Liberty Utilities (CalPeco Electric) LLC (U 933-E)

2022 Wildfire Mitigation Plan Update

Public Version

May 6, 2022

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0. GLOSSARY OF DEFINED TERMS

Term	Definition
10-hour dead fuel moisture content	Moisture content of small dead vegetation (*e.g.*, grass, leaves, etc. that burn quickly but not intensely) that can respond to changes in atmospheric moisture content within 10 hours.
Access and functional needs populations	Per Cal. Gov't Code § 8593.3 and D.19-05-042, 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.
Authority Having Jurisdiction (AHJ)	AHJ, party with assigned responsibility, depending on location and circumstance.
Asset (utility)	Electric lines, equipment, or supporting hardware.
At-risk species	Species of vegetation that have an elevated risk of (1) coming into contact with powerlines, (2) causing an outage or ignition, and/or (3) easily ignitable and within close enough proximity to potential arcing, sparks and/or other utility equipment thermal failures. "At-risk species" must be a function of species-specific characteristics including growth rate, failure rate of limbs, trunk, and/or roots (as compared to other species), height at maturity, flammability, vulnerability to disease or insects, etc.
Baseline (ignition probability, maturity)	A measure, typically of the current state, which establishes a starting point for comparison with measures from other states.
Carbon dioxide equivalent	Tons of greenhouse gases (GHG) emitted, multiplied by the global warming potential relative to carbon dioxide.
Circuit mile	The total length in miles of separate circuits regardless of the number of conductors used per circuit.
Contractor	Any individual in the temporary and/or indirect employ of the utility whose limited hours and/or time-bound term of employment are not considered as "full-time" for tax and/or any other purposes.

Critical facilities and infrastructure	For brevity in the WMP, "critical facilitates and infrastructure" may be shortened to "critical infrastructure" and/or "critical facilities" throughout the WMP. Critical facilities and infrastructure is defined in accordance with the definition adopted in D.19-05-042 and modified in D.20-05-051: those facilities and infrastructure that are essential to the public safety and that require additional assistance and advance planning to ensure resiliency during de energization events. Namely:
	• Emergency Services Sector
	    o Police Stations
	    o Fire Stations
	    o Emergency Operations Centers
	    o Public Safety Answering Points
	• Government Facilities Sector
	    o Schools
	    o Jails and prisons
	• Healthcare and Public Health Sector
	    o Public Health Departments

	o Medical facilities, including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers and hospice facilities (excluding doctor offices and other non-essential medical facilities) • Energy Sector o Public and private utility facilities vital to maintaining or restoring normal service, including, but not limited to, interconnected publicly owned utilities and electric cooperatives • Water and Wastewater Systems Sector o Facilities associated with the provision of drinking water or processing of wastewater including facilities used to pump, divert, transport, store, treat and deliver water or wastewater • Communications Sector o Communication carrier infrastructure including selective routers, central offices, head ends, cellular switches, remote terminals and cellular sites • Chemical Sector o Facilities associated with the provision of manufacturing, maintaining, or distributing hazardous materials and chemicals (including Category N-Customers as defined in D.01-06-085) • Transportation Sector o Facilities associated with automobile, rail, aviation, major public transportation, and maritime transportation for civilian and military purposes
Customer hours	Total number of customers, multiplied by the average number of hours (*e.g.*, of power outage).
Data cleaning	Calibrating raw data to remove errors (including typographical and numerical mistakes).
Dead fuel moisture content	Moisture content of dead vegetation, which responds solely to current environmental conditions and is critical in determining fire potential.
Detailed inspection	In accordance with GO 165, an inspection where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.
Enhanced inspection	Inspection whose frequency and thoroughness exceeds the requirements of the detailed inspection, particularly if driven by risk calculations.
Enterprise System	A centralized information system that ensures data may be shared throughout all functional levels and management hierarchies of an organization, as needed.
Evacuation impact	Number of people evacuated, with the duration for which they are evacuated, from homes and businesses, due to wildfires.
Evacuation zone	Areas designated by CAL FIRE and local fire agency evacuation orders, to include both “voluntary” and “mandatory” in addition to other orders such as “precautionary” and “immediate threat”.
Fire Season	The time of year that wildfires are most likely to take place for a given geographic region due to historical weather conditions, vegetative characteristics and impacts of climate change. Goals and targets which have milestones related to the onset, duration, or end of “fire season” or “height of fire season” must be accompanied with calendar dates.

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Frequently de-energized circuit	A circuit which has been de-energized pursuant to a de-energization event to mitigate the risk of wildfire three or more times in a calendar year.
Fuel density	Mass of fuel (vegetation) per area which could combust in a wildfire.
Fuel management	Removing, thinning, or otherwise altering vegetation to reduce the potential rate of propagation or intensity of wildfires.
Fuel moisture content	Amount of moisture in a given mass of fuel (vegetation), measured as a percentage of its dry weight.
Full-time employee	Any individual in the ongoing and/or direct employ of the utility whose hours and/or term of employment are considered as "full-time" for tax and/or any other purposes.
G.O. 95 nonconformance	Condition of a utility asset that does not meet standards established by General Order 95.
Greenhouse gas (GHG) emissions	Health and Safety Code 38505 identifies seven greenhouse gases that ARB is responsible to monitor and regulate in order to reduce emissions: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and nitrogen trifluoride (NF3).
Grid hardening	Actions (such as equipment upgrades, maintenance, and planning for more resilient infrastructure) taken in response to the risk of undesirable events (such as outages) or undesirable conditions of the electrical system in order to reduce or mitigate those events and conditions, informed by an assessment of the relevant risk drivers or factors.
Grid topology	General design of an electric grid, whether looped or radial, with consequences for reliability and ability to support de-energization (*e.g.*, being able to deliver electricity from an additional source).
High Fire Threat District (HFTD)	Per D.17-01-009, areas of the State designated by the Office of Energy Infrastructure Safety and CAL FIRE to have elevated wildfire risk, indicating where each utility must take additional action (per GO 95, GO 165, and GO 166) to mitigate wildfire risk.
Highly rural region	In accordance with 38 CFR 17.701, "highly rural" must be defined as those areas with a population of less than 7 persons per square mile. For the purposes of the WMP, "area" must be defined as census tracts.
High Wind Warning (HWW)	Level of wind risk from weather conditions, as declared by the National Weather Service. For historical NWS data, refer to the Iowa State University Iowa archive of NWS watch / warnings.[1]
HWW overhead (OH) Circuit Mile Day	Sum of overhead circuit miles of utility grid subject to High Wind Warnings (HWW, as defined by the National Weather Service) each day within a given time period, calculated as the number of overhead circuit miles that are under an HWW multiplied by the number of days those miles are under said HWW. For example, if 100 overhead circuit miles are under an HWW for 1 day, and 10 of those miles are under HWW for an additional day, then the total HWW OH circuit mile days would be 110.
Ignition probability	The relative possibility that an ignition will occur, probability is quantified as a number between 0% and 100% (where 0% indicates impossibility and 100% indicates certainty). The higher the probability of an event, the more certainty there is that the event will occur. (Often informally referred to as likelihood or chance).
Ignition-related deficiency	Any condition which may result in ignition or has previously resulted in ignition, even if not during the past five years.

[1] https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml

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Impact/consequence of ignitions	The effect or outcome of a wildfire ignition upon objectives, which may be expressed by terms including, although not limited to, maintaining health and safety, ensuring reliability, and minimizing economic and/or environmental damage.
Initiative	Measure or activity proposed or in process designed to reduce the consequences and/or probability of wildfire or PSPS.
Inspection protocol	Documented procedures to be followed in order to validate that a piece of equipment is in good condition and expected to operate safely and effectively.
Invasive species	A species that is: 1) non-native (or alien) to the ecosystem under consideration and 2) whose introduction causes or is likely to cause economic or environmental harm or harm to human health.
Level 1 finding	In accordance with GO 95, an immediate safety and/or reliability risk with high probability for significant impact.
Level 2 finding	In accordance with GO 95, a variable (non-immediate high to low) safety and/or reliability risk.
Level 3 finding	In accordance with GO 95, an acceptable safety and/or reliability risk.
Life expectancy	Anticipated years that a piece of equipment can be expected to meet safety and performance requirements.
Limited English Proficiency (LEP)	Populations with limited English working proficiency based on the International Language Roundtable scale.
Line miles	The number of miles of transmission and/or distribution line. Differs from circuit miles because individual circuits, such as the two circuits of a double-circuit line, are not counted separately in circuit miles but are counted as separate total miles of line.
Live fuel moisture content	Moisture content within living vegetation, which can retain water longer than dead fuel.
Lost energy	Energy that would have been delivered were it not for an outage.
Major roads	Interstate highways, U.S. highways, state and county routes.
Match drop simulation	Wildfire simulation method that takes an arbitrary ignition and forecasts propagation and consequence/impact.
Member of the public	Any individual not employed by the utility.
Multi-attribute value function	Risk calculation methodology introduced during CPUC's S-MAP and RAMP proceedings.
Near miss	Previously used to define an event with probability of ignition. Redefined under "Risk event."
Need for PSPS	When utility's criteria for utilizing PSPS are met.
Noncompliant clearance	Rights-of-way whose vegetation is not trimmed in accordance with the requirements of GO 95.
Outages of the type that could ignite a wildfire	Outages that, in the judgment of the utility, could have ignited a wildfire.
Outcome metrics	Measurements of the performance of the utility and its service territory in terms of both leading and lagging indicators of wildfire, PSPS, and other consequences of wildfire risk, including the potential unintended consequences of wildfire mitigation work, such as acreage burned by utility-related ignitions.
Overcapacity	When the energy transmitted by utility equipment exceeds that of its nameplate capacity.

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Patrol inspection	In accordance with GO 165, a simple visual inspection of applicable utility equipment and structures that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.
Percentile conditions	Top X% of a particular set (*e.g.*, wind speed), based on a historical data set with sufficient detail. For example, "Top 95 percentile wind speeds in the last 5 years" would refer to the 5% of avg daily wind speeds recorded by each weather station. If 1,000 weather stations recorded average daily wind speeds over 10 days, then the 95th percentile wind speed would be the top 5% of weather station-days. In this example, there will be 10 days each with 1,000 weather station reports and a total of 10,000 weather station-days, so 50 observations will be in the top 5%. The lowest wind speed in this top 5% would be the "95th percentile wind speed".
Planned outage	Electric outage announced ahead of time by the utility.
Preventive maintenance (PM)	The practice of maintaining equipment on a regular schedule, based on risk, elapsed time, run-time meter readings, or number of operations. The intent of PM is to "prevent" maintenance problems or failures before they take place by following routine and comprehensive maintenance procedures. The goal is to achieve fewer, shorter, and more predictable outages.
Priority essential services	Critical first responders, public safety partners, critical facilities and infrastructure, operators of telecommunications infrastructure, and water utilities/agencies.
Program targets	Quantifiable measurements of activity identified in WMPs and subsequent updates used to show progress towards reaching the objectives.
Progress metrics	Measurements that track how much utility wildfire mitigation activity has changed the conditions of utility wildfire risk exposure or utility ability to manage wildfire risk exposure, in terms of leading indicators of ignition probability and wildfire consequences.
Property	Private and public property, buildings and structures, infrastructure, and other items of value that are destroyed by wildfire, including both third-party property and utility assets.
PSPS event	Defined as the time period from the first public safety partner notified of a planned public safety de-energization to the final customer re-energized.
PSPS risk	The potential for the occurrence of a PSPS event expressed in terms of a combination of various outcomes of the event and their associated probabilities.
PSPS weather	Weather that exceeds a utility's risk threshold for initiating a PSPS.
Red Flag Warning (RFW)	Level of wildfire risk from weather conditions, as declared by the National Weather Service. For historical NWS data, refer to the Iowa State University Iowa archive of NWS watch / warnings.[2]
RFW OH Circuit Mile Day	Sum of overhead circuit miles of utility grid subject to Red Flag Warning each day within a given time period, calculated as the number of overhead circuit miles that are under an RFW multiplied by the number of days those miles are under said RFW. For example, if 100 overhead circuit miles are under an RFW for 1 day, and 10 of those miles are under RFW for an additional day, then the total RFW OH circuit mile days would be 110.

[2] https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml

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Risk event	An event with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition. The following risk events all qualify as risk events: • Ignitions • Outages not caused by vegetation • Vegetation-caused outages • Wire-down events • Faults • Other risk events with potential to cause ignitions
Risk event simulation	Simulation of what the consequence would have been of an ignition had it occurred.
Risk-spend efficiency (RSE)	An estimate of the cost-effectiveness of initiatives, calculated by dividing the mitigation risk reduction benefit by the mitigation cost estimate based on the full set of risk reduction benefits estimated from the incurred costs. For ongoing initiatives, the RSE can be calculated by determining the "marginal benefit" of additional spending in the ongoing initiative. For example, the RSE of an ongoing initiative could be calculated by dividing the mitigation risk reduction benefit from a 5% increase in spend by the cost associated with a 5% increase in spend.
Rule	Section of public utility code requiring a particular activity or establishing a particular threshold.
Run-to-failure	A maintenance approach that replaces equipment only when it fails.
Rural region	In accordance with GO 165, "rural" must be defined as those areas with a population of less than 1,000 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, "area" must be defined as census tracts.
Safety Hazard	A condition that poses a significant threat to human life or property.
Simulated wildfire	Propagation and impact/consequence of a wildfire ignited at a particular point ('match drop'), as simulated by fire spread software.
Slash	Branches or limbs less than four inches in diameter, and bark and split products debris left on the ground as a result of utility vegetation management. This definition is consistent with Public Resources Code Section 4525.7.
Span	The space between adjacent supporting poles or structures on a circuit consisting of electric lines and equipment. "Span level" refers to asset-scale granularity.
System Average Interruption Duration Index (SAIDI)	System-wide total number of minutes per year of sustained outage per customer served.
Third-party contact	Contact between a piece of electrical equipment and another object, whether natural (tree branch) or human (vehicle).
Time to expected failure	Time remaining on the life expectancy of a piece of equipment.
Top 30% of proprietary fire potential index	Top 30% of FPI or equivalent scale (*e.g.*, "Extreme" on SCE's FPI; "extreme", 15 or greater, on SDG&E's FPI; and 4 or above on PG&E's FPI).
Tree with strike potential / danger tree	A tree within or adjacent to the utility right-of-way that has a structural defect or lean that makes it likely to fail in whole or in part and contact electrical equipment or facilities.[3]
Unplanned outage	Electric outage that occurs with no advance notice from the utility (*e.g.*, blackout).

[3] "Danger tree" is more specifically defined in California Code of Regulation Title 14 § 895.1.

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Urban region	In accordance with GO 165, "urban" must be defined as those areas with a population of more than 1,000 persons per square mile as determined by the United States Bureau of the Census.
Utility-related ignitions	Ignitions involving utility infrastructure or employees, including all ignitions determined by AHJ investigation to originate from utility infrastructure or employees.
Vegetation management	Trimming, removal, and other remediations of vegetation used to maintain utility ROW and reduce the risk of outages, ignitions, and other disruption and danger.
Vegetation risk index	Risk index indicating the probability of vegetation-caused outages and/or ignitions along a particular circuit, based on the vegetation species, density, height, growth rate, etc.
Weather normalization	Adjusting metrics based on relative weather risk factors or indices.
Wildfire impact/ consequence	The effect or outcome of a wildfire affecting objectives, which may be expressed, by terms including, although not limited to health, safety, reliability, economic and/or environmental damage.
Wildfire risk	The potential for the occurrence of a wildfire event expressed in terms of ignition probability, wildfire impact/consequence.
Wildfire-only WMP programs	Activities, practices, and strategies that are only necessitated by wildfire risk, unrelated to or beyond that required by minimum reliability and/or safety requirements. Such programs are not indicated or in common use in areas where wildfire risk is minimal (*e.g.*, territory with no vegetation or fuel) or under conditions where wildfires are unlikely to ignite or spread (*e.g.*, when rain is falling).
Wildland urban interface (WUI)	A geographical area identified by the state as a “Fire Hazard Severity Zone”, or other areas designated by the enforcing agency to be a significant risk from wildfires, established pursuant to Title 24, Part 2, Chapter 7A.
Wire down	Instance where an electric transmission or distribution conductor is broken and falls from its intended position to rest on the ground or a foreign object.

1. PERSONS RESPONSIBLE FOR EXECUTING THE WMP

***Instructions*[4]*: Provide an accounting of the responsibilities of the responsible person(s) executing the plan, including:*

1. *Executive level with overall responsibility*
2. *Program owners specific to each component of the plan*

Title, credentials, and components of responsible person(s) must be released publicly, but other contact information may be provided in a redacted file attached to the WMP submission.

Executive-level owner with overall responsibility

- Name and title: Edward Jackson, President, California
- Email: [redacted]
- Phone number: [redacted]

Program owners specific to each section of the plan

Note: A program owner may own multiple sections, and multiple components across sections, but each section must have a program owner accountable.

Section 1: Persons responsible for executing the plan

Program owner (add additional program owners if separated by component in section):

- Name and title: Eliot Jones, Senior Manager, Wildfire Prevention
- Email[redacted]
- Phone number: [redacted]
- Component (if entire section, put “entire section”): Wildfire Prevention

- Name and title: Travis Johnson, Vice President, Operations
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put “entire section”): Operations

- Name and title: Blaine Ladd, Director, Operations
- Email[redacted]
- Phone number: [redacted]
- Component (if entire section, put “entire section”): Operations

Section 2: Adherence to statutory requirements

Program owner (add additional program owners if separated by component in section):

- Name and title: Dan Marsh, Senior Manager, Rates and Regulatory Affairs
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put “entire section”): Entire Section

[4] Text in orange text boxes are instructions from WSD/OEIS guidance.

- Name and title: Jordan Parrillo, Manager, Rates and Regulatory Affairs
- Email[redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Entire Section

Section 3: Actuals and planned spending

Program owner (add additional program owners if separated by component in section):

- Name and title: Eliot Jones, Senior Manager, Wildfire Prevention
- Email[redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Operations and Maintenance spending

- Name and title: Rick Dalton, Senior Director, Engineering
- Email[redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Capital spending

Section 4: Lessons learned and risk trends

Program owner (add additional program owners if separated by component in section):

- Name and title: Eliot Jones, Senior Manager, Wildfire Prevention
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Lessons learned

- Name and title: Rick Dalton, Senior Director, Engineering
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Risk trends

- Name and title: Jordan Parrillo, Manager, Rates and Regulatory Affairs
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Entire Section

Section 5: Inputs to the plan and directional vision

Program owner (add additional program owners if separated by component in section):

- Name and title: Eliot Jones, Senior Manager, Wildfire Prevention
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Wildfire Prevention

PERSONS RESPONSIBLE FOR EXECUTING THE WMP

- Name and title: Travis Johnson, Vice President, Operations
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Operations

- Name and title: Blaine Ladd, Director, Operations
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Operations

- Name and title: Rick Dalton, Senior Director, Engineering
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Planning

Section 6: Metrics and underlying data

Program owner (add additional program owners if separated by component in section):

- Name and title: Eliot Jones, Senior Manager, Wildfire Prevention
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Performance Metrics

- Name and title: Blaine Ladd, Director, Operations
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Performance Metrics

Section 7: Mitigation initiatives

Program owner (add additional program owners if separated by component in section):

- Name and title: Eliot Jones, Senior Manager, Wildfire Prevention
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Overall WMP; Situational Awareness and Forecasting; Data Governance

- Name and title: Blaine Ladd, Director, Operations
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Situational Awareness; PSPS; Grid Operations; Substation Improvements; Asset Management and Inspections

PERSONS RESPONSIBLE FOR EXECUTING THE WMP

- Name and title: Peter Stoltman, Manager, Vegetation Management
- Email:[redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Vegetation Management

- Name and title: Rick Dalton, Senior Director, Engineering
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Grid Design and System Hardening

- Name and title: Lindsay Maruncic, Senior Manager, Renewable Energy Assets
- Email:[redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Customer Resiliency Program

- Name and title: Leonard Kiolbasa, Manager, Emergency Management
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Emergency Planning and Preparedness

- Name and title: Kate Marrone, Manager, Business and Community Development
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Emergency Planning and Preparedness; Stakeholder Cooperation and Community Engagement

- Name and title: Alison Vai, Senior Manager, Marketing and Communications
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Stakeholder Cooperation and Community Engagement

- Name and title: Jordan Parrillo, Manager, Rates and Regulatory Affairs
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put "entire section"): Overall WMP; Risk

Section 8: Public Safety Power Shutoff

Program owner (add additional program owners if separated by component in section):

- Name and title: Eliot Jones, Senior Manager, Wildfire Prevention
- Email: [redacted]
- Phone number:[redacted]
- Component (if entire section, put "entire section"): Wildfire Prevention

PERSONS RESPONSIBLE FOR EXECUTING THE WMP

- Name and title: Travis Johnson, Vice President, Operations
- Email:[redacted]
- Phone number: [redacted]
- Component (if entire section, put “entire section”): Operations

- Name and title: Blaine Ladd, Director, Operations
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put “entire section”): Operations

- Name and title: Leonard Kiolbasa, Manager, Emergency Management
- Email:[redacted]
- Phone number: [redacted]
- Component (if entire section, put “entire section”): Emergency Planning and Preparedness

Section 9: Appendix

Program owner (add additional program owners if separated by component in section):

- Name and title: Dan Marsh, Senior Manager, Rates and Regulatory Affairs
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put “entire section”): Entire Section

- Name and title: Jordan Parrillo, Manager, Rates and Regulatory Affairs
- Email: [redacted]
- Phone number: [redacted]
- Component (if entire section, put “entire section”): Entire Section

PERSONS RESPONSIBLE FOR EXECUTING THE WMP

1.1. Verification

Complete the following verification for the WMP submission:

(See Rule 1.11)

(Where Applicant is a Corporation)

I am an officer of the applicant corporation herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on May 6, 2022 at Downey, California.
(Date) (Name of city)

Edward Jackson

Edward Jackson
President, California

2. ADHERENCE TO STATUTORY REQUIREMENTS

***Instructions**: Section 2 comprises a "check list" of the Pub. Util. Code § 8386 © requirements and subparts. The utility is required to both affirm that the WMP addresses each requirement AND cite the section and page number where statutory compliance is demonstrated fully. Citations are required to use cross-referencing with hyperlinks.*

Note: Energy Safety reserves the right to automatically reject a WMP that does not provide substantiation for statutory compliance or does not provide citations to appropriate sections of the WMP.

