---|---|---|
| | | | | | 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. | Ongoing | Section 6; pg. 43-84 |
| 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 | Completed 2021 | Section 6; pg. 43-84 |

| ID # | Year of Lesson Learned | Subject | Type or Source of Lesson Learned | Description of Lesson Learned | Proposed WMP Improvement | Timeline for Implementation | Reference |
|---|---|---|---|---|---|---|---|
| | | | | | 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 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. | On-going | Section 6; pg. 43-84 |

| ID # | Year of Lesson Learned | Subject | Type or Source of Lesson Learned | Description of Lesson Learned | Proposed WMP Improvement | Timeline for Implementation | Reference |
|---|---|---|---|---|---|---|---|
| 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 or replacement, for which BVES has met its internal targets. | On-going | Section 6; pg. 43-84 |
| 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 | Completed 2021 | Section 6; pg. 43-84 |

| ID # | Year of Lesson Learned | Subject | Type or Source of Lesson Learned | Description of Lesson Learned | Proposed WMP Improvement | Timeline for Implementation | Reference |
|---|---|---|---|---|---|---|---|
| | | | | | 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 | Completed 2021 | Section 6; pg. 43-84 |

| ID # | Year of Lesson Learned | Subject | Type or Source of Lesson Learned | Description of Lesson Learned | Proposed WMP Improvement | Timeline for Implementation | Reference |
|---|---|---|---|---|---|---|---|
| | | | | | 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. | Ongoing | Section 8.5.4 – 8.5.5; pg. 361-366 |
| 12 | 2022 | | Tracking of Risk Events | The need for BVES to follow the Emergency Response Disaster Plan (EDRP) precisely | No direct link to WMP | N/A | N/A |
| 13 | 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 | Completed 2022 | Section 8.4.2; pg. 266-284<br>8.4.3; pg. 294-327<br>9.1.2; pg. 368-369<br>9.1.4; pg. 375 |

| ID # | Year of Lesson Learned | Subject | Type or Source of Lesson Learned | Description of Lesson Learned | Proposed WMP Improvement | Timeline for Implementation | Reference |
|---|---|---|---|---|---|---|---|
| | | | | | 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. | | |
| 14 | 2022 | | Continued Improvement per Energy Safety Guidance | More detail and more identifiers in its customer database would benefit BVES<br><br>Energy Safety Advised BVES to make updates in its Spatial Data to include more information for clarity and granularity | Both these items apply to Customer Outreach and Emergency Response. No direct connection to WMP but guided changes to internal BVES plans.<br><br>Per Energy Safety request, BVES added flags in November 2022 to the Customer Data Base regarding customers with security or access concerns. This allows BVES to know ahead | Completed 2022 | QDR |

| ID # | Year of Lesson Learned | Subject | Type or Source of Lesson Learned | Description of Lesson Learned | Proposed WMP Improvement | Timeline for Implementation | Reference |
|---|---|---|---|---|---|---|---|
| | | | | | of time if there are concerns when entering a customer sight.<br><br>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). | | |
| 15 | 2022 | | Covered Conductor Working Group | The utilities agree that it is helpful to share information, practices, and data across the utilities as this can lead to improvements in reducing wildfire | General review of communication plans/targets for the 2023 cycle | Ongoing | Section 8.5.5; pg. 363-366 |

| ID # | Year of Lesson Learned | Subject | Type or Source of Lesson Learned | Description of Lesson Learned | Proposed WMP Improvement | Timeline for Implementation | Reference |
|---|---|---|---|---|---|---|---|
| | | | | 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. | | | |
| 16 | 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. | Ongoing | Section 8.5.5; pg. 363-366 |

# 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 BVES Table 11-1 below.

**BVES 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:<br>- BVES plans to schedule patrol, detailed, and other inspections based on modeling and risk assessments.<br>- 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.<br>- BVES plans to base procedures and checklists on predictive modeling and to increase the granularity from a service territory to a circuit level.<br>- 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 |

| Issue # | Title | Status | Comments |
|---|---|---|---|
| RN-BVES-22-03 | BVES has not sufficiently connected its risk assessment with its mitigation initiative prioritization | Continuing to monitor the below efforts:<br>a) Integrate its response to BVES-21-07, found in Appendix A, into WMP Section 7.3.3 “Grid Design and System Hardening.”<br>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.<br>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).<br>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:<br>a) Provide details on progress made developing and implementing its formal QA/QC process, including implementation timing.<br>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. |

| Issue # | Title | Status | Comments |
|---|---|---|---|
| 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:<br>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.<br>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:<br>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.<br>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 BVES Table 11-2.

**BVES 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 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 |