Table 2. 1 provides the full list of statutory requirements. A table similar to Table 2. 1 is required with the appropriate citation for each requirement. If multiple WMP sections address a specific requirement, then references to all relevant sections with a brief indication of information provided in each section must be provided. The table must include each section reference separated by semi-colon (e.g., Section 5, pg. 30-32 (workforce); Section 7, pg. 43 (mutual assistance)) where appropriate, and associated hyperlinks to the referenced section.

Table 2. 1: Statutory Compliance Matrix

Requirement	Description	WMP Section & Page Number
1	An accounting of the responsibilities of person(s) responsible for executing the plan	Section 1, pp. 13-17
2	The objectives of the plan	Section 5.1, pg. 76 Section 5.2, pp. 76-80 Section 7.1, pp. 95-102
3	A description of the preventive strategies and programs to be adopted by the electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks	Section 4.2.1, pp. 33-37 Section 4.5.1.1, pp. 62-64 Section 5.1, pg. 76 Section 5.2, pp. 76-80 Section 7.1, pp. 95-102 Section 7.3, pp. 103-176
4	A description of the metrics the electrical corporation plans to use to evaluate the plan's performance and the assumptions that underlie the use of those metrics	Section 4.5.2, pp. 71-73 Section 6, pp. 91-94
5	A discussion of how the application of previously identified metrics to previous plan performances has informed the plan	Section 4.1, pp. 25-29 Section 7.3, pp. 103-176
6	Protocols for disabling reclosers and de-energizing portions of the electrical distribution system that consider the associated impacts on public safety. As part of these protocols, each electrical corporation shall include protocols related to mitigating the public safety impacts of disabling reclosers and de-energizing portions of the electrical distribution system that consider the impacts on all of the aspects listed in PU Code 8386c	Section 7.3.3.9, pp. 116-117 Section 7.3.6.1, pp. 158-159 Section 7.3.6.2, pp. 159-160

ADHERENCE TO STATUTORY REQUIREMENTS

Requirement	Description	WMP Section & Page Number
7	Appropriate and feasible procedures for notifying a customer who may be impacted by the de-energizing of electrical lines, including procedures for those customers receiving a medical baseline allowance as described in paragraph (6). The procedures shall direct notification to all public safety offices, critical first responders, health care facilities, and operators of telecommunications infrastructure with premises within the footprint of potential de-energization for a given event	Section 7.3.9.3, pp. 168-170 Section 7.3.10.1, pp. 170-176 Section 8, pp.177-190
8	Identification of circuits that have frequently been de-energized pursuant to a de-energization event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by the electrical corporation to reduce the need for, and impact of, future de-energization of those circuits, including, but not limited to, the estimated annual decline in circuit de-energization and de-energization impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines	N/A
9	Plans for vegetation management	Section 7.3.5, pp. 125-158
10	Plans for inspections of the electrical corporation's electrical infrastructure	Section 7.3.4, pp. 121-125
11	Protocols for the de-energization of the electrical corporation's transmission infrastructure, for instances when the de-energization may impact customers who, or entities that, are dependent upon the infrastructure	Section 8, pp. 177-190
12	A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the electrical corporation's service territory, including all relevant wildfire risk and risk mitigation information that is part of the Safety Model Assessment Proceeding and the Risk Assessment Mitigation Phase filings	Section 4, pp. 25-37
13	A description of how the plan accounts for the wildfire risk identified in the electrical corporation's Risk Assessment Mitigation Phase filing	Section 4.2, pp. 30-37 Section 7.1, pp. 95-102
14	A description of the actions the electrical corporation will take to ensure its system will achieve the highest level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment, and facilities, such as undergrounding, insulation of distribution wires, and pole replacement	Section 7.3.4, pp. 121-125

ADHERENCE TO STATUTORY REQUIREMENTS

Requirement	Description	WMP Section & Page Number
15	A description of where and how the electrical corporation considered undergrounding electrical distribution lines within those areas of its service territory identified to have the highest wildfire risk in a commission fire threat map	Section 7.3.3.16, pp. 119-120
16	A showing that the electrical corporation has an adequately sized and trained workforce to promptly restore service after a major event, taking into account employees of other utilities pursuant to mutual aid agreements and employees of entities that have entered into contracts with the electrical corporation	Section 7.3.6.4, pp. 160-161 Section 7.3.9.1, pp. 165-166
17	Identification of any geographic area in the electrical corporation's service territory that is a higher wildfire threat than is currently identified in a commission fire threat map, and where the commission must consider expanding the high fire threat district based on new information or changes in the environment	Section 4.2.1, pp. 33-37 Section 7.1, pp. 95-102
18	A methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk that is consistent with the methodology used by other electrical corporations unless the commission determines otherwise	Section 4, pp. 25-37 Section 7.1, pp. 95-102
19	A description of how the plan is consistent with the electrical corporation's disaster and emergency preparedness plan prepared pursuant to Section 768.6, including plans to restore service and community outreach	Section 7.3.9, pp. 165-170
20	A statement of how the electrical corporation will restore service after a wildfire	Section 7.3.6.5, pp. 161-162
21	Protocols for compliance with requirements adopted by the commission regarding activities to support customers during and after a wildfire, outage reporting, support for low-income customers, billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, repair processing and timing, access to electrical corporation representatives, and emergency communications	Section 7.3.9.3, pp. 168-170
22	A description of the processes and procedures the electrical corporation will use to do the following: (A) Monitor and audit the implementation of the plan. (B) Identify any deficiencies in the plan or the plan's implementation and correct those deficiencies. (C) Monitor and audit the effectiveness of electrical line and equipment inspections, including inspections performed by contractors, carried out under the plan and other applicable statutes and commission rules.	Section 7.2, pp. 102-103 Section 4.6, pp. 73-75 Section 7.3.4.14, pp.124-125

3. ACTUAL AND PLANNED SPENDING FOR MITIGATION PLAN

3.1. ACTUAL AND PLANNED SPENDING FOR MITIGATION PLAN

***Instructions**: Table 3.1- 1 summarizes the projected costs per year over the three-year WMP cycle, including actual expenditures for past years. Table 3.1- 2 breaks out projected costs per category of mitigations over the three-year WMP plan cycle. In reporting "planned" expenditures, use data from the corresponding year's WMP or WMP Update (i.e., 2020 planned expenditure must use 2020 WMP data). The financials represented in the summary tables below equal the aggregate spending listed in the mitigations financial tables reported quarterly. Nothing in this document is required to be construed as a statement that costs listed are approved or deemed reasonable if the WMP is approved, denied, or otherwise acted upon.*

Table 3.1- 1: Summary of WMP Expenditures - Total

	Expenditures ($000)
2020 Planned	$30,699
2020 Actual	$33,514
2020 Difference	$2,815
2021 Planned	$52,007
2021 Actual	$33,568
2021 Difference	$(18,439)
2022 Planned	$55,126
2020-2022 Planned (With 2020 and 2021 Actual)	$122,208

ACTUAL AND PLANNED SPENDING FOR MITIGATION PLAN

Table 3.1- 2: Summary of WMP Expenditure by Category

WMP Category	2020			2021			2022	2020-2022 Planned (w/ 2020 and 2021 Actuals)
	Planned	Actual	△	Planned	Actual	△	Planned	
Risk and Mapping	$-	$67	$67	$10	$53	$43	$55	$175
Situational Awareness	$450	$445	$(5)	$295	$282	$(13)	$315	$1,042
Grid Design and System Hardening	$13,241	$15,507	$2,266	$32,905	$19,642	$(13,263)	$32,712	$67,861
Asset Management and Inspections	$7,259	$3,842	$(3,416)	$2,977	$1,643	$(1,334)	$5,250	$10,735
Vegetation Management	$8,770	$12,685	$3,915	$13,580	$10,567	$(3,013)	$14,077	$37,328
Grid Operations	$-	$371	$371	$548	$398	$(150)	$450	$1,219
Data Governance	$665	$1	$(664)	$418	$111	$(306)	$520	$632
Resource Allocation	$-	$-	$-	$124	$311	$187	$300	$611
Emergency Planning	$240	$502	$262	$900	$460	$(440)	$1,304	$2,266
Stakeholder Cooperation and Community Engagement	$75	$92	$17	$251	$102	$(149)	$144	$338
Total	$30,699	$33,514	$2,815	$52,007	$33,568	$(18,439)	$55,126	$122,208

3.2. Summary of Ratepayer Impact

Instructions*: For each of the years in Table 3.2- 1, report the actual and projected cost increases to ratepayers due to utility-related ignitions and wildfire mitigation activities engaged. For past years, account for all expenditures incurred in that year due to utility-related ignitions and wildfire mitigation activities. Below the table, describe the methodology behind the calculations.*

Table 3.2- 1: WMP Electricity Cost Increases to Ratepayers

Outcome Metric Name	Annual performance						Unit(s)
	Actual					Projected	
	2017	2018	2019	2020	2021	2022	
Increase in electric costs to ratepayer due to utility-related ignitions (total)	$0	$0	$0	$0	$0	$0	Dollar value of average monthly rate increase attributable to utility-related ignitions per year (*e.g.*, $3/month on average across customers for utility-related ignitions occurring in 20XX)
Increase in electric costs to ratepayer due to wildfire mitigation activities (total)	$0	$0	$0	$0	$0	$18.35	Dollar value of average monthly rate increase attributable to WMPs per year

Methodology for electricity costs increase calculation:

For actual costs, Liberty interprets the category of “increase in electric costs to ratepayer due to wildfire mitigation activities” to include wildfire mitigation costs that have been reviewed by the Commission and included in rates. The increases do not include wildfire mitigation activity costs that are either still under review, that will be reviewed by the Commission for later cost recovery or are otherwise not currently included in rates.

For projected 2022 costs, Liberty calculated the average expected bill increase in 2022 attributable to wildfire mitigation activities based on the ratio of proposed 2022 wildfire-related capital and O&M expenses to the authorized revenue requirement. The resulting percentage increase of 17% due to wildfire mitigation activities was applied to an average monthly residential bill.

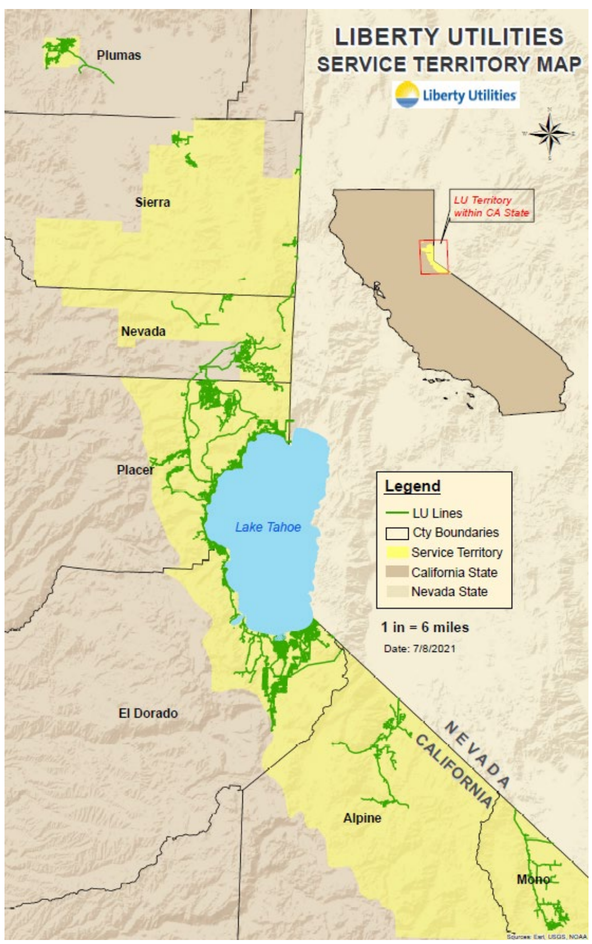
4. LESSONS LEARNED AND RISK TRENDS

4.1. Lessons Learned: how tracking metrics on the 2020 and 2021 plans informed the 2022 plan update

***Instructions**: Describe how the utility's plan has evolved since the 2020 WMP and 2021 WMP Update submissions. Outline any major themes and lessons learned from the 2020 and 2021 plans, and subsequent implementation of the initiatives. In particular, focus on how utility performance against the metrics used has informed the 2022 WMP Update. Include an overview map of the utility's service territory. If any of the lessons learned are derived from data, include visual/graphical representations of this/these lesson(s) learned.*

Liberty's WMP is an actionable plan that is being fully implemented and integrated into Liberty's daily operations and will be an effective source to track risk reduction and improve efficiency through innovative system technologies. Liberty's wildfire mitigation efforts have continued to be developed across all WMP categories since the submission of its 2021 WMP Update. Areas of focus include continued grid hardening initiatives, increased use of situational awareness tools, enhancement of data collection and analytics to inform reporting, risk modeling and decision-making, improvement of asset management and inspections processes, and increased preparedness for Public Safety Power Shutoff ("PSPS") events. As Liberty's wildfire mitigation efforts continue to advance, Liberty monitors and evaluates the implementation of its WMP initiatives. Key lessons learned are included below.

Figure 4. 1: Overview Map of Liberty's Service Territory



LESSONS LEARNED AND RISK TRENDS

Table 4. 1: Major Themes and Lessons Learned from 2020 and 2021 WMP and Implementation of Plan

WMP Category	Major themes and lessons learned in 2020 and 2021	Subsequent implementation of initiatives
Risk Assessment and Mapping	The fire risk map and circuit risk analysis can be utilized as the baseline for Liberty's wildfire risk assessment. The designated high Reax wildfire areas can be used by operations and engineering for planning of wildfire mitigation work. Liberty participates in the Joint IOU Wildfire Risk Modeling Working Group to understand best practices across the California IOUs regarding the following topics: • Modeling baselines • Fire consequence • Asset risk events and ignitions • Vegetation risk events and ignitions • PSPS likelihood • PSPS consequence and reliability analysis and impacts • Modeling algorithms, components, and interdependencies • Smoke and suppression impacts • Climate change impacts and ingress/egress	In 2022, Liberty is: • Continuing to develop its risk modeling team and capabilities; • Working with Reax to update its wildfire risk model and fire risk map and expand the underlying dataset to include statewide outages and ignitions; • Refreshing data inputs (*i.e.* pole risk, vegetation risk, grid hardening mitigations) to its circuit risk analysis; and • Participating in the Joint IOU Wildfire Risk Modeling Working Group to understand best practices across the California IOUs. Liberty will continue to utilize the fire risk map and circuit risk analysis to inform discussions and decisions regarding prioritizing WMP initiative work.
Situational Awareness	Continuous monitoring tools, such as Fire Potential Index ("FPI"), and installation of fault detection equipment has allowed Liberty to develop initial work processes and PSPS plans to monitor and adjust operations based on adverse conditions. Ongoing operational planning that fully utilizes real-time weather data, fault detection anomalies, and predictive wildfire assessment tools are in the early phases of full integration into Liberty work processes. Planning and incorporating an effective situational awareness plan requires an interactive system of data collection, analysis, and work planning.	The collection of data needs to be analyzed, and business processes are currently in the development phase for full integration of an interactive system of data collection, analysis, and work planning.
Grid Design and System Hardening	Liberty did not meet all 2021 WMP targets (*e.g.*, covered conductor, pole replacements, fuse replacements, tree attachment removals) for this category primarily because the Tamarack and Caldor fires significantly impacted line construction resource availability and supply chain issues impacted material availability.	Liberty started design work earlier than in the past so that materials can be ordered early enough to be available for planned construction schedules. Design work for 2023 projects is currently in progress and design work for future years will be started even earlier. There are still significant issues with supply chain, including long lead times to obtain transformers. Liberty is finding alternative suppliers, materials and methods to acquire materials needed. In addition, covered conductor projects delayed from 2021 have rolled into 2022

WMP Category	Major themes and lessons learned in 2020 and 2021	Subsequent implementation of initiatives
		for completion. These projects have high assurance for completion without delays.
Asset Management and Inspections	The system survey that Liberty completed in 2020 generated a significant number of G.O. 95-related repairs that Liberty is working to complete. The survey also revealed that not all field changes had been tracked in an accurate or timely manner and that improvements to those processes needed to be made so the system maintains a high level of accuracy. Liberty understands that ground-based inspections have limitations, which is why it is considering other technologies, such as infrared inspections, to enhance inspection practices. In the future, should Liberty embark on a full system survey, the system will be surveyed over two years instead of one.	Liberty is continuing to work on repairs found during the 2020 full system survey, prioritizing repairs by G.O. 95 level and wildfire risk, where applicable. Liberty has reverted to a five-year schedule for G.O. 165 inspections and developed an asset inspection QA/QC program. Substation inspections will continue to be performed on a quarterly basis.
Vegetation Management and Inspections	Liberty has recognized the importance of utilizing emerging technology to make data-driven and risk-informed decisions to prioritize vegetation management work. In 2020, Liberty piloted LiDAR inspections on its South Lake Tahoe circuits to identify and mitigate encroachments. Liberty implemented LiDAR inspections on its entire service territory in 2021 to continue to efficiently manage tree clearances. Liberty intends to explore use cases for tree health monitoring and further risk analysis utilizing LiDAR technology. Liberty successfully implemented its formalized QC program to verify effectiveness of vegetation management practices in 2021. Liberty also made notable achievements in fuel management work by removing more than 2,100 tons of additional biomass from the landscape. Liberty's portfolio of vegetation management initiatives operates together to provide a defense in depth strategy to efficiently manage vegetation and risks associated along its system.	Liberty intends to continue LiDAR inspections of vegetation around electric facilities on an annual basis to manage tree encroachments. Liberty is exploring using LiDAR technology to identify locations affected by tree mortality and other vegetation and location risk factors. Liberty will continue to monitor change detection on an annual basis to recognize workload trends and to inform program decisions. Liberty will continue to streamline efficiencies and the integration of its portfolio of vegetation initiatives to cooperatively manage vegetation along its system.
Grid Operations and Operating Protocols	In 2020 and 2021, Liberty developed, implemented, and improved PSPS operations and communications protocols. These protocols, in combination with the development of the FPI and PSPS forecasting tools have helped to inform day-to-day operational decision-making. While Liberty did not initiate any PSPS events in 2021, Liberty did activate its	Liberty continually looks to improve FPI and PSPS forecast accuracy and will incorporate additional model forecast data into the existing tools where possible. In 2022, Liberty will utilize both PSPS decision-trees discussed in Section 8.3.

WMP Category	Major themes and lessons learned in 2020 and 2021	Subsequent implementation of initiatives
	Emergency Operations Center ("EOC") in September 2021 to begin coordinating response operations associated with an elevated weather event with the potential for employment of Liberty's PSPS protocol. In addition to considering the input from Liberty's fire science consultant, Reax, which monitored available weather data, Liberty mobilized on-the-ground resources to patrol and assess local conditions. These circuit crews provided input based on real-time risk assessments in the field. In addition to real-time weather conditions, the EOC reviewed and considered local system conditions, input from public safety partners, alternatives to de-energization, and mitigation options.	In 2022, Liberty is embarking on a Distribution Automation pilot program. Liberty will continue to explore the use of fast trip/one-shot setting during high fire threat days to limit energy to overhead faults and minimize the chance of ignition. Liberty is looking at fault detection with communications to determine more quickly the location of a fault when using fast trips to mitigate larger or longer outages.
Data Governance	The results of the full system survey asset inventory completed in 2020 provided the basis for an asset management system that can be used for prioritizing future work based on wildfire risk modeling and fire risk maps and can enable Liberty to respond to infractions with increased speed, volume, and improved accuracy. Throughout 2021, Liberty continued to improve protocols and train its staff on digital field collection forms and integrating data sources that will assist Liberty to further leverage data governance upgrades and adoption of new technologies.	Liberty's overall goal is to develop an integrated data management and reporting solution to improve data consistency and efficiencies internally and for the WMP reporting process. Liberty has three major software upgrades underway that will impact this initiative, including upgrades to its Geographic Information System ("GIS"), Outage Management System ("OMS"), and Responder database. In designing a solution that considers these major system upgrades and integrates with all current data sources, Liberty has initiated conversations and requests for information with consultants offering data analytics solutions. Liberty looks to expand its technical staffing, training, and wider IT involvement in order to help manage continuous process improvements while balancing the use of external resources.
Resource Allocation Methodology	In 2021, Liberty re-evaluated its risk modeling data inputs and assumptions based on discussions with subject matter experts ("SMEs". Liberty uses its circuit risk analysis and fire risk mapping tool to inform planning and prioritize work in WMP initiatives and strives to understand all model parameters. The re-evaluation included refining data inputs and assessments of wildfire risk for defining tree risk and pole risk. Risk Spend Efficiency ("RSE") calculations are a useful tool to inform the decision-making process when evaluating initiatives or alternative mitigations. RSEs are only one factor in developing Liberty's wildfire risk mitigation strategies.	Liberty will utilize RSE calculations as one component in overall WMP planning and long-term decision-making.

LESSONS LEARNED AND RISK TRENDS

WMP Category	Major themes and lessons learned in 2020 and 2021	Subsequent implementation of initiatives
Emergency Planning and Preparedness	In 2021, Liberty implemented four major activations of its Emergency Operations Plan. Activations occurred in response to the Tamarack Fire on July 16, the Caldor Fire on August 30, a potential PSPS on September 16, and a winter storm response on December 23. Major themes and lessons learned in 2020 and 2021 included the following: • Include Regulatory Affairs as part of the Incident Management Team ("IMT") to report to regulatory agencies. • Streamline Incident Command meetings by briefing operations first to develop an action plan prior to meeting with the entire IMT. • Consolidate the Operations and Communications playbooks into a single playbook. • Develop a method to confirm Medical Baseline ("MBL") customer notifications.	The IMT chart now includes a Regulatory Affairs Liaison. IMT meetings have been streamlined beginning with the winter storm response in December 2021. The consolidation of the Operations and Communications playbooks is ongoing. Procedures have been developed to confirm notification of MBL customers or provide in-person notifications.
Stakeholder Cooperation and Community Engagement	In 2021, Liberty launched a digital ad campaign specific to wildfire mitigation and PSPS preparation and awareness. Topics included defensible space, emergency preparedness, medical baseline program information, general PSPS information and preparation tips, communication of PSPS public workshops and the importance of updating contact information in Liberty systems to enable PSPS and emergency notifications. A major lesson learned for Liberty throughout 2020 and 2021 was that the engagement of Community Based Organizations and Public Safety Partners is essential to reaching and preparing customers and stakeholders for potential PSPS events. An increased focus on these relationships and communication has driven Liberty's resource additions and bandwidth to perform additional outreach, feedback collection, and networking. More positions were added in 2021 to expand CBO relationship networks and communications channels, including a bilingual Outreach Coordinator.	Liberty will continue these increased engagement efforts throughout 2022. CBO feedback gathered through surveys has informed the 2022 outreach and communications approach in a few ways, including highlighted effectiveness of increased use of email and local media driving website traffic to existing PSPS information. Increased messaging around preparation of emergency kits and readiness is also a focus for Liberty in 2022. Liberty has found CBO partnerships beneficial in sharing information and connecting to local resources for AFN resource awareness, PSPS preparedness, and program awareness resulting in a continued focus to expand these networks in 2022.

4.2. Understanding major trends impacting ignition probability and wildfire consequence

***Instructions**: Describe how the utility assesses wildfire risk in terms of ignition probability and estimated wildfire consequence, including use of Multi-Attribute Risk Score (MARS) and Multi-Attribute Value Function (MAVF) as in the Safety Model and Assessment Proceeding (S-MAP)[5] and Risk Assessment Mitigation Phase (RAMP), highlighting changes since the 2020 WMP and 2021 Update. Include description of how the utility distinguishes between these risks and the risks to safety and reliability. List and describe each "known local condition" that the utility monitors per GO 95, Rule 31.1, including how the condition is monitored and evaluated.*

Liberty modeled its risk-based decision-making ("RBDM") methodology on both the larger IOUs' structure and the Commission's guidance during the RAMP and S-MAP proceedings. Liberty filed its General Rate Case ("GRC") with its RBDM methodology and results demonstrated significant improvements since filing its 2020 WMP and 2021 Update. Liberty's risk assessment team continues to evaluate and refine the methods in the IOU's RBDM framework, while also addressing each requirement in the CPUC's Voluntary Agreement in the RBDM Decision (D.19-04-020).

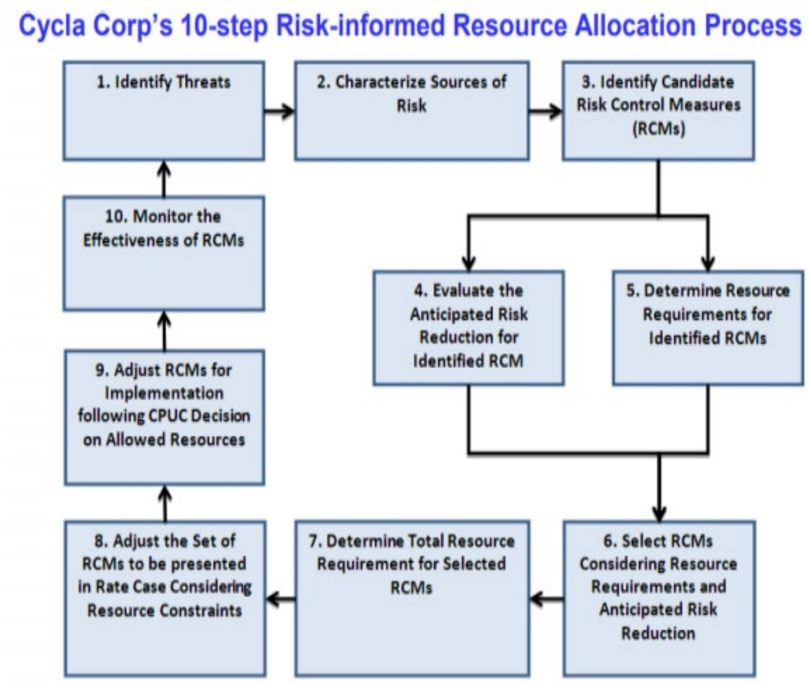
Liberty utilizes the Multi-Attribute Risk Score ("MARS") and Multi-Attribute Value Function ("MAVF") methodologies in its wildfire risk modeling. Each of these methods properly converts natural units of risk reduced to standardized risk units reduced, allowing a direct comparison of controls and/or mitigations. Liberty's models align with the larger IOUs' RBDM frameworks, as these frameworks put Liberty in a better position to leverage the improvements the Commission and the larger IOUs make in evaluating and benchmarking modeling frameworks.

Liberty's Risk-Based Decision-making Framework

Liberty's Enterprise Risk Management ("ERM") process consists of an iterative process cycle of identifying, assessing, mitigating, and communicating risks. Risks are identified using a top-down and a bottom-up approach to classify the greatest areas of concern. Consistent with the Commission's guidance, Liberty follows the principles and processes developed by Cycla Corporation ("Cycla") in its 10-step risk management process, as shown in Figure 4. 2.

[5] Updates to S-MAP are currently in deliberation in R. 20-07-013 – Order Instituting Rulemaking to Further Develop a Risk-based Decision-making Framework for Electric and Gas Utilities.

Figure 4. 2: Cycla 10-step Risk-informed Resource Allocation Process



Liberty's risk management process is based on the Cycla process shown above and involves the following steps:

1. Risk identification – includes brainstorming sessions with operations managers and engineering to develop Liberty's risk register;
2. Analysis - assigns appropriate risk ownership within the organization, develops worst-case scenarios, likelihood of events, and analysis of impacts;
3. Evaluation and Prioritization - includes scoring to focus on the most significant impact to safety and reliability;
4. Risk Mapping and Modeling - uses various software to illustrate and quantify risk reduction from mitigation portfolios;
5. Risk-Informed Investment Decisions and Implementation - develops risk reduction mitigation plans and incorporates risk mitigation in capital and operating plans; and
6. Risk Monitoring: establishes controls to monitor risks.

<u>Liberty's Wildfire Risk Analysis and Assessment</u>

Liberty assesses wildfire risk through various levels of analysis. First, ignition probability risk was conducted by Reax Engineering, Liberty's wildfire science consultant. Reax assessed the probability of ignitions occurring using Liberty's historic forced outages from January 2017 through October 2021. This assessment is a new enhancement to Liberty's wildfire risk analysis that feeds directly into Reax's fire propagation model for estimating wildfire consequences. Next, Reax analyzes its simulated burn, match-drop simulations that assesses factors such as the 24-hour continuous burn simulations, structures destroyed, commercial value of buildings destroyed, timber destroyed, fire suppression costs, and anticipated population affected by serious injuries or death. These factors are reviewed independently of Liberty's asset risk and tree risk, and risk profiles are then created in the service territory based on the factors mentioned above and the location of Liberty's primary overhead lines. Lastly, Liberty creates its various risk tranches in its service territory based on the merged information of the simulated wildfire consequence modeling, asset inspection data, and its vegetation management analysis in order to form a holistic profile of wildfire risk by region.

Wildfire risk is reviewed separately from public safety, employee/contractor safety, or distribution asset performance in Liberty's RBDM framework. Liberty has produced wildfire risk models to calculate RSEs modeled in the same fashion as in the RAMP/S-MAP proceedings. The public safety, employee/contractor safety, and distribution asset performance risks will be separated into three distinguishable risk groups, exclusive of how Liberty models wildfire risk. Liberty is in the process of updating the RBDM model calculations to refine its estimated effectiveness percentages using information gathered from risk modeling working group discussions and will provide updated RSE calculations when available.

Liberty designs, constructs, and maintains facilities in accordance with G.O. 95, as well as in accordance with known local conditions that require a higher standard than specified in G.O. 95 to enable the furnishing of safe, proper, and adequate service. Specifically, because Liberty's service territory is over 6,000 feet above sea level, Liberty adheres to Grade A - Heavy Loading District construction, per G.O. 95, Rule 43.1.

A. *Describe how the utility monitors and accounts for the contribution of weather to ignition probability and estimated wildfire consequence in its decision-making, including describing any utility-generated Fire Potential Index or other measure (including input variables, equations, the scale or rating system, an explanation of how uncertainties are accounted for, an explanation of how this index is used to inform operational decisions, and an explanation of how trends in index ratings impact medium-term decisions such as maintenance and longer-term decisions such as capital investments, etc.).*

Liberty's recent ignition probability model incorporates Real-Time Mesoscale Analysis ("RTMA") weather data that provides hourly resolution wind speed direction gridded on Liberty's service territory using geospatial data. The historic weather data is similar to weather station observations and serves to model weather patterns for real world conditions and can be analyzed at the resolution of 2.5 meter plots. Liberty's historic outage data frequency was analyzed using the historic weather data to factor variables in weather characteristics to correlate outage frequency by weather attributes for temperature or wind speeds. Liberty describes the weather analysis in Section 4.5.1.3.

Refer to Section 4.5.1.3, which explains Liberty's Fire Potential Index ("FPI") and how Liberty monitors and adjusts work conditions based on weather.

B. *Describe how the utility monitors and accounts for the contribution of fuel conditions to ignition probability and estimated wildfire consequence in its decision-making, including describing any proprietary fuel condition index (or other measures tracked), the outputs of said index or other measures, and the methodology used for projecting future fuel conditions. Include discussion of measurements and units for live fuel moisture content, dead fuel moisture content, density of each fuel type, and any other variables tracked. Describe the measures and thresholds the utility uses to determine extreme fuel conditions, including what fuel moisture measurements and threshold values the utility considers "extreme" and its strategy for how fuel conditions inform operational decision-making.*

Seasonal variations in fuel moisture conditions are tracked through a combination of analytical methods and field-based fuel moisture sampling. For the former, observed and forecasted Energy Release Component ("ERC") percentiles from the USFS Wildland Fire Assessment System ("WFAS") are used to monitor intermediate to long-term fuel dryness. The data is generated from Remote Automated Weather Station ("RAWS") observations and the National Weather Service ("NWS") National Digital Forecast Database ("NDFD"). WFAS data is supplemented with in-situ fuel moisture sampling. In 2021, weekly fuel moisture sampling was conducted and sampling locations were expanded to additional sites in the Southern (Topaz/Walker) and Northern (Portola/Sierra Brooks) parts of Liberty's service territory. Fuel moisture sampling is targeted at values that are most difficult to accurately calculate from weather observations, including 1,000-

hour dead fuel moisture, live woody fuel moisture, and foliar moisture content. These readings serve as a check on the automated WFAS ERC percentiles and inform fire behavior calculations that are conducted when adverse weather conditions are forecast to occur.

4.2.1. Service territory fire threat evaluation and ignition risk trends

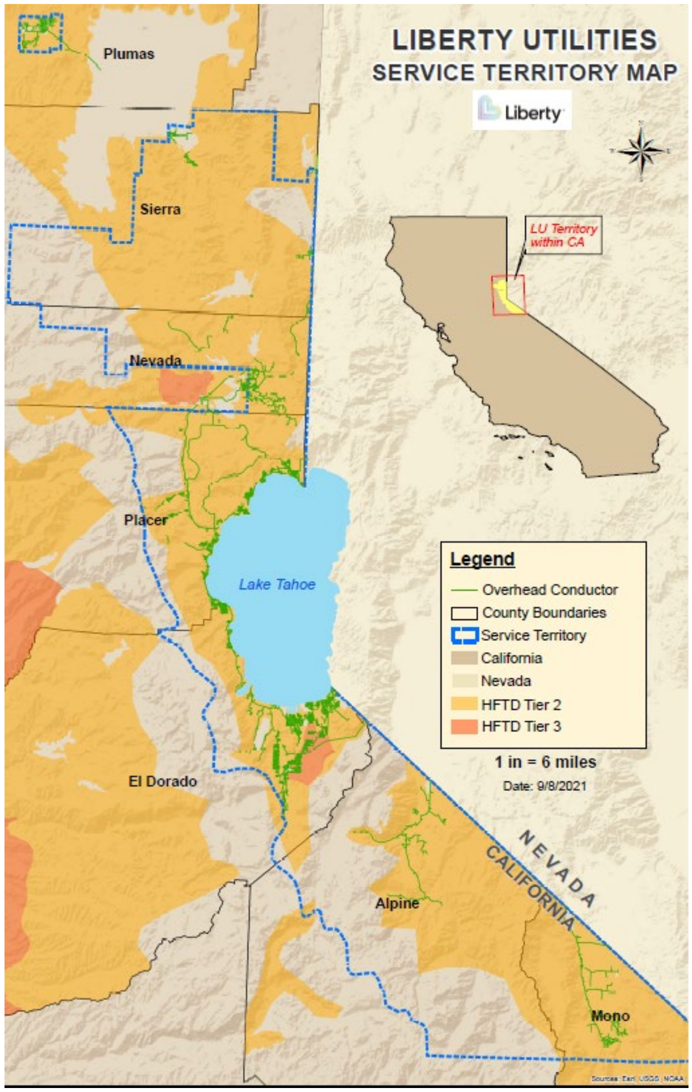
Instructions*: Present a map of the highest risk areas identified within the current High Fire Threat District (HFTD) tiers of the utility's service territory as a figure in the WMP. Discuss fire threat evaluation of the service territory to determine whether a modification to the HFTD is warranted (i.e., expansion beyond existing Tier 2 and Tier 3 areas). If the utility believes there are areas in its service territory that are not currently included in the HFTD but require prioritization for mitigation efforts, then the utility is required to provide a process outlining the formal steps necessary to have those areas considered for recognition in the CPUC-defined HFTD.*[6] *Include a discussion of any fire threat assessment of its service territory performed by the electrical corporation, highlighting any changes since prior WMP submissions. In the event that the utility's assessment determines the fire threat rating for any part of its service territory is insufficient (i.e., the actual fire threat is greater than what is indicated by the CPUC's Fire Threat Map and High Fire Threat District designations), the utility is required to identify those areas for potential HFTD modification, based on the new information or environmental changes, showing the differences on a map in the WMP. To the extent this identification relies upon a meteorological or climatological study, a thorough explanation and copy of the study must be included as an Appendix to the WMP.*

List, describe, and map geospatially (where geospatial mapping is applicable) any macro trends impacting ignition probability and estimated wildfire consequence within utility service territory, highlighting any changes since the 2021 WMP Update:

1. *Change in ignition probability and estimated wildfire consequence due to climate change*
2. *Change in ignition probability and estimated wildfire consequence due to relevant invasive species, such as bark beetles*
3. *Change in ignition probability and estimated wildfire consequence due to other drivers of change in fuel density and moisture*
4. *Population changes (including Access and Functional Needs population) that could be impacted by utility ignition*
5. *Population changes in HFTD that could be impacted by utility ignition*
6. *Population changes in WUI that could be impacted by utility ignition*
7. *Utility infrastructure location in HFTD vs non-HFTD*
8. *Utility infrastructure location in urban vs rural vs highly rural areas*

[6] Because there is no formal or standard process for modifying the HFTD maps defined by the CPUC, utilities may utilize a similar approach adopted by SCE during the 2019 WMP review process described in D.19-05-038, p. 53. For this process, in August 2019 SCE submitted a petition to modify D.17-12-024 to recognize SCE-identified HFRA as HFTD Tier 2 areas.

Figure 4.2.1- 1: Liberty's HFTD Map



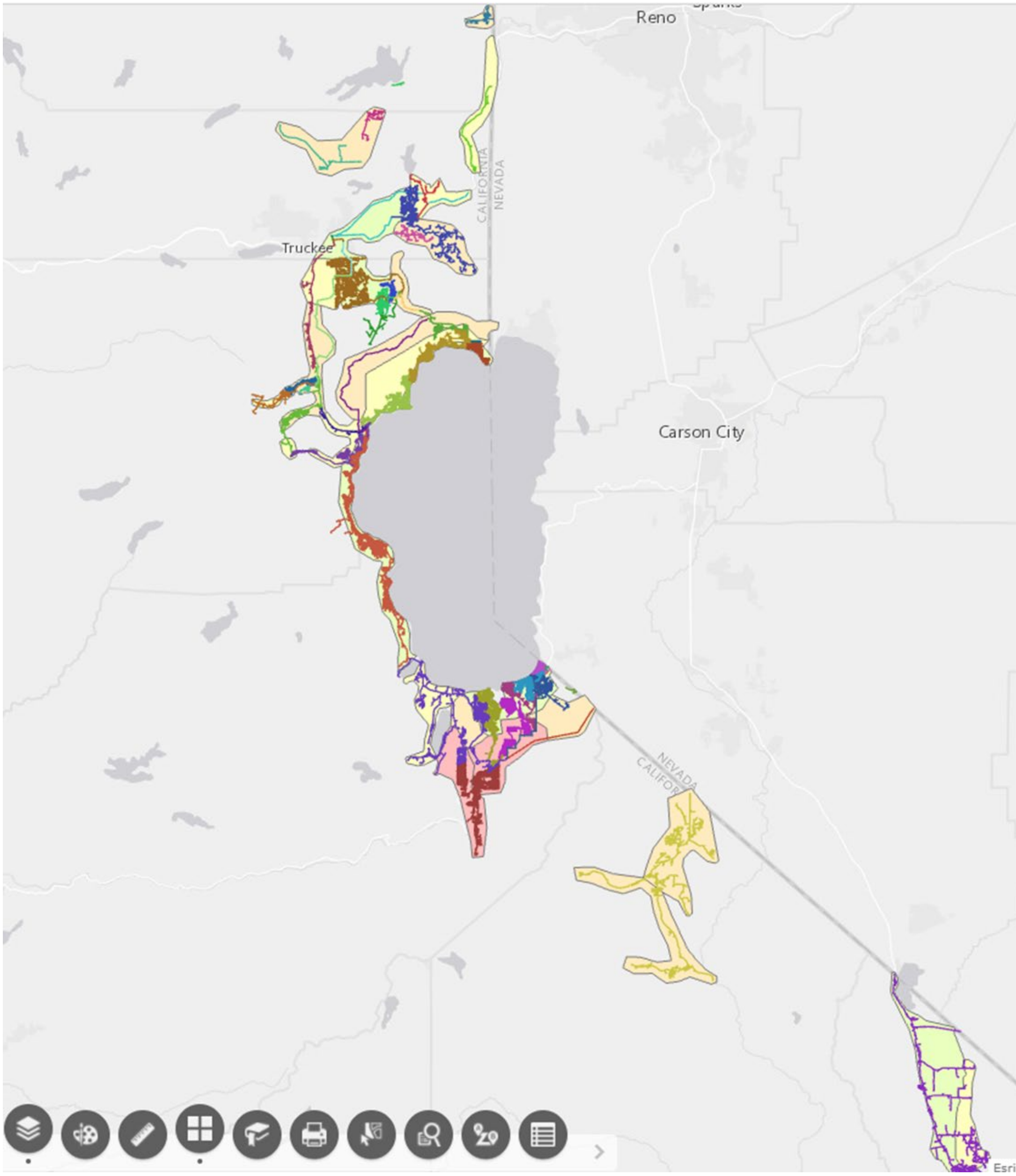
Liberty commissioned Reax to increase the precision and accuracy of assessing wildfire risk in Liberty's service territory. As part of Reax's analysis of wildfire conditions risk, Reax modeled the effects of simulated fires, or its fire propagation model, and observed the consequences of fire spread given location-specific fuels, humidity, tree canopy, and wind patterns.

The fire risk quantification methodology converts environmental, statistical, and scientific data into graphic regions of elevated fire risk from utility infrastructure. Presently, approximately 92% of Liberty's service territory lies within HFTD Tiers 2 and 3. Reax's analysis further defines HFTD Tier 2 areas into four distinct risk profiles: Low, Moderate, High, and Very High. See Liberty's Wildfire Risk Map below (Figure 4.2.1- 2: Liberty's Wildfire Risk MapFigure 4.2.1- 2) for the current risk rating Liberty used in its 2022 WMP initiative analysis and prioritization.

<u>**Polygon Risk Rating**</u>:

- Green – Low Wildfire Risk
- Yellow – Moderate Wildfire Risk
- Peach – High Wildfire Risk
- Salmon – Very High Wildfire Risk

Figure 4.2.1- 2: Liberty's Wildfire Risk Map



Since the wildfire polygons were first developed in 2020, Liberty's highest priority mitigation planning has been in the South Lake Tahoe region because of its very high fire risk rating. The wildfire risk rating signifies that, in the unlikely event a fire is ignited in this region, the simulated acres burned and number of structures lost for both residential and commercial given the fuel density in the area, low humidity, and historic wind patterns is projected to have higher consequences and thus higher wildfire risk. Absent this analysis, Liberty had initiated planning of long-lead time projects such as covered conductor projects in this region in 2020 to start in 2021-2022. Similarly, in January 2021, Liberty commissioned an independent microgrid feasibility study to be performed in this region to evaluate potential microgrid locations combined with segmented covered conductor lines versus installing all covered conductor per evaluated site.

LESSONS LEARNED AND RISK TRENDS

Liberty utilizes the Reax fire maps to assess wildfire risk and to serve as the baseline risk map for Liberty's circuit risk analysis. As new data becomes available affecting historic weather patterns, fuel density, moisture levels, Liberty will update the fire propagation model and fire risk mapping accordingly. Please see Table 4.2.1- 1 below for a list of macro trends impacting ignition probability and/or wildfire consequence.

Table 4.2.1- 1: Macro Trends Impacting Ignition Probability and/or Wildfire Consequence

Rank	Macro trends impacting utility ignited ignition probability and estimated wildfire consequence by year 10	Comments
1	Change in ignition probability and estimated wildfire consequence due to climate change	Reduction in live and dead fuel moisture values relative to the historical baseline correlate with increased fire severity. Tree mortality induced by climate change may increase ignitions associated with trees contacting power lines. Hotter summers with drought conditions and more extremes in the winter may also contribute to change in ignition probability.
5	Change in ignition probability and estimated wildfire consequence due to relevant invasive species, such as bark beetles	Tree mortality induced by disturbances, such as bark beetles, may increase ignitions associated with trees contacting power lines. The relationship between tree mortality and fire behavior is not clear and remains an active research area. Vegetation, such as cheatgrass, has taken over native grasslands and is highly flammable.
2	Change in ignition probability and estimated wildfire consequence due to other drivers of change in fuel density and moisture	Over 100 years of fire suppression and exclusion have contributed to higher fuel loading, which results in a shift from frequent, low intensity fires that benefit the landscape to periodic, intense fires that have negative effects.
7	Population changes (including Access and Functional Needs population) that could be impacted by utility ignition	This macro trend was interpreted to refer to aging population and individuals with limited mobility and/or cognitive impairments and how they could be impacted by utility-caused ignitions. Because urban populations are relatively scarce, this macro trend is not viewed as a major driver of fire consequence in Liberty's service territory.
8	Population changes in HFTD that could be impacted by utility ignition	Future demographic trends are unknown, and a macro trend is not considered a major driver of fire consequence in Liberty's service territory.

Rank	Macro trends impacting utility ignited ignition probability and estimated wildfire consequence by year 10	Comments
6	Population changes in WUI that could be impacted by utility ignition	Structures in Wildland Urban Interface or Intermix are more vulnerable to fire losses than those in urbanized areas. As more structures are built in WUI/Intermix areas, fire losses from all causes, not just utility ignitions, may increase.
3	Utility infrastructure location in HFTD vs. non-HFTD	As additional utility infrastructure is added to HFTD areas to serve new development, ignition probability may increase due to the presence of utilities in areas that previously had no utility infrastructure. This increase in ignition probability could potentially be partially offset by improved real-time monitoring of circuits and fire prevention measures, including de-energization under appropriate circumstances.
4	Utility infrastructure location in urban vs. rural vs. highly rural areas	As more structures are built and connected to the grid in rural and highly rural areas, increased presence of utilities in areas that previously contained no utilities may increase ignition probability. This increase in ignition probability could potentially be partially offset by improved real-time monitoring of circuits and other fire prevention measures, including de-energization under appropriate circumstances.

4.3. Change in ignition probability drivers

***Instructions**: Based on the implementation of the above wildfire mitigation initiatives, explain how the utility sees its ignition probability drivers evolving over the 3-year term of the WMP, highlighting any changes since the 2021 WMP Update. Focus on ignition probability and estimated wildfire consequence reduction by ignition probability driver, detailed risk driver, and include a description of how the utility expects to see incidents evolve over the same period, both in total number (of occurrence of a given incident type, whether resulting in an ignition or not) and in likelihood of causing an ignition by type. Outline methodology for determining ignition probability from events, including data used to determine likelihood of ignition probability, such as past ignition events, number of risk events, and description of events (including vegetation and equipment condition).*

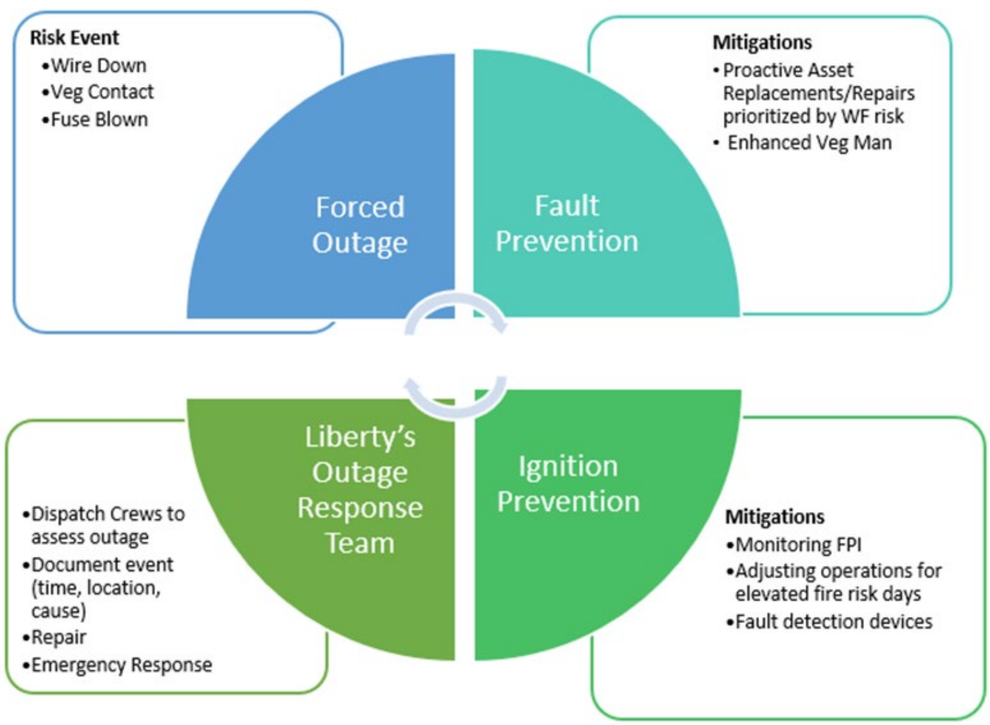
Prior to 2020, many of Liberty's operational work activities were compliance-driven and routine and generally did not exceed regulatory requirements. With the implementation of Liberty's 2020 WMP and 2021 Update, Liberty has enhanced its wildfire mitigation efforts by expanding vegetation management programs to include LiDAR tree inspections and analytics and to proactively replace its aging infrastructure based on risk prioritization.

LESSONS LEARNED AND RISK TRENDS

In prior WMPs, Liberty analyzed and assessed all forced outage data as having an equal likelihood of causing an ignition. Evaluating risk events equally is not a meaningful approach unless it relates to other risk drivers. Liberty's new approach to assessing overall likelihood that a wildfire will ignite from Liberty's overhead assets is to assess the likelihood that the line will experience a fault, and that the resulting fault will ignite fuel beds under lines. Liberty's planned 2022-2023 wildfire mitigation initiatives were identified, analyzed, and assessed based on the following:

- Fault prevention: includes grid hardening, asset management and inspection, and vegetation management work to reduce likelihood of an outage.
- Ignition prevention: includes investing in emerging technologies to detect and neutralize potentially hazardous line to ground faults, such as HIFD, Ground Fault Neutralizer ("GFN"), or Rapid Earth Fault Current Limiting ("REFCL") that are needed to reduce the likelihood of wildfire ignition in the case that a fault or failure does occur. Another way to reduce ignition risk is to de-energize lines during extreme high wind events.
- Fire response and impact mitigation includes emergency preparedness plans, situational awareness efforts to monitor high risk weather days, and adjusting operations and construction activities based on elevated fire risk days to minimize the effects of a fire.

Figure 4.3- 1: WMP initiative assessment



- Risk event: Analysis of historic fault types is the first step in assessing the likelihood of wildfire risk events. Risk events pertinent to Liberty's historic outages are analyzed and discussed below. Fault reduction can be measured at the circuit/span level annually to demonstrate mitigation effectiveness over time and reflects a shift to supporting continued mitigation efforts through quantitative analysis and to pilot program results before expanding system-wide. As a smaller utility, only prudent investments with demonstrated wildfire risk reductions will be pursued or continued. Liberty conducts annual wildfire studies of baseline risk assessments at the circuit level.

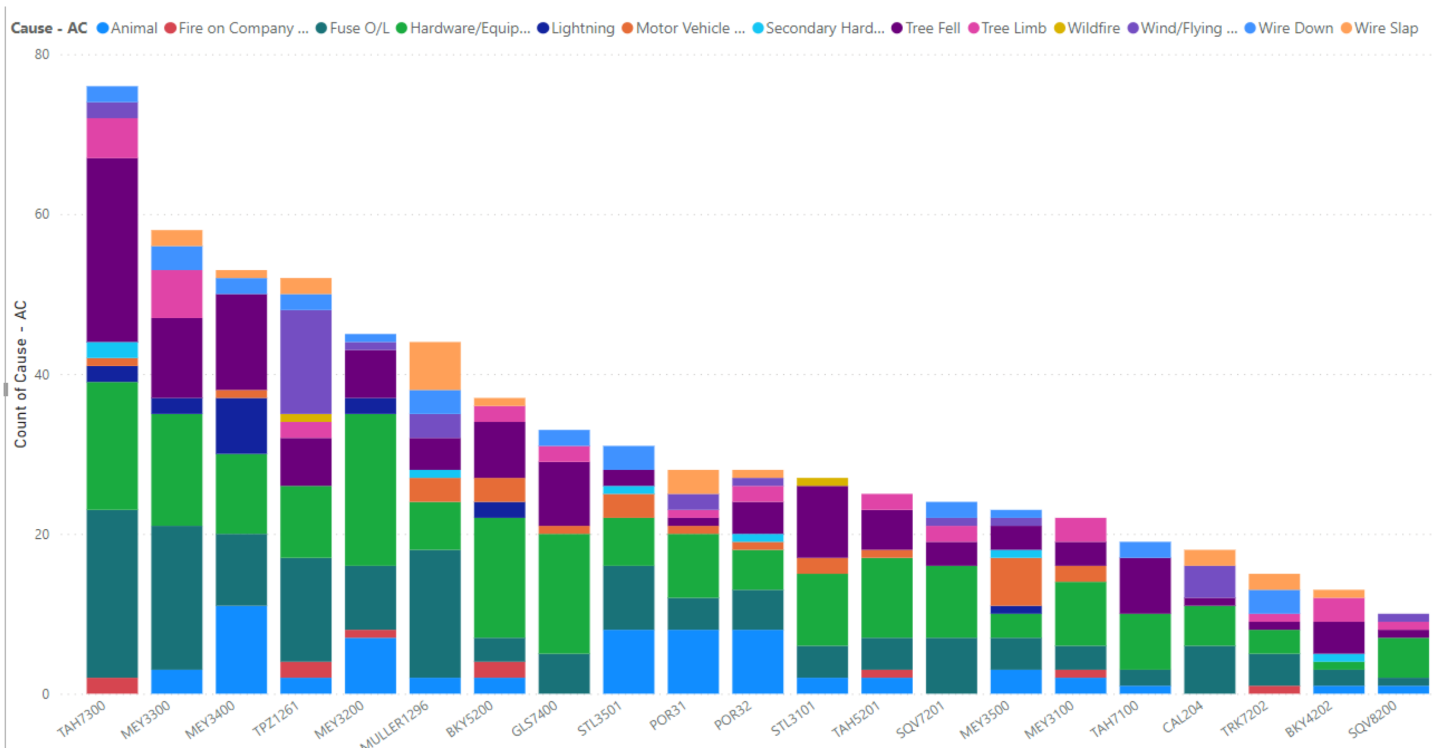
Risk Data and Analysis:

Liberty analyzed all forced outage data and adjusted data entries to reflect only major wildfire risk drivers to be included in the analysis. Wildfire risk events include the following:

- Wire down
- Wire slap
- Weather event – lightning, wind, fire
- Equipment and fuse failure

Over the last four years, Liberty has experienced over 1,270 forced outage events. Events with no wildfire risk potential were excluded from the risk study. Excluded events include switching, operations errors, snow unloading, loss of source, feeder overload, and construction-related outages. Of the remaining 822 risk events, each outage was categorized into 16 potential fire risk types and the historic totals are summarized below by circuit.

Figure 4.3- 2: Liberty Historic Outages by Risk Type



By analyzing the outage history by type and circuit location, Liberty can better assess the needs for each location and the specific mitigations that would best prevent outages.

Hardware/Equipment Failure:

Liberty's aging overhead system has experienced many forced outages over the last four years and is a major risk event Liberty analyzed. Based on the historic count of this risk driver of 246, or 31% of the forced outages included in the wildfire risk study are from failing assets in-service. Fuse failures, or blown fuses, is an indicator of an outage. Once Liberty personnel is dispatched to the outage location, the field worker will either detail the reason for the outage (*i.e.*, vegetation contact) or merely document that the fuse is blown for undetermined reasons. Liberty still has expulsive fuses on its system and because of this each "fuse failure" is assumed to emit a spark and is considered a high-risk event.

As discussed in Section 7.3.3.7, Liberty replaced 867 expulsive fuses with non-expulsive fuses in 2021 and plans to replace 1,500 fuses per year over the next 6 years. See Table 4.3- 1 below for current risk events.

Table 4.3- 1: Outage Types

Type of Outage	Outages (2017-2021)
Hardware/Equipment Failure	206
Insulation Failure	6
Deterioration	40
Fuse Failure	160
Total	**412**

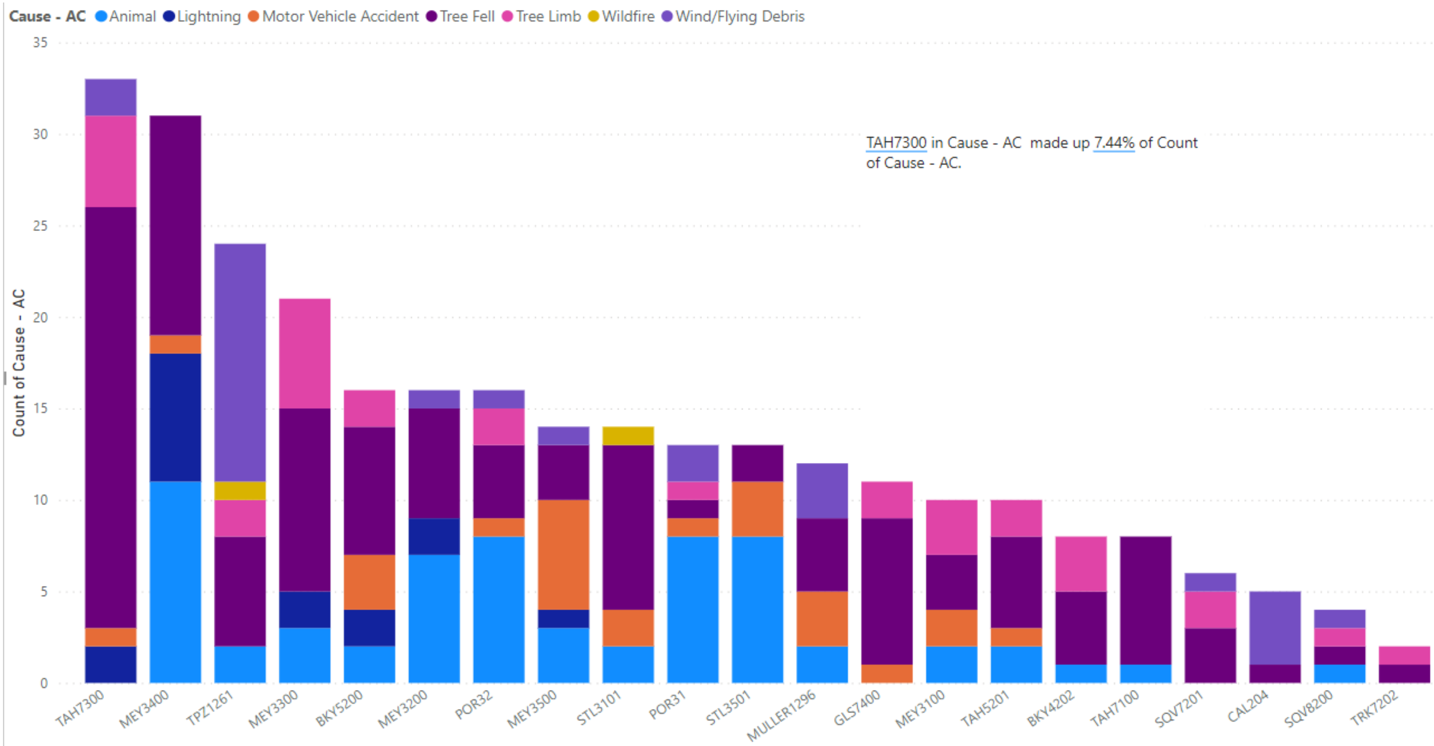
Prior to the WMP, Liberty did not have a formal asset replacement program based on asset age, condition, or engineering studies and instead inspected and remediated overhead assets every five years. This run-to-failure model leads to system failures, customer outages, and most importantly fire risk events. Liberty completed a system-wide survey in 2020-2021 that documented GIS location, condition of poles, all hardware and equipment of poles, and detailed condition codes from the G.O. 165 inspection level findings. Based on G.O. 95 remediation timelines, safety-related infractions for Level 1 findings for pole replacements and repairs were completed within 3 months and Level 2 pole replacements and repairs were completed in HFTD Tier 3 first with the remaining work planned for this year. Liberty's plan for addressing the remaining Level 3 poles is discussed in Section 7.3.4.9.

The system survey provided the baseline for Liberty's asset failure risk analysis. Performance can be measured each year to show the number of asset repairs and replacements by circuit as detailed in the pole risk assessment section. In addition, the number of risk events, or outages per circuit caused by Hardware/Equipment failure or fuse failure, could also show performance and risk reduction for each risk study period.

Outages caused by outside forces:

Liberty also analyzed major outside forces that historically have caused outages. These factors include animal contact, lightning, car hit pole, vegetation contact, and wind-related outage events. See Figure 4.3- 3 below.

Figure 4.3- 3: Outages Caused by Outside Forces



Next, Liberty assessed reasons related to the outage type and noted the following:

- Lightning-related outages are more likely to occur in May and July in areas that are also in high wildfire risk areas on the Meyers circuits. Liberty's wildfire mitigations for this area could include enhanced vegetation clearing for fall in trees with strike potential or enhanced situational awareness and emergency response monitoring thunderstorm activities.
- Tree Fell, Tree Limb, and Wind/Flying Debris related outages were the largest outage event types in this category and enhanced vegetation management mitigations are key to reducing this outage type going forward. See Section 7.3.5 for Liberty's vegetation mitigation plans. Liberty also noted that this risk type was more likely to occur in the winter months of December through February from heavy snowfall and may need further analysis on the frequency of this outage type and significant weather events for determining wildfire risk trends.

Pole Risk Assessment:

1. **Purpose**: Survey Liberty's poles to assess and gather data to determine the risk and appropriate precautions needed to ensure poles are in good condition and don't pose a risk to Liberty's systems.
2. **Relevant Terms**: Priority levels are the designated G.O. 165 inspection level findings. Pole conditions relate to the inspection condition codes identified on each pole and include an evaluation of all hardware on the pole. Intrusive pole inspections are detailed testing of older poles in Liberty's service territory that are tested once every 10 years.

3. **Data Elements**:

Data Source	Data	Spatial Input	Reporting Frequency
2020 Pole Survey Data	Pole Conditions, priority levels	Latitude/Longitude GIS coordinates	Active Database
Intrusive Inspections	Intrusive Pole Conditions	Latitude/Longitude GIS coordinates	Annual

4. **Data:** The 2020 Pole Survey data was an effort Liberty undertook to inventory the condition of its poles. Condition codes were noted as well as priority determination. During the Pole Risk Analysis, poles with structural issues were identified and assessed. Poles with condition codes cracked pole, pole top spilt and pole rot were assigned a "pole issue" identifier. Similarly, poles with condition codes crossarm broken, loose, cracked were assigned a "crossarm issue" identifier. Liberty also assigned a Pole Risk of Failure of low, medium, and high using the pole and crossarm issue identifier and other condition code categories. For example, a level 3 priority pole with a missing High Voltage sign would be categorized as low pole risk of failure in the Pole Risk Analysis. While this condition does need to be remediated within 5 years, it typically will not result in a pole falling in-service, thus has a low risk of failure. However, if a level 3 pole has a condition code of cracked pole, the risk of failure is moderate due to the potential structural integrity and will need to be inspected more frequent.

   Liberty's fire assessment of high-risk poles included all poles that had structural integrity issues noted in the condition codes of "Pole Needs Replacing" and/or "Crossarms Need Replacing Broken/Cracked" and did not factor in level finding.

   Liberty's intrusive inspection data is a survey done on poles every ten years. In 2020 and 2021, Liberty performed 4,747 intrusive pole inspections. To the extent any of the system survey poles noted "pole needs replacing" and the pole also had an intrusive pole inspection in the last 3 years, the pole was downgraded to "moderate risk" and not high risk.

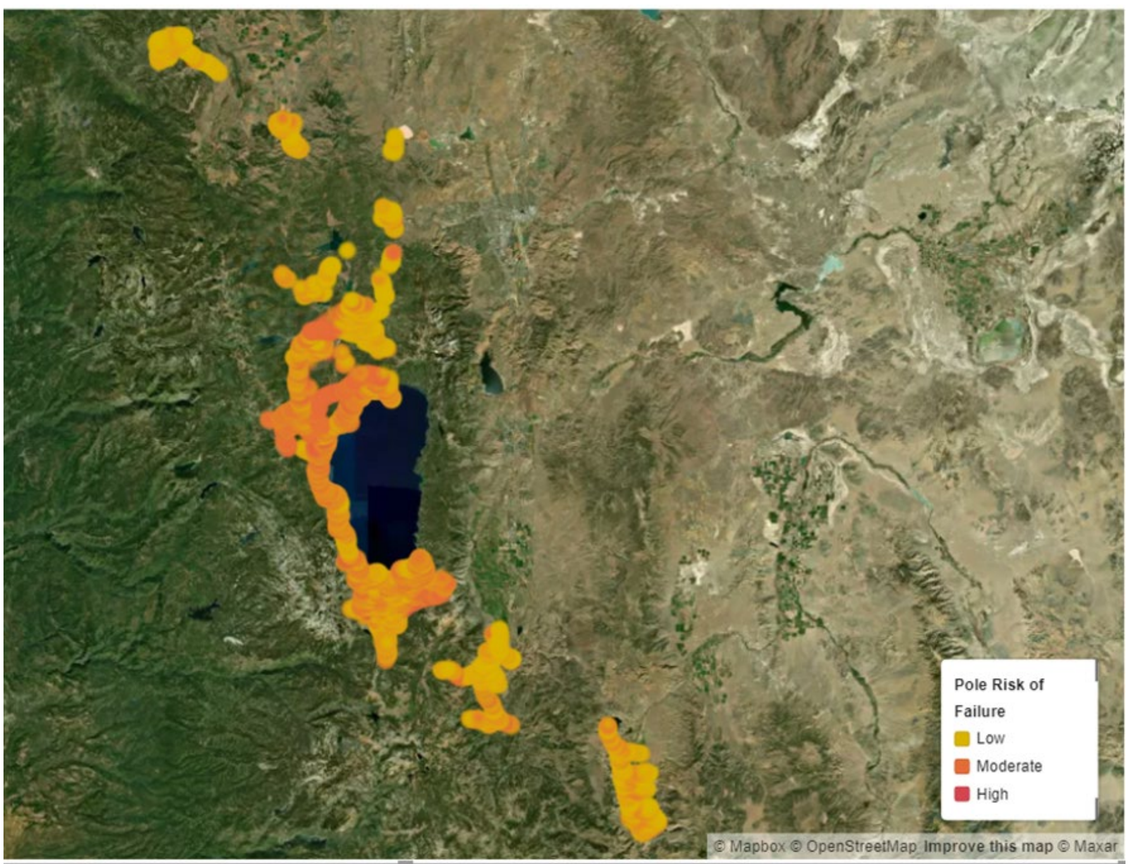
Figure 4.3- 4: Intrusive Pole Inspections in 2020 and 2021

Intrusive Pole Inspections in 2020 and 2021

Circuit	Number of Poles	Count of Intrusive Inspection	Average Pole Age (Years)
629	146	14	27
650	64	38	22
BKY4201	141	103	37
BKY4202	500	255	43
BKY5100	86	2	46
BKY5200	1154	1031	41
HOB7700	235	153	46
RUS7900	108	25	32
SQV7201	364	95	42
TAH5201	965	874	44
TAH7200	84	51	35
TAH7300	2577	2104	42
Total	**6424**	**4745**	**42**

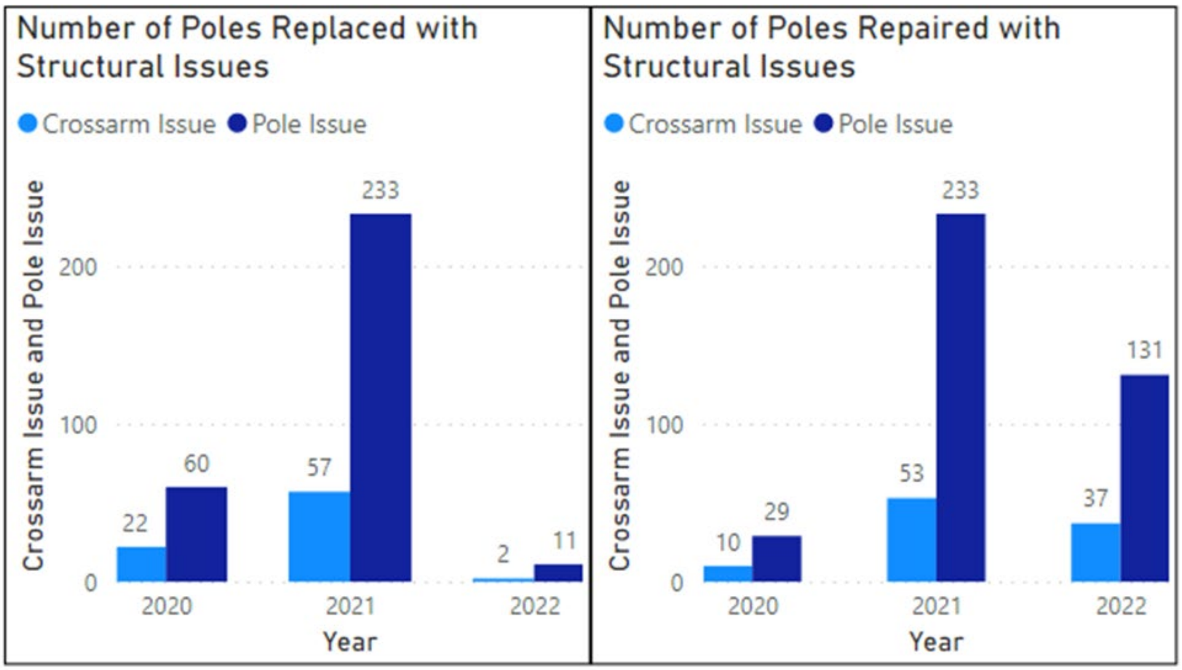
5. **Analysis**: As discussed above, poles were assessed and risk was categorized for each pole into high, moderate, and low risk. The map below (Figure 4.3- 5) identifies each pole in our system and its risk of failure.

Figure 4.3- 5: Pole Risk of Failure



Determining the pole risk of failure used three factors: priority levels, condition codes, and structural conditions. The structural conditions are a key indicator of determining a pole's risk and the remediation work of which helps to mitigate the risk of failure. Liberty has experienced a high number of assets failing in service and causing outages. Expediting pole replacements and asset repairs since the system survey has mitigated the likelihood of outages. Liberty measures this performance as asset risk reduction by circuit. Below, the two charts summarize the mitigation efforts taken to replace and repair poles with structural issues.

Figure 4.3- 6: Number of Poles Replaced



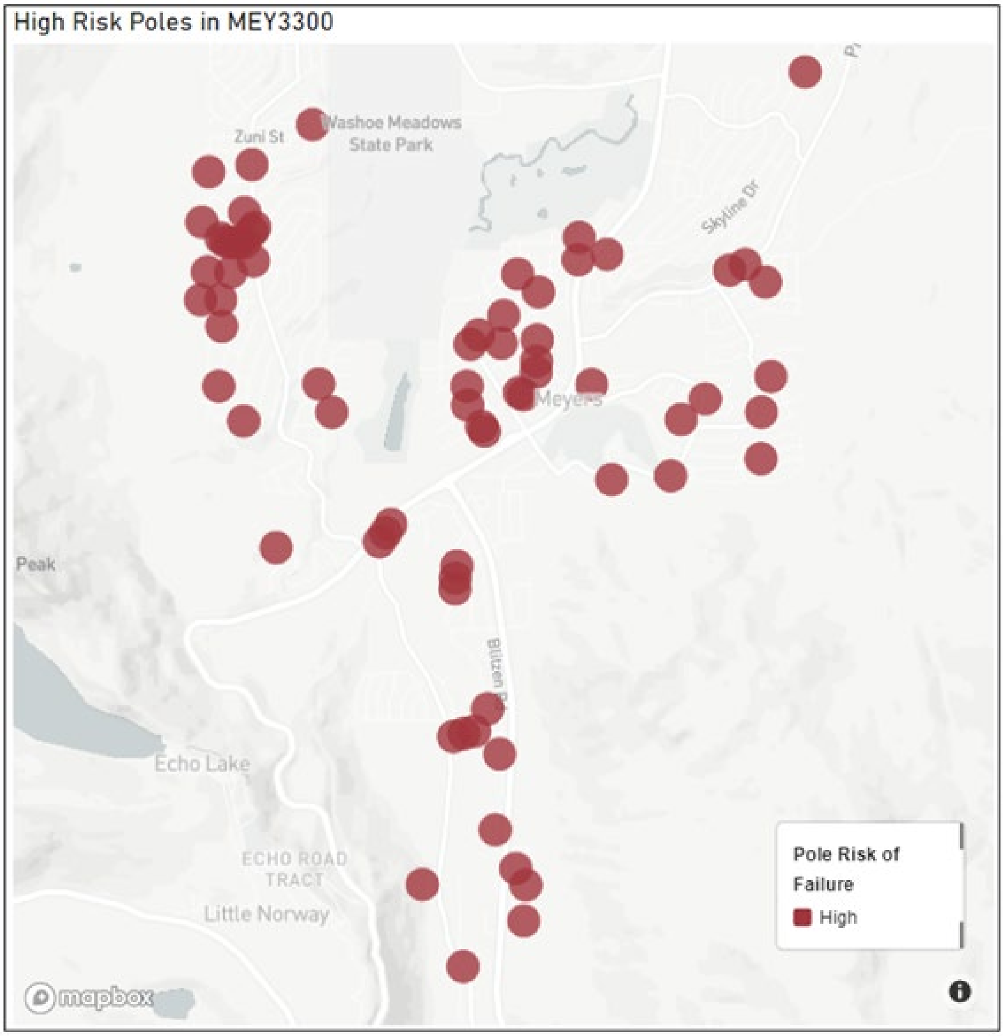
Most of Liberty's poles qualified as a low risk. There were 1,125 poles that were classified as a high risk after their initial survey. Of those poles that qualified as high risk, 240 were repaired and 271 were replaced.

Figure 4.3- 7: Pole Risk of Failure

Pole Risk of Failure	Total Poles	Repaired Poles	Replaced Poles
High	1125	240	271
Low	13227	784	204
Moderate	8647	207	57
Total	**22999**	**1231**	**532**

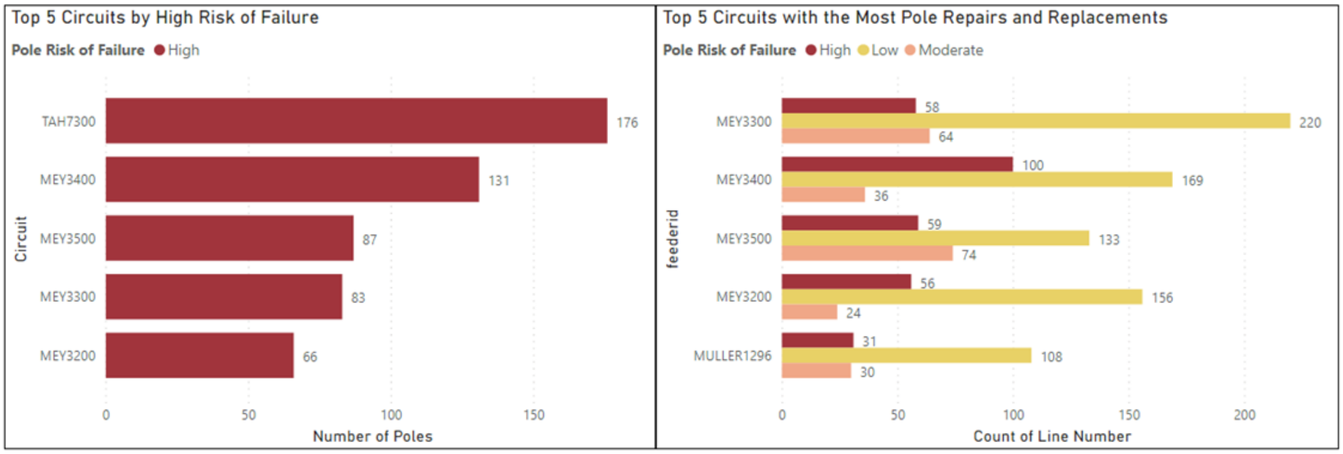
Using a combination of all these factors helps highlight which circuits have the most at-risk poles. A pole with a high risk of failure is prioritized to be repaired or replaced in a timely matter to mitigate an ignition event. For example, the MEY3300 circuit is one of the highest Reax fire risk circuits.

Figure 4.3- 8: Meyers 3300 Circuit Pole Risk Map



At the time of the initial inspection survey, the MEY3300 circuit had the third most poles with a high risk of failure. At the time of the risk analysis, the MEY3300 circuit had the most pole repairs and replacements on the whole system. The graphs below show the top five circuits with the highest number of high pole risk failures and the top five circuits with the most pole repairs and replacements:

Figure 4.3- 9: Top Five Circuits by High Risk of Failure and by Highest Amount of Pole Replacements



<u>**Tree Risk Assessment**</u>:

1. **Purpose**: Survey trees in Liberty's service territory and collect data to determine the characteristics of trees relevant to the risk they pose to Liberty's systems, such as tree condition and position. Compare these findings to other risk metrics to better inform risk-based decision-making and initiative prioritization.
2. **Data**: Liberty first assessed the 2021 LiDAR tree dataset to take inventory of trees in its service territory, including key characteristics such as tree coordinates, distance of nearest structure from the tree, and the circuit the structure is on. Condition codes can also be found in this dataset, indicating whether the tree has been prioritized for inspection to determine whether a work order is needed. A tree may have condition codes for the relevant risk of either fall-in or grow-in to the nearest wire. For example, trees with a fall-in priority of 2 or greater would overstrike conductor by up to 6 feet and would be prioritized for work accordingly. Liberty then considered the Reax wildfire risk ratings associated with circuit spans nearest to the tree. By comparing a tree's condition to its positioning near areas of high or very high wildfire risk, Liberty identified locations of the riskiest trees in its service territory and prioritized work to address the highest tree risk.
3. **Analysis**: Liberty's LiDAR tree data is a survey done annually on trees in its service territory. 2021 results captured relevant information on 253,894 treetop data, as opposed to 27,164 trees in 2020, or the 699,030 total trees inventoried in a 300 foot corridor on either side of Liberty's lines.[7] The following tables summarize how many trees have been prioritized for work due to either having most of the tree grown within 6 feet of a structure (Grow-In) or due to the tree potentially striking the conductor:

[7] Prior to LiDAR inspections, Vegetation Management annual inspections were documented in Liberty's Vegetation Management Inventory System ("VMIS") to include visual inspection details of tree, circuit #, tree probability of failure, and the needed work performed (*i.e.*, pruning or removal).

Figure 4.3- 10: Grow-in Trees

Grow-In Code	Number of Trees	Average Distance to Wire	Average Distance to Nearest Structure
GI_ZONE_1	127	0.76	55.04
GI_ZONE_2	1617	3.08	48.38
GI_ZONE_3	5488	5.19	49.79
GI_ZONE_4	44323	9.08	53.59
Total	**51555**	**8.45**	**53.02**

Trees indicated as "GI_ZONE_3" to "GI_ZONE_1" have been prioritized for work because of their proximity to a nearby wire of six feet or less. The table above shows that 7,232 trees in Liberty's service territory have been labelled for review to determine whether work will be needed to keep said trees within compliance standards and mitigate ignition risk from tree contact due to proximity. The graph below shows a breakdown of these trees by circuit. Circuits within South Lake Tahoe and on Lake Tahoe's west shoreline contain the highest frequency of higher priority Grow-in trees.

Figure 4.3- 11: Grow-in Trees by Circuit

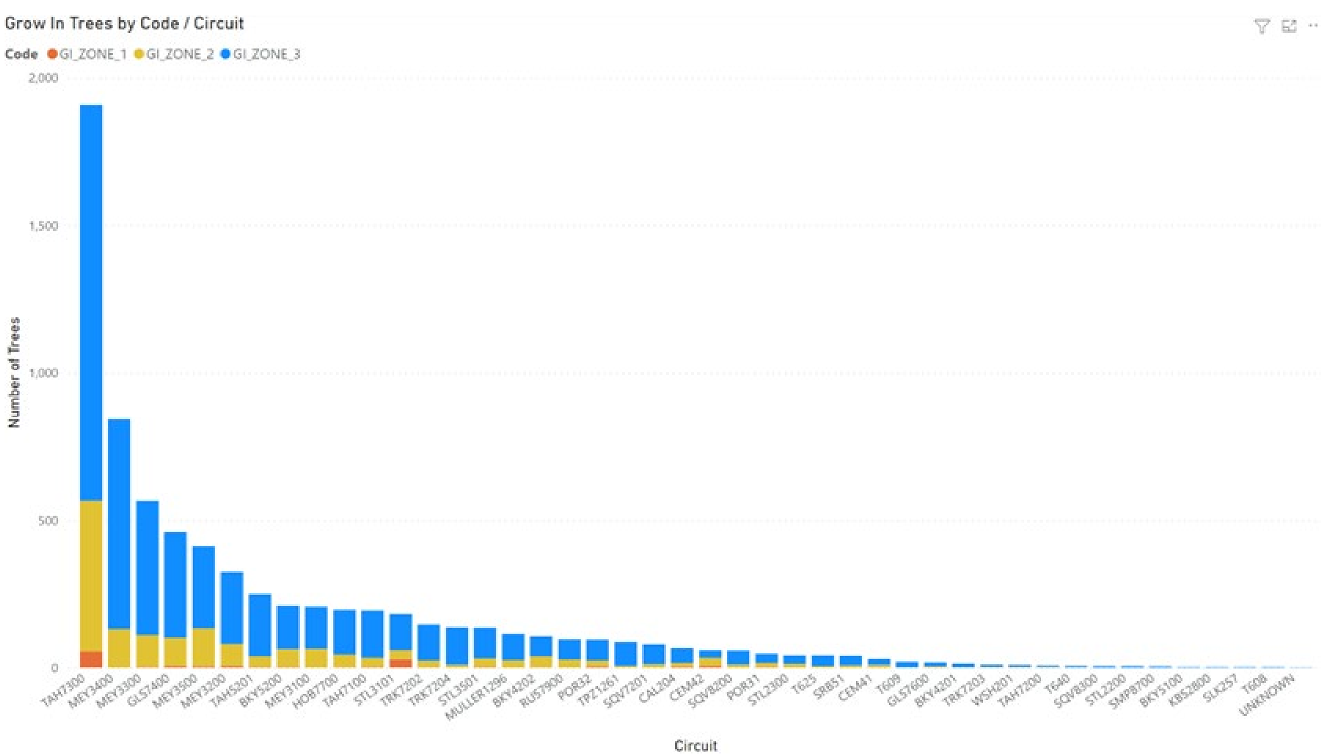
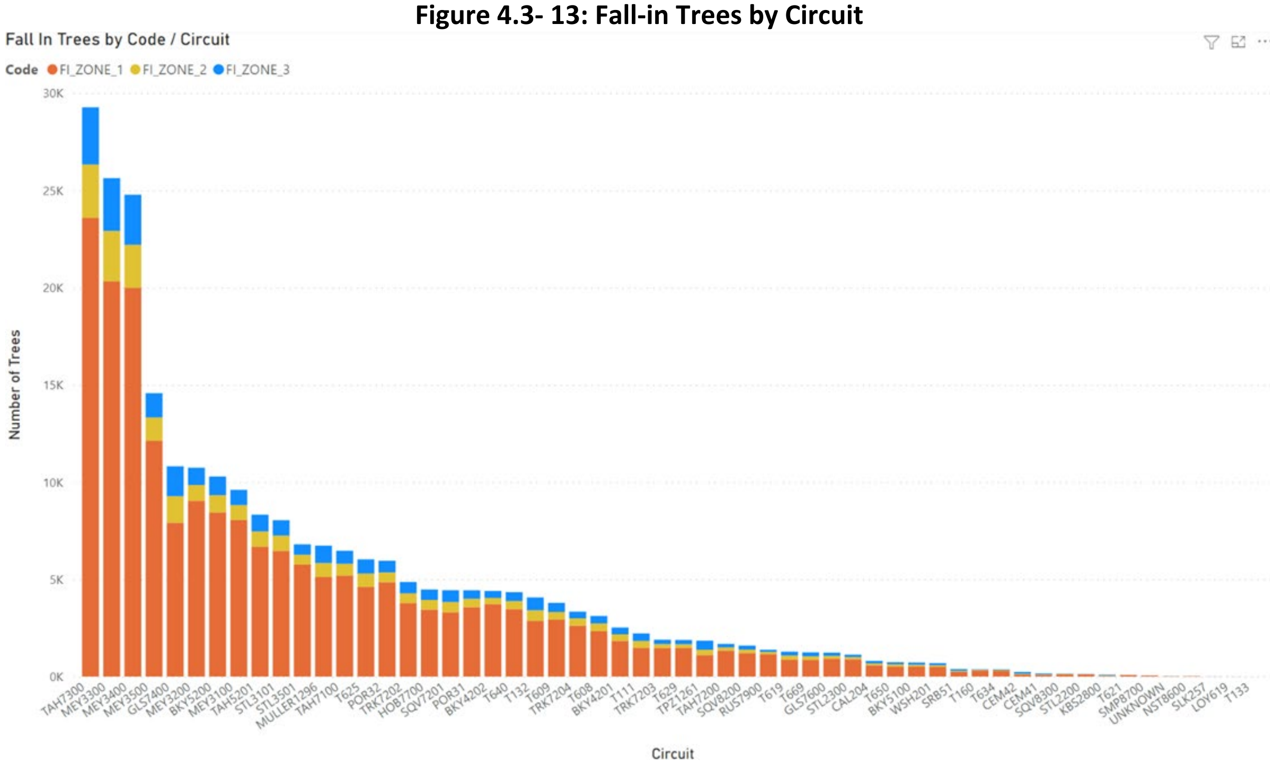


Figure 4.3- 12: Fall-in Trees

Fall-In Code	Number of Trees	Average Distance to Wire	Average Distance to Nearest Structure
FI_ZONE_1	198213	37.33	74.03
FI_ZONE_2	24774	67.22	90.76
FI_ZONE_3	27226	72.23	91.80
Total	**250213**	**44.08**	**77.62**

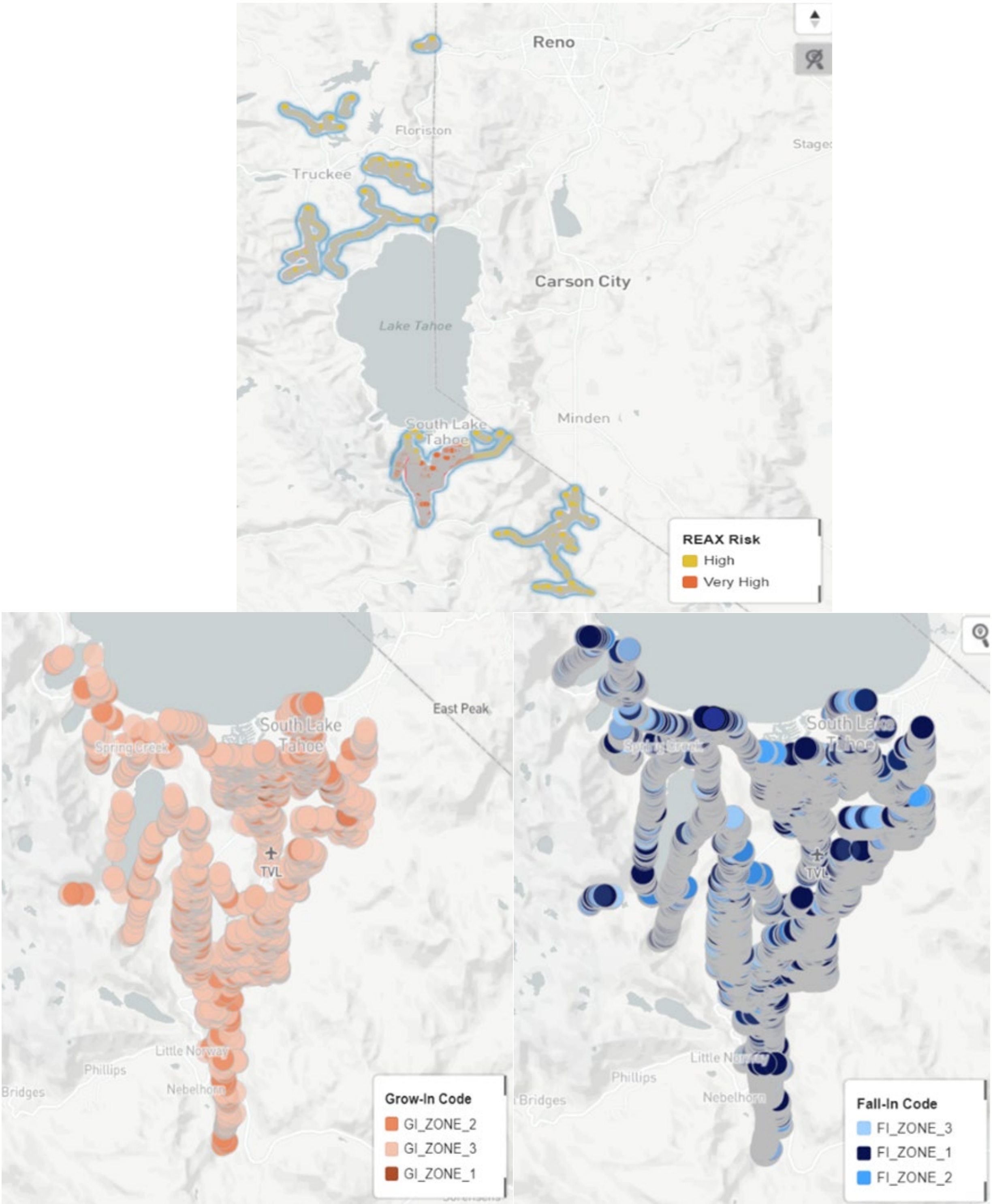
Trees indicated as “FI_ZONE_3” to “FI_ZONE_1” have been scheduled for inspection because of their potential to fall and strike wire. Liberty uses fall-In condition codes to prioritize inspections and categorize this risk. The table above shows that most trees in Liberty’s service territory have been prioritized for fall-in review because they either strike within six feet of conductor, or in many cases, overstrike conductor if they fall. The graph below shows a breakdown of these trees by circuit. Trees that have been prioritized for maintenance to prevent fall-in are concentrated similarly to the grow-in trees, with the highest number of these located in South Lake Tahoe and on Lake Tahoe’s West shoreline.

Figure 4.3- 13: Fall-in Trees by Circuit



<u>Tree risk as a function of wildfire risk</u>: Liberty identified the areas of greatest tree risk by cross referencing the highest concentrations of trees that have been flagged for either grow-in or fall-in related maintenance with circuit spans in Liberty’s service territory that have been identified by Reax as having a “High” or “Very High” wildfire risk, as described in Section 4.2.1. Infrastructure with high or very high wildfire risk is shown on the first map (top, center) below. While there are circuit spans at high risk in both North and South Lake Tahoe, all infrastructure at very high wildfire risk is concentrated in South Lake Tahoe. The second map (bottom, left) shows the concentration of 2,351 trees in the MEYERS-3100, 3200, 3300, 3400, and 3500 circuits that have been prioritized for work related to grow-in. The third map (bottom, right) shows the same breakdown for fall-in trees.

Figure 4.3- 14: Tree Risk Map



As the figures above indicate, most trees identified near Liberty infrastructure have been prioritized for fall-in review and may also have been prioritized for grow-in related work. This is due in part to the nature of the vegetation and terrain in Liberty's service territory. Therefore, layering these codes with Reax wildfire risk allows Liberty to identify which trees have been prioritized for maintenance to remain in compliance and are also near circuits with the highest wildfire risk. The MEYERS-3300 circuit contains almost all infrastructure with a very high wildfire risk rating, as well as a high concentration of trees scheduled for review, therefore making it the circuit with the highest overall tree risk. See Table 4.3- 2 below shows the number of fall-in trees where the tree overstrikes conductor by over 6 feet (Zone 1).

Table 4.3- 2: Number of Zone 1 Fall-in Trees by Circuit

Circuit	Number of FI_ZONE_1 Trees
TAH7300	23,582
MEY3300	20,324
MEY3400	19,991
MEY3500	12,119
MEY3200	9,029
TOTAL	**85,045**

Future performance metrics: The initial LiDAR survey in 2020 for South Lake Tahoe can be compared with the full system LiDAR survey performed in 2021. With the tree remediation work performed in South Lake Tahoe, improvements are shown in 2021 in the same area with reductions in clearance zones for both categories. Section 7.3.5.7 describes the LiDAR analytical capabilities in detail.

Table 4.3- 3: VM Clearance Zones

Clearance Zone	2020	2021	Change
Within maintenance clearance zone	966	655	-311
Approaching maintenance clearance zone	23,130	21,198	-1,932

Circuit Risk Assessment:

Liberty assessed tree and pole risk factors using the wildfire risk designated areas as the basis for determining the appropriate risk metrics to quantify. From this baseline assessment, mitigations will be measured each year. As shown in the figure below, of the 701 total overhead line miles in Liberty service territory, 163 miles are in high wildfire areas and 104 miles are in high wildfire risk areas, or 38% of the lines. Liberty uses risk mapping of these heightened risk areas to evaluate the appropriate groups of mitigations tailored to the location specific weather patterns, outage events, ignition events, recent grid hardening, and enhanced vegetation management to plan annual work needs. Measuring wildfire risk reductions with mitigations is varying project/program implementation phases is a challenge and calls for a dynamic modeling approach.

Figure 4.3- 15: Overhead Line Miles by Wildfire Risk Rating

Below is a summary of tree risk analysis conducted by circuit and the results:

Figure 4.3-16 Figure 4.3- 16: Tree Risk by Circuit

Circuit	grow_in_exposure	fall_in_exposure	Exposure_Score	Exposure_Rank
MEY3500	High	High	1	Very High
MEY3300	High	Moderate	0.851190476	Very High
MEY3200	High	Moderate	0.803571429	Very High
MEY3100	Moderate	High	0.696428571	High
MEY3400	High	Moderate	0.642857143	High
STL3101	Moderate	High	0.541666667	High
STL2300	High	Low	0.464285714	Moderate
STL2200	Moderate	Low	0.416666667	Moderate
STL3501	Moderate	Moderate	0.333333333	Moderate
T640	Low	High	0.285714286	Moderate
T111	Low	Moderate	0.178571429	Low
MULLER1296	Low	Low	0.095238095	Low
TPZ1261	Low	Low	0.071428571	Low

Liberty uses the summary results from its quantitative pole and tree risk analysis to qualitatively assess findings by circuit. See Table 4.3- 4 below for the summary results for the Meyers 3400 circuit.

Table 4.3- 4: Meyers 3400 Circuit Risk Assessment

Meyers 3400	**Risk Exposure**	**Tree Risk - Circuit Rating**	**Pole Risk - Circuit Rating**
Total Overhead Lines – Risk Exposure	54.4 miles	High	Moderate
Very High Wildfire Risk	18.1 miles		
High Wildfire Risk	5.3 miles		
Moderate Wildfire Risk	17.3 miles		
Low Wildfire Risk	13.6 miles		

Liberty's risk methodology helps to pinpoint which trees, poles, and areas in each circuit that pose the highest risk. The overall tree risk rating for Meyers 3400 was assessed as high due to the 19,991 trees that are in Fall-in Zone1 and have a six-foot overstrike potential. Enhanced vegetation inspections targeting the areas of the high wildfire risk areas for the Fall-in zones is priority for this circuit. Current asset risk reduction mitigations for this circuit include:

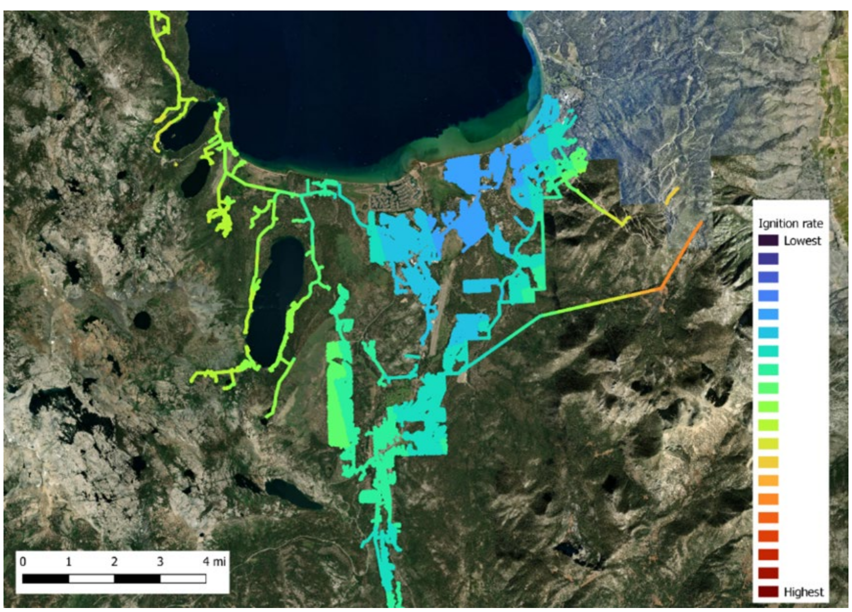
- Covered Conductor completed and planned projects includes 8 miles of overhead lines, or 14.5% of the total circuit miles, and includes 231 pole replacements, or 11.7% of poles.
- Repairs and pole replacements from the system survey adds new infrastructure to Liberty's aging system. Since 2020, Liberty has replaced an additional 110 poles, or 5.9% of total poles and repaired 195 poles, or 10.5% of poles.
- Identifying risky poles and their condition is one of the preventative functions. Of the 131 high risk poles identified, 76.3% have been remediated since 2020.

Figure 4.3- 17: Remediated Poles by Risk of Failure Rating

Pole Risk of Failure	Total Poles	Repaired Poles	Replaced Poles
High	131	41	59
Low	1049	130	39
Moderate	682	24	12
Total	**1862**	**195**	**110**

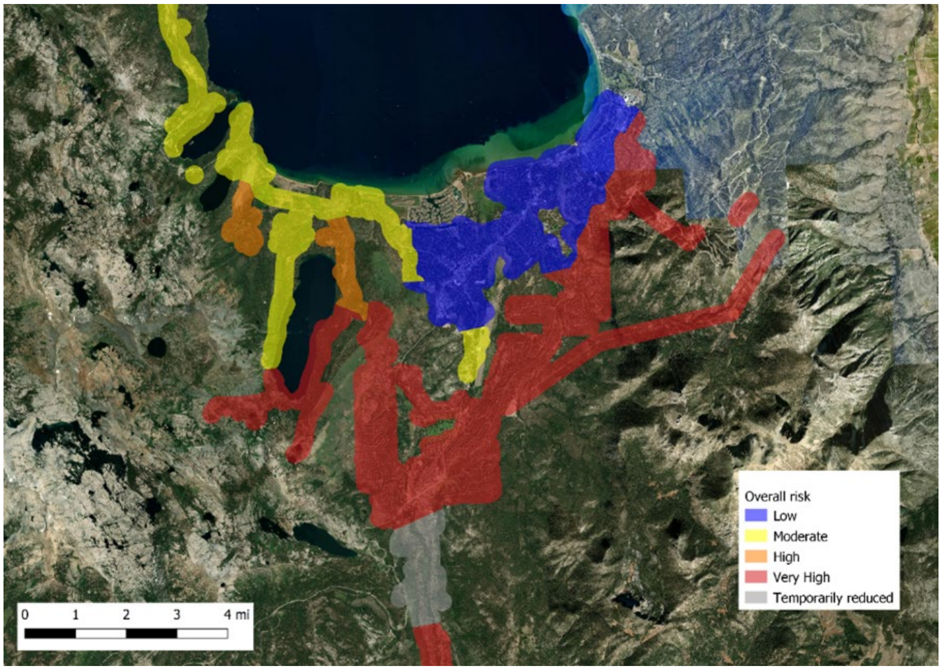
As discussed in Section 4.5.1.1, Reax evaluated ignition rates in Liberty's service territory that will incorporated in future circuit risk assessments. Ignition rates in the yellow and orange circuit segments can indicate an elevated PSPS or wildfire risk and could have enhanced situational awareness mitigations or sectionalizing equipment installed to segment lines.

Figure 4.3- 18: Ignition Rates by Circuit



In addition, the updated fire risk model resulted in changes to Liberty's fire risk ratings described in Section 4.2.1. More areas in the Fallen Leaf region are now very high fire risk areas from the original moderate/high rating. It should be noted that Liberty already had two covered conductor projects planned for Fallen Leaf that includes replacing 2.19 miles of overhead lines and replacing 76 poles. Another temporary risk reduction in South Lake Tahoe is to factor in the burn scar area damaged by the area fires last year.

Figure 4.3- 19: Fallen Leaf Region Risk Profile



4.4. Research proposals and findings

Report all utility-sponsored research proposals, findings from ongoing studies and findings from studies completed in 2020 and 2021 relevant to wildfire and Public Safety Power Shutoff (PSPS) mitigations.

4.4.1. Research proposals

***Instructions**: Report proposals for future utility-sponsored studies relevant to wildfire and PSPS mitigation. Organize proposals under the following structure:*

1. ***Purpose of research** – brief summary of context and goals of research*
2. ***Relevant terms** - Definitions of relevant terms (e.g., defining "enhanced vegetation management" for research on enhanced vegetation management)*
3. ***Data elements** - Details of data elements used for analysis, including scope and granularity of data in time and location (i.e., date range, reporting frequency and spatial granularity for each data element, see example table below)*
4. ***Methodology** - Methodology for analysis, including list of analyses to perform; section must include statistical models, equations, etc. behind analyses*
5. ***Timeline** - Project timeline and reporting frequency to the Office of Energy Infrastructure Safety*

Distribution Fault Anticipation ("DFA") - Liberty plans to participate in a collaborative research project with Texas A&M to evaluate DFA.

1. ***Purpose of research*** – DFA is a technology developed by Texas A&M to analyze high-fidelity current waveforms with algorithms to anticipate the type and location of common electrical distribution failures. DFA hardware installed in Liberty's service territory aims to increase the accuracy of the technology by providing additional data to the algorithms that are used to identify distribution asset failures. The deployment of DFA technology will help to anticipate potential distribution failures and reduce ignition potential in Liberty's service territory.
2. ***Relevant terms*** – DFA – high fidelity metering is sent back to servers that output reports to aid in anticipating faults.
3. ***Data elements*** – Instantaneous current and voltage readings. Reports with recommendations are sent when the events are triggered automatically.
4. ***Methodology*** – Output reports from DFA software are algorithmically put together and provide recommendations for field to investigate.
5. ***Timeline*** – DFA hardware will be installed by the end of 2022 and will be evaluated throughout 2023.

High Impedance Fault Detection ("HIFD")

1. ***Purpose of research*** – Liberty is planning to collaborate with the University of Nevada, Reno to investigate the ability of HIFD to mitigate ignition potential during high impedance faults. The research will determine the ability of the HIFD capable relays to detect high impedance faults and determine if the faults would have been detected using traditional overcurrent methods. The research also hopes to determine if HIFD can clear faults fast enough to reduce ignition potential.
2. ***Relevant terms*** – HIFD is designed to detect faults that cannot normally be detected by standard relays and protection schemes. An example of this is when a tree takes a line to ground, the ground acts as a high impedance path to ground, producing small short circuit current, which means that no relay would operate. HIFD adds sensitivity to these situations to increase chances of detecting a high impedance fault and isolating that circuit.
3. ***Data elements*** – For selected lines, Liberty will evaluate how much quicker high impedance faults are detected. Without this project, high impedance faults would only be found once the fault turn into a lower impedance fault. Every high impedance fault found with this technology would be a positive outcome.
4. ***Methodology*** – Install the HIFD settings produced by University of Nevada Reno into the protection relays feeding Liberty's piloted lines. First, Liberty will set these to alarm on a high impendence fault and inspect to see if they are working properly. Liberty will evaluate the results to determine how to proceed.
5. ***Timeline*** – After delays in the project timeline, HIFD is set to be deployed in 2022.

4.4.2. Research findings

Instructions*: Report findings from ongoing and completed studies relevant to wildfire and PSPS mitigation. Organize findings reports under the following structure:*

1. ***Purpose of research*** *- Brief summary of context and goals of research*
2. ***Relevant terms*** *- Definitions of relevant terms (e.g., defining "enhanced vegetation management" for research on enhanced vegetation management)*
3. ***Data elements*** *- Details of data elements used for analysis, including scope and granularity of data in time and location (i.e., date range, reporting frequency and spatial granularity for each data element, see example table above)*
4. ***Methodology*** *- Methodology for analysis, including list of analyses to perform; section must include statistical models, equations, etc. behind analyses*

5. ***Timeline*** *- Project timeline and reporting frequency to the Office of Energy Infrastructure Safety. Include any changes to timeline since last update*
6. ***Results and discussion*** *– Findings and discussion based on findings, highlighting new results and changes to conclusions since last update*
7. ***Follow-up planned*** *– Follow up research or action planned as a result of the research*

Outage Rate Study ("ORS"):

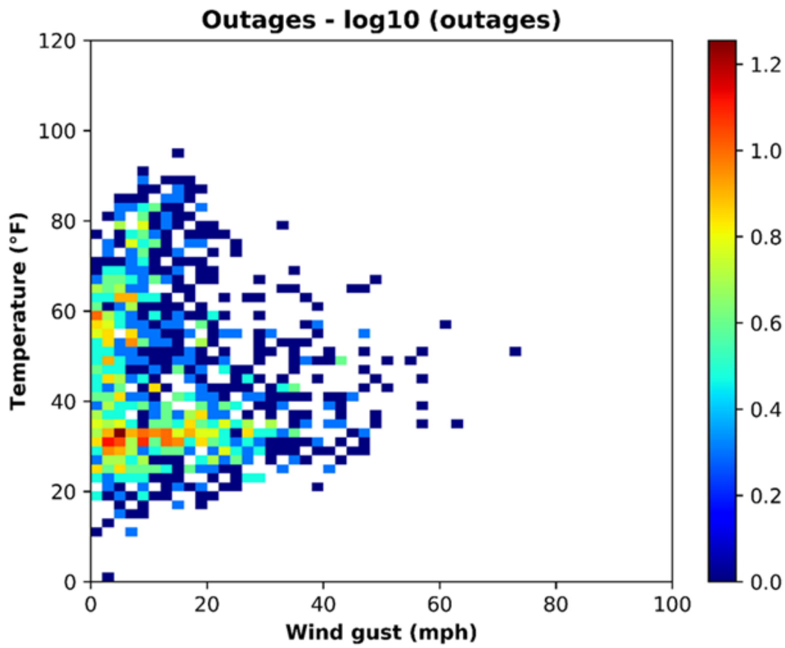
1. ***Purpose of research*** – Calculate outage rates using Liberty's forced outage data to determine appropriate ignition probability inputs by analyzing historic weather trends with the historic outage event time and date inputs.
2. ***Relevant terms*** – *Real Time Mesoscale Analysis ("RTMA")* is a dataset for high-spatial and temporal resolution analysis for near-surface weather conditions. This dataset includes hourly analyses at 2.5 km for continental U.S. *Outage rate* is the outages per line mile and hour.
3. ***Data elements*** -

Data	Data Source	Spatial Input	Reporting Frequency
Historic Forced Outages	Liberty's Outage Management System ("OMS")	Latitude/Longitude GIS coordinates	Active Database; data is analyzed annually for the risk model inputs
Historic Weather Data	RTMA data	Latitude/Longitude GIS coordinates	
Liberty's Overhead Lines	Liberty's GIS	Latitude/Longitude GIS coordinates	Active Database

4. ***Methodology*** –

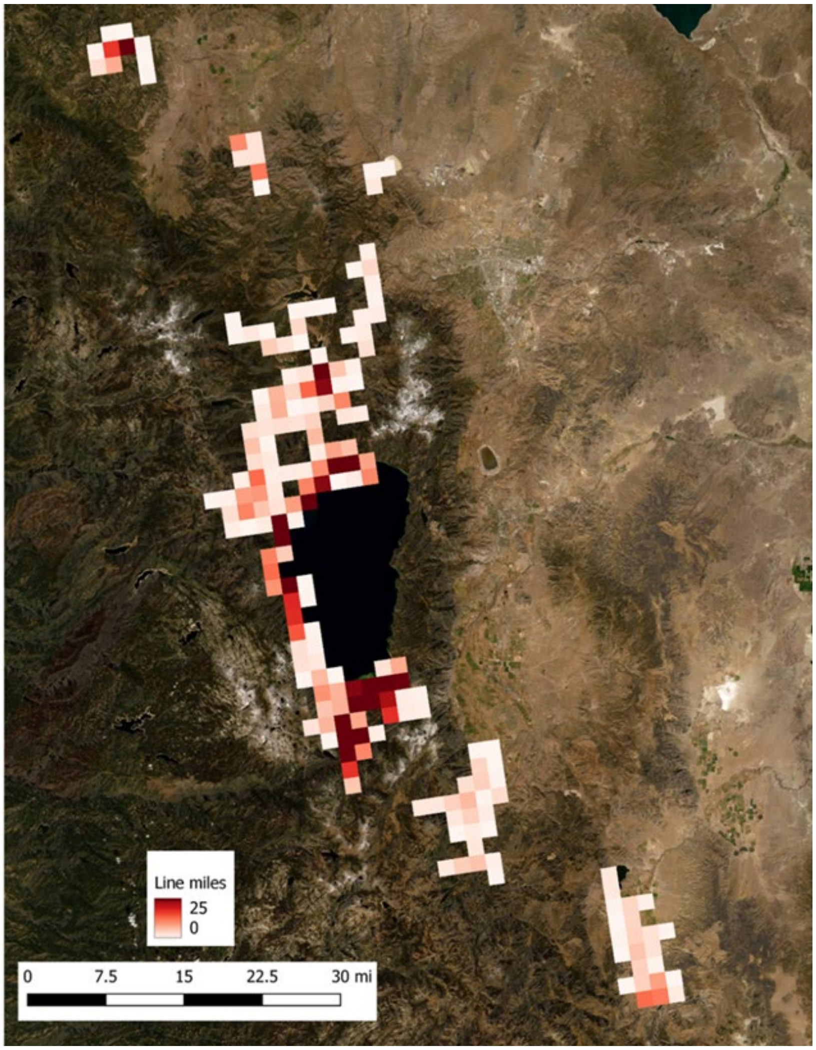
Step 1: Outage occurrence in discrete wind gust and temperature bins. Temperature was binned in 2°F increments and wind gusts were binned in two mph increments. The number of outages in each 2°F × 2 mph bin was determined from RTMA data. This is shown graphically in Figure 4.4- 1below where the colors correspond to the logarithm of the number of outages in each wind gust/temperature bin.

Figure 4.4- 1: Outage occurrence in discrete wind gust and temperature bins



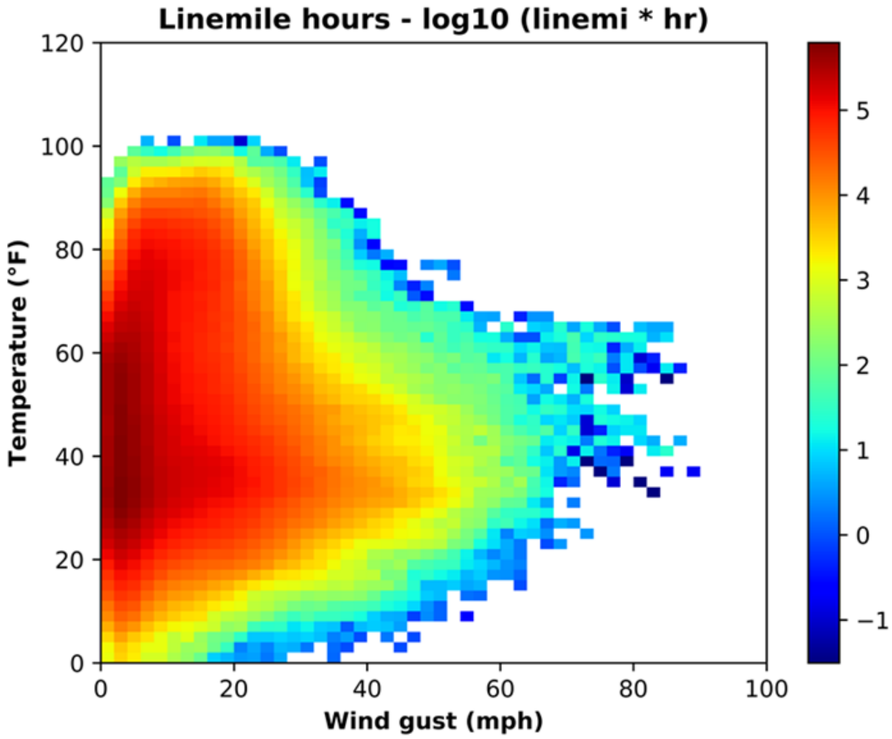
Step 2: Overhead line miles density on RTMA grid. The length of conductor in each 2.5 km RTMA grid cell was determined. Figure 4.4- 2 below shows the length of conductor (line mi) for overhead conductors, including transmission, primary distribution, and secondary distribution.

Figure 4.4- 2: Overhead line miles density on RTMA grid



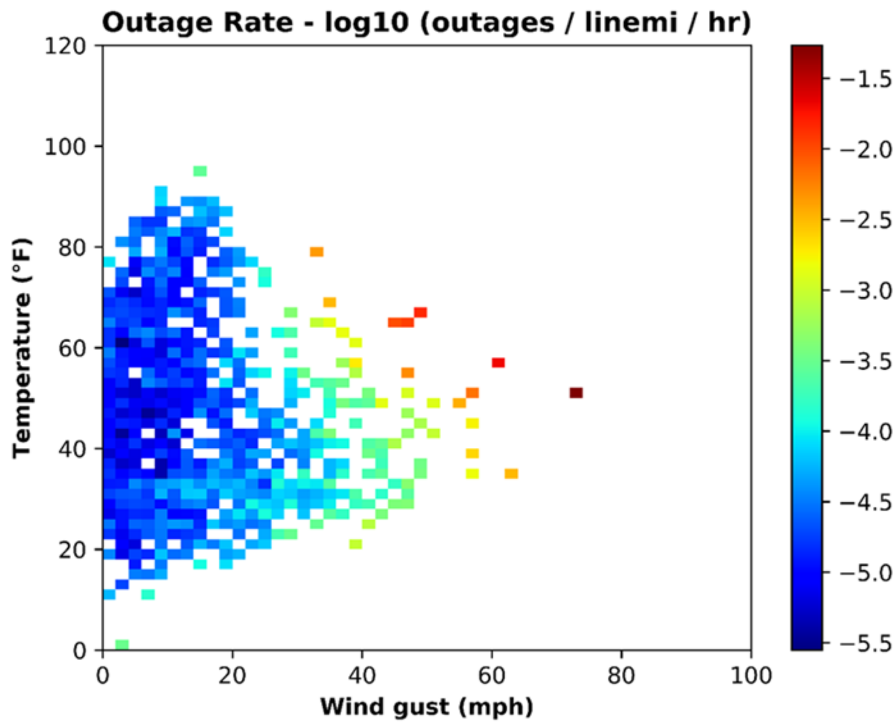
Step 3: Line mile hours per bin. The conductor density map above was used to determine the number of line mile hours that Liberty's overhead electrical system spends in discrete temperature/wind gust bins. Instead of counting outages per bin as in Step 1, line mile-hours per bin is summed. This was done by looping temporally over the RTMA climatology and, for each grid cell containing overhead electrical infrastructure, determining the corresponding 2°F × 2 mph bin. The number of line mile-hours in that bin was then incremented by the number of line mile-hours in the RTMA grid cell. This was repeated for each hour from 2017 – 2021, and the result is shown graphically in Figure 4.4- 3 below. Note that as with outage counts, a logarithmic color scale is used.

Figure 4.4- 3: Line mile hours in wind and temperature bins



Step 4: Outages per line mile hour per temperature and wind gust bin. With outages and line mile-hours now determined for each wind gust and temperature bin, outages per line mile per hour was calculated by dividing the matrix from Step 1 (outages) by the matrix from Step 3 (line mile hours). The result is shown graphically in Figure 4.4- 4 below.

Figure 4.4- 4: Outage Rate in Wind and Temperature Bins



Step 5: Correlation of outages/line miles/hour with temperature and wind gust. The data shown in Figure X above**Error! Reference source not found.** were used to correlate outage rate as a function of wind gust and temperature. The effect of wind gust and temperature on outage occurrence rate were first examined separately by plotting outage rate as a function of temperature independent of wind gust (Figure 4.4- 5) and as a function of wind gust independent of temperature (Figure 4.4- 6). Figure 4.5-5 shows that outage occurrence rate is a weak function of temperature. Conversely, outage occurrence rate is a strong function of wind gust speed, varying by over three orders of magnitude between 20 mph and 70 mph. The data in Figure 4.5-6 are well-fit by Equation 1 where OR is outage rate and ug is wind gust in mph:

$$\log_{10} \mathrm{OR} \approx \max\left(-4.7, \qquad 0.059 \times u_g - 5.7\right)$$

The red line labeled "Correlation" in Figure 4.4- 6 is a graphical representation of Equation 1.

Figure 4.4- 5: Outage Rate as a Function of Temperature Independent of Wind Gust

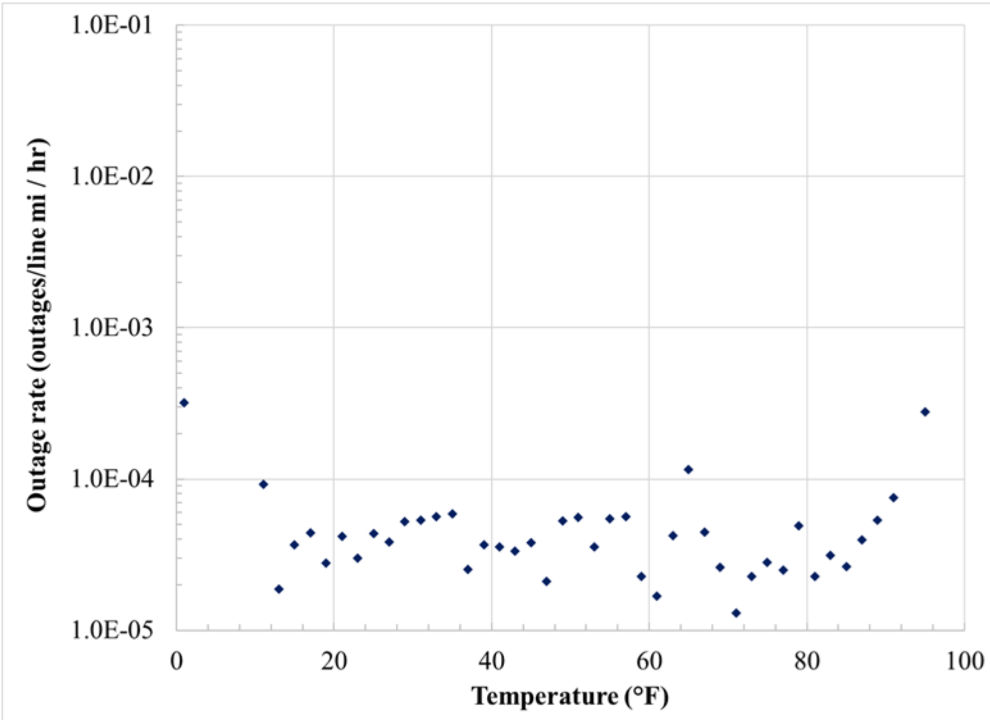
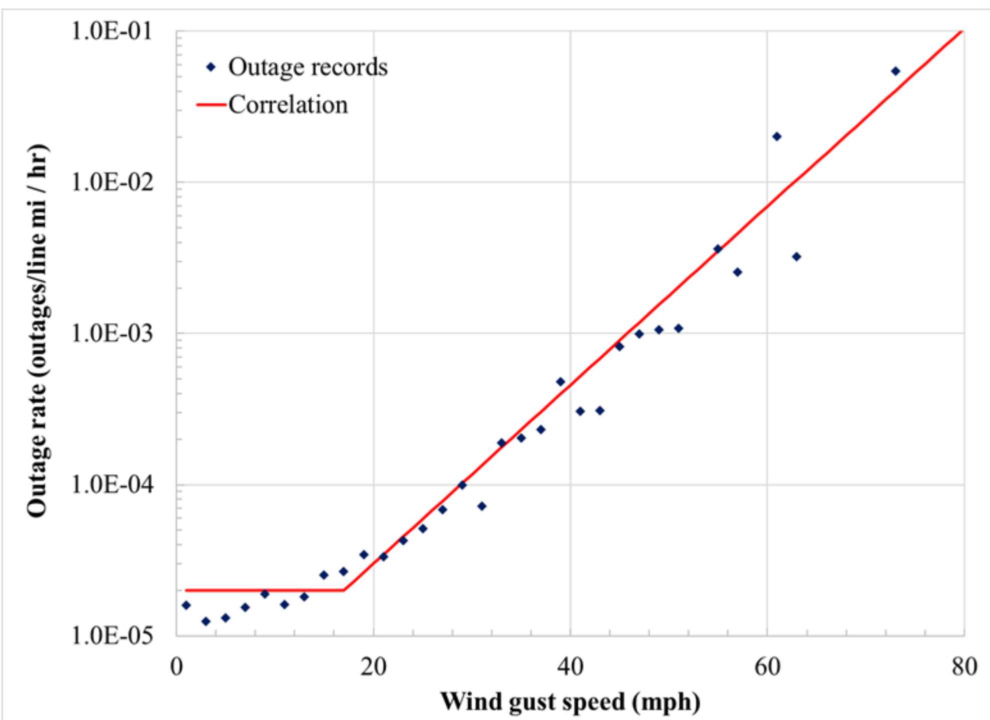


Figure 4.4- 6. Outage Rate as a Function of Wind Gust Independent of Temperature



5. ***Timeline*** – Liberty plans to conduct an outage rate study annually and will report results to OEIS. Any model or data input refinements with new readily accessible datasets will be described in Liberty's annual WMP updates.

6. ***Results and discussion*** - The outage rate analysis shows a strong correlation of forced outages to increases in wind speed and can be an indicator of outage events versus variations in temperature. Further analysis can be conducted on the outage types to isolate risk events by probability of ignition-related forced outage events. Outage rates determined from this study is a direct input in Liberty's probability of ignition model discussed in Section 4.5.1. The outage rate analysis is a vast improvement since it factors in location-specific outages, time of outage, and weather attributes and the date and time of the outages.
7. ***Follow-up planned*** - Liberty plans to conduct an outage rate study annually and will report results to OEIS.

4.5. Model and metric calculation methodologies

4.5.1. Additional models for ignition probability, wildfire and PSPS risk

Instructions*: Each utility is required to report details on the models and methodologies used to determine ignition probability, wildfire risk, and PSPS risk. This must include the following for each model – a list of all inputs, details of data elements used in the analysis, modeling assumptions and methodologies, input from Subject Matter Experts (SMEs), model verification and validation (e.g., equation(s), functions, algorithms or other validation studies), model uncertainty and accuracy, output (e.g., windspeed model) and applications of model in WMP (e.g., in selection of mitigations, decision-making).*

The narrative for each model must be organized using the headings described below. A concise summary of the model(s) must be provided in the main body of the WMP in this section, with additional detail provided for each model in an appendix.

1. ***Purpose of model*** *- Brief summary of context and goals of model*
2. ***Relevant terms*** *- Definitions of relevant terms (e.g., defining "enhanced vegetation management" for a model on vegetation-related ignitions)*
3. ***Data elements*** *- Details of data elements used for analysis. Including at minimum the following:*
    a. *Scope and granularity (or, resolution) of data in time and location (i.e., date range, spatial granularity for each data element, see example table above).*
    b. *Explain the frequency of data updates.*
    c. *Sources of data. Explain in detail measurement approaches.*
    d. *Explain in detail approaches used to verify data quality.*
    e. *Characteristics of the data (field definitions / schema, uncertainties, acquisition frequency).*
    f. *Describe any processes used to modify the data (such as adjusting vegetative fuel models for wildfire spread based on prior history and vegetation growth).*
4. ***Methodology assumptions and limitations*** *- Details of each modeling assumption, its technical basis, and the resulting limitations of the model.*
5. ***Modeling methodology*** *– Details of the modeling methodology. Including at minimum the following:*
    a. *Model equations and functions*
    b. *Any additional input from Subject Matter Experts (SME) input*
    c. *Any statistical analysis or additional algorithms used to obtain output*
    d. *Details on the automation process for automated models.*
6. ***Model uncertainty*** *– Details of the uncertainty associated with the model. This must include uncertainty related to the fundamental formulation of the model as well as due to uncertainty in model input parameters.*
7. ***Model verification and validation*** *– Details of the efforts undertaken to verify and validate the model performance. Including at minimum the following:*

a. *Documentation describing the verification basis of the model, demonstrating that the software is correctly solving the equations described in the technical approach.*
b. *Documentation describing the validation basis of the model, demonstrating the extent to which model predictions agree with real-world observations.*

8. ***Modeling frequency** – Details on how often the model is run (for example, quarterly to support risk planning versus daily to support on-going risk assessments).*
9. ***Timeline for model development** – Model initiation and development progress over time. If updated in last WMP, provide update to changes since prior report.*
10. ***Application and results** – Explain where the model has been applied, how it has informed decisions, and any metrics or information on model accuracy and effectiveness collected in the prior year.*
11. ***Key improvements from working group** – For each model, describe changes which have been implemented as a result of wildfire risk modeling working group discussions. Provide a high-level summary of recommendations from the wildfire risk modeling working group.*

4.5.1.1. Model: Ignition Rate Model ("IRM")

1. **Purpose of model** - The IRM outputs feed directly to the fire risk propagation and consequence model.
2. **Relevant terms** - Ignition Rate is a function of geospatial outage rates, historic ignitions, humidity, low fuel moisture beds, and temperature.
3. **Data elements** –

Scope	Frequency of Data	Sources	Verification	Types of Data	Modification of Data
Geospatial data	Annual download of Liberty's GIS overhead circuits	Liberty's GIS	Liberty's asset inventory database is compared GIS annually	Latitude/Longitude coordinates	None
Outage Rate Analysis (Section 4.4.2)	Annual analysis	Liberty's forced outages (2017-2021); RTMA hourly gridded weather data		Latitude/Longitude coordinates for each forced outage event; Hourly weather data plotted against each outage by data and time of event.	Liberty removed planned outages and third-party outages to only analyze forced outages for this analysis
Ignition probability table	Annual download	National Fire Danger Rating System ("NFDRS")			None

4. **Methodology assumptions and limitations** - Due to Liberty's low number of CPUC-reportable ignitions, there is an insufficient number of data points to correlate Liberty's ignition data in the same way that outage data was correlated. For this reason, several assumptions were made to estimate relative ignition rates as a function of environmental factors:
   a. Given a receptive fuel bed with zero fine dead fuel moisture content, ignition rate is proportional to forced outage rate, and
   b. Given a forced outage, the probability that the outage causes an ignition is proportional to National Fire Danger Rating System ("NFDRS") ignition probability.

5. **Modeling methodology** –
   a. Modeling equations and functions: Ignition rate (ignitions/line mile/hour):

$$\mathrm{IR} = F \times P_{ign} \times \mathrm{OR}$$

where F is the ignition-to-outage ratio for a receptive fuel bed with negligible moisture content and temperature > 80 °F, and P_{ign} is NFDRS ignition probability given a receptive fuel bed's actual moisture content and temperature. A rough estimate of F is $10^{-2} < F < 10^{-1}$. P_{ign} (NFDRS ignition probability) is a function of fine dead fuel moisture content and fuel bed temperature as shown in Table 4.5-1 below. Note that fine fuel moisture content is a function of relative humidity and temperature.

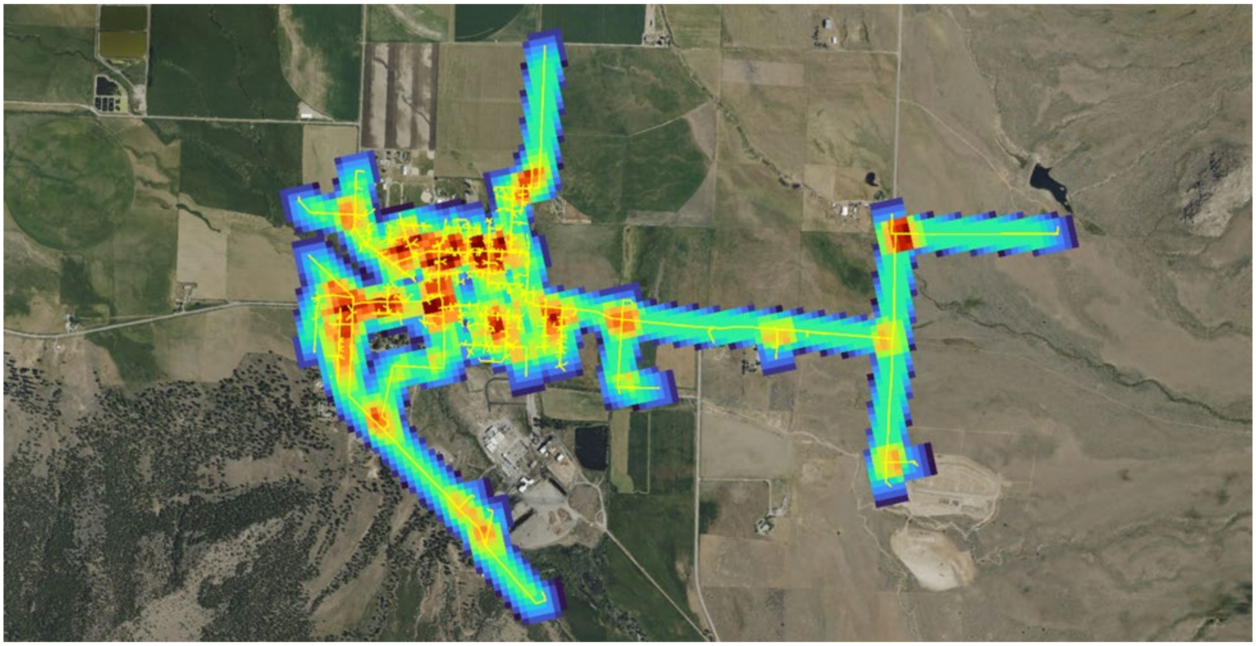
Table 4.5- 1: Ignition Probability as Function of Fine Fuel Moisture Content and Fuel Bed Temperature

Fuel	*Fine Fuel Moisture Content (%)*														
Temp (F)	*1.5*	*2.0*	*2.5*	*3.0*	*4.0*	*5.0*	*6.0*	*7-8*	*9-10*	*11-12*	*13-16*	*17-20*	*21-25*	*26-30*	*>30*
30-39	87	80	74	69	59	51	43	34	25	17	10	4	1	0	0
40-49	89	83	77	71	61	53	45	36	26	18	11	5	1	0	0
50-59	92	85	79	73	63	54	47	37	27	20	11	5	2	0	0
60-69	94	88	81	76	65	56	49	39	29	21	12	6	2	0	0
70-79	97	90	84	78	68	59	51	41	30	22	13	6	2	0	0
80-89	100	93	87	81	70	61	53	42	31	23	14	7	2	1	0
90-99	100	96	90	84	73	63	55	44	33	24	15	7	3	1	0
100-109	100	99	93	86	75	66	57	46	35	26	16	8	3	1	0
110-119	100	100	96	89	78	68	59	48	36	27	17	9	3	1	0
120-129	100	100	99	93	81	71	62	51	38	29	18	9	4	1	0
130-139	100	100	100	96	84	74	65	53	40	30	20	10	4	1	0
140-149	100	100	100	99	87	77	67	55	42	32	21	11	5	2	0
150-159	100	100	100	100	90	80	70	58	45	34	22	12	5	2	0

The estimate of ignition rate (ignitions/length/hour) as a function of wind gust speed, relative humidity, and temperature since the latter two factors influence P_{ign}. This estimate can in turn be used to estimate spatiotemporal ignition probability (ignitions/area/hour) by multiplying ignition rate by overhead network density (length/area).

   b. Additional input from Subject Matter Experts ("SMEs"): SME input included Reax engineering, wildfire mitigation team, risk model team, engineering, and operations.
   c. Statistical analysis or additional algorithms used to obtain output: Overhead conductor length (transmission, primary distribution, and secondary distribution) per unit area was calculated on the same 30 m grid that is later used for fire spread modeling. A 5 × 5 smoothing filter was used to smooth these conductor densities into adjacent grid cells since ignitions may not occur directly under powerlines. As an example, overhead conductors in part of Liberty's service territory are shown with the conductor length per unit area after smoothing is shown in Figure 4.5- 1 below.

Figure 4.5- 1: Conductor Length per Unit Area After Smoothing



6. **Model uncertainty** – Individual outage types were not identified or analyzed separately in this analysis and each outage is given equal weighting. Canopy layer over lines at the time and date of each outage is unknown and is not factored in the analysis.
7. **Model verification and validation** – Liberty did not perform any verification of model inputs.
8. **Modeling frequency** – Liberty's IRM is a static model performed annually for the WMP Update.
9. **Timeline for model development** – Liberty's IRM is a newly initiated study since its last WMP risk model approach. The outputs of the IRM includes geospatial ignition rate analysis given historic weather at the time of each forced outage event and feeds directly in the fire risk model.
10. **Application and results** –Liberty's IRM was developed earlier this year and the outputs of the IRM includes geospatial ignition rate analysis given historic weather at the time of each forced outage event and feeds directly in the fire risk model.
11. **Key improvements from working group** – N/A

4.5.1.2. Model: Consequence Modeling from Wildfire Risk Model

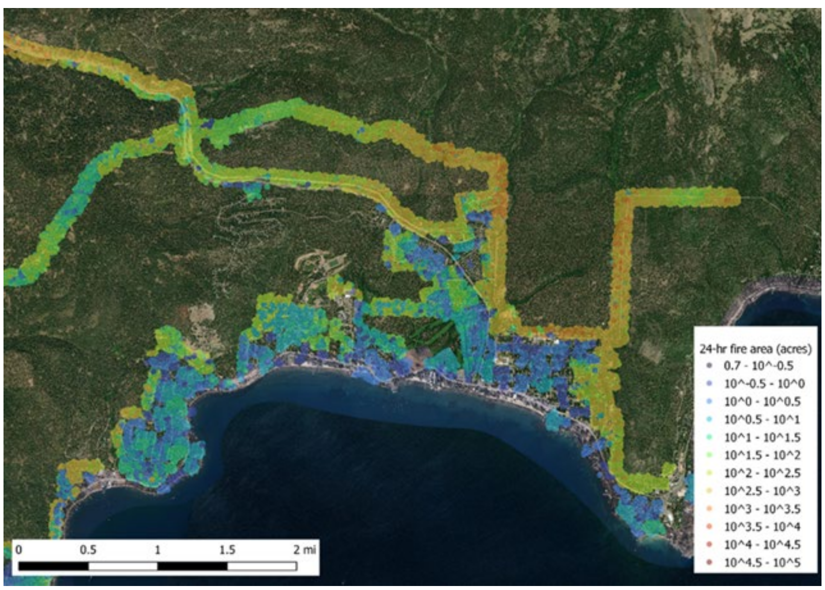
1. **Purpose of model** - Ignition line mile rates are fed into the fire propagation model to estimate consequences of simulated fires.
2. **Relevant terms** - Risk is the ignition probability multiplied by the consequence of utility started wildfire.

3. **Data elements** –

Scope	Frequency of Data	Sources	Verification	Types of Data	Modification of Data
Geospatial data	Annual download of Liberty's GIS overhead circuits.	Liberty's GIS	Liberty's asset inventory database is compared GIS annually	Latitude/Longitude coordinates	None
Ignition Rate Analysis (Section 4.5.1.1)	Annual analysis	Liberty's forced outages (2017-2021); RTMA hourly gridded weather data; National Fire Danger Rating System ("NFDRS")	None	Summary of overhead network density, wind gust, relative humidity, and temperature	None
Fire Spread Model	Annual	Eulerian Level set Model of FIRE spread ("ELMFIRE")	None		
2021 Climatology/Weather	Annual analysis	National Oceanic and Atmospheric Administration ("NOAA"); National Centers for Environmental Prediction ("NCEP"); Real Time Mesoscale Analysis ("RTMA")	None	This dataset provides hourly gridded fields of temperature, relative humidity, wind speed, and direction at 2.5 km resolution from 2011 – current.	Since wind gust data are most reliable after 2016, a 6-year block spanning 2016-2021 was used in the modeling.
2050 Climatology/Weather	Annual analysis	Dynamically downscaled Weather Research and Forecasting ("WRF") initialized with global climate models from the 6th Coupled Model Intercomparison Project ("CMIP6")	None	This provides hourly gridded fields of temperature, relative humidity, wind speed, and wind direction at 3 km resolution.	A 6-year temporal block from years 2048 – 2053 was selected for analysis.
Fuel & topography		Pyrologix 2021 California Fuelscape prepared for USFS Region 5		This dataset provides surface and canopy fuel layers and topography at 30 m resolution.	No adjustments are made for 2050 conditions. Due to several 2021 fires in Liberty's service territory that are not reflected in this dataset, models will be re-run later this year when the 2022 California Fuelscape data become available.
Structures		Microsoft building footprint dataset			No adjustments are made for 2050 conditions.

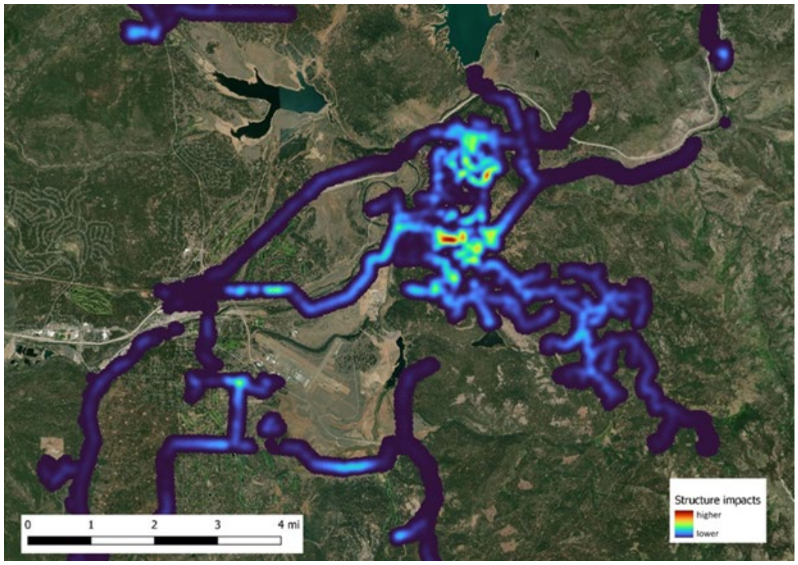
4. **Methodology assumptions and limitations** – Fire risk modeling starts by incrementally looping over each hour in the climatology data (RTMA for 2021, downscaled WRF for 2050):
    a. Spatial variations in ignition rate (ignitions/line mile/hour) are calculated from wind gust, fine dead fuel moisture, and temperature.
    b. Spatial variations in ignition rate per unit area (ignitions/area/hour) are calculated by multiplying conductor length per unit area by ignition rate per line mile per hour.
    c. Total number of ignitions is determined by spatially integrating ignition rate per unit area and multiplying by a large-scale factor which is equivalent to modeling ignition patterns over tens of thousands of years.
    d. The number of ignitions is distributed across the landscape in a pattern that is proportional to the ignition density surface.
    e. For each ignition location, fire spread is modeled for 24 hours.
    f. At the end of 24 hours, total fire area, timber impacts, and number of impacted structures are recorded for the ignition location, and the next ignition is processed.
    g. Approximately 4.5 million ignitions were modeled under 2021 conditions, and approximately 7.9 million ignitions under 2050 conditions.
5. **Modeling methodology** – Fire size, timber impacts, and number of impacted structures were recorded in a shapefile for each of the approximately 12.5 million modeled ignitions. Sample data (modeled fire area by ignition point, log scale, 2021 climatology) is shown below in Figure 4.5- 2.

Figure 4.5- 2: Sample Modeled Fire Area



Kernel density estimation, with ignition points weighted by area/structures/timber, was used to distill the millions of modeled ignitions into rasterized risk heat maps. An example depicting potential structure impacts near Truckee is shown in Figure 4.5- 3 below. Warmer colors correspond to higher relative risk (probability of ignition multiplied by structure impacts) and cooler colors correspond to lower relative risk. Since secondary overhead lines are included in the ignition density surface, areas with a high density of secondary overhead may show up as hot spots. An additional analysis with only primary overhead lines used for modeling ignition density may give slightly different results.

Figure 4.5- 3: Potential Structure Impacts



Zonal statistics were generated for each circuit to summarize fire model outputs at the circuit level. For each circuit, structure impacts, fire area, and timber impacts were tabulated at the following percentiles: 50, 60, 70, 80, 90, 95, 97, 98, 99, 99.9. For example, 50th percentile fire area is the median modeled fire size for a circuit.

Table 4.5- 2: Fire Model Outputs at Circuit Level

	Circuit	Fire area (acres) by percentile									
		50th	60th	70th	80th	90th	95th	97th	98th	99th	99.9th
Transmission	111 - 120 KV (Meyers-Buckeye)	484.4	649.8	843.3	1083.1	1465.8	1854.1	2115.0	2302.7	2603.3	3434.0
	608 - 60kV (Hirschdale Line Tie)	77.8	126.5	190.8	294.0	454.4	593.1	669.9	739.9	869.3	1513.2
	619 - 60kV (Portola-Truckee)	408.1	572.4	691.0	818.0	1006.3	1272.1	1471.6	1634.2	1924.8	2915.8
	650 - 60kV (Truckee-Kings Beach)	148.6	222.2	337.2	523.3	811.1	1100.0	1326.1	1516.5	1832.1	2969.0
	634 - 60kV (Stateline-Buckeye)	252.9	314.9	381.9	474.6	615.4	742.1	836.0	951.2	1123.3	1643.5
	608 - 60kV (Truckee-North Truckee-I-80)	126.3	174.6	250.2	364.1	497.7	606.2	705.7	810.0	1019.0	1728.9
	160 - 120 KV (Round Hill-Cal Border)	243.7	304.5	368.3	468.1	613.4	746.6	843.5	943.6	1131.3	1588.1
	629 - 60kV (Squaw Valley-Tahoe City)	194.6	231.7	276.0	337.8	430.8	510.8	567.1	610.5	692.5	1052.8
	609 - 60kV (Truckee-Squaw Valley)	302.9	381.4	477.3	613.6	898.0	1172.5	1361.9	1524.7	1879.7	3709.1
	669 - 60kV (Northstar-Kings Beach)	141.2	208.2	285.6	373.0	548.9	723.2	838.2	929.2	1114.0	1839.0
	621 - 60kV	4.2	5.8	6.4	12.2	61.6	99.2	159.2	238.2	300.7	572.0
	640 - 60kV (Meyers-Stateline)	122.3	209.3	312.2	464.6	746.4	983.2	1152.4	1288.8	1521.4	2334.3
	132 - 120 KV (Truckee-Squaw Valley)	118.3	183.5	278.9	408.5	599.6	843.8	1035.9	1178.7	1434.0	2562.2
	608 - 60kV (Truckee-Washoe)	143.4	227.3	340.5	504.6	752.1	983.0	1138.4	1257.6	1448.9	2296.0
	625 - 60kV (Tahoe City-Kings Beach)	83.8	114.8	162.1	245.5	363.4	524.6	644.3	726.6	850.4	1226.1

6. **Model uncertainty** –
    a. Ignition probability was modeled from empirical outage data; differences in system operation (reclosing, fast trip), maintenance, vegetation management, were not accounted for.
    b. Insufficient outage data for differences between outage rates on distribution and transmission lines.
    c. Fires were modeled as unsuppressed for a duration of 24-hours because operational fire models cannot currently reliably model fire suppression.
    d. Fire spread through urban/built up areas that are marked as non-burnable in underlying fuel inputs is not modeled. Impacted structure values were tallied as the number of structures within a modeled fire perimeter and do not necessarily correspond to damaged or destroyed structures.

Factors that affect structure vulnerability (*e.g.*, roof and exterior wall construction, defensible space, etc.) were not addressed.

e. There is considerable uncertainty around future climate conditions and the modeled future climate data is based on a single near-worst-case climate scenario. Climate-adjusted determinist fire spread modeling is an active research area.

f. For future/2050 climate-adjusted modeling, fuels and structure footprints were kept constant at the current/2021 baseline.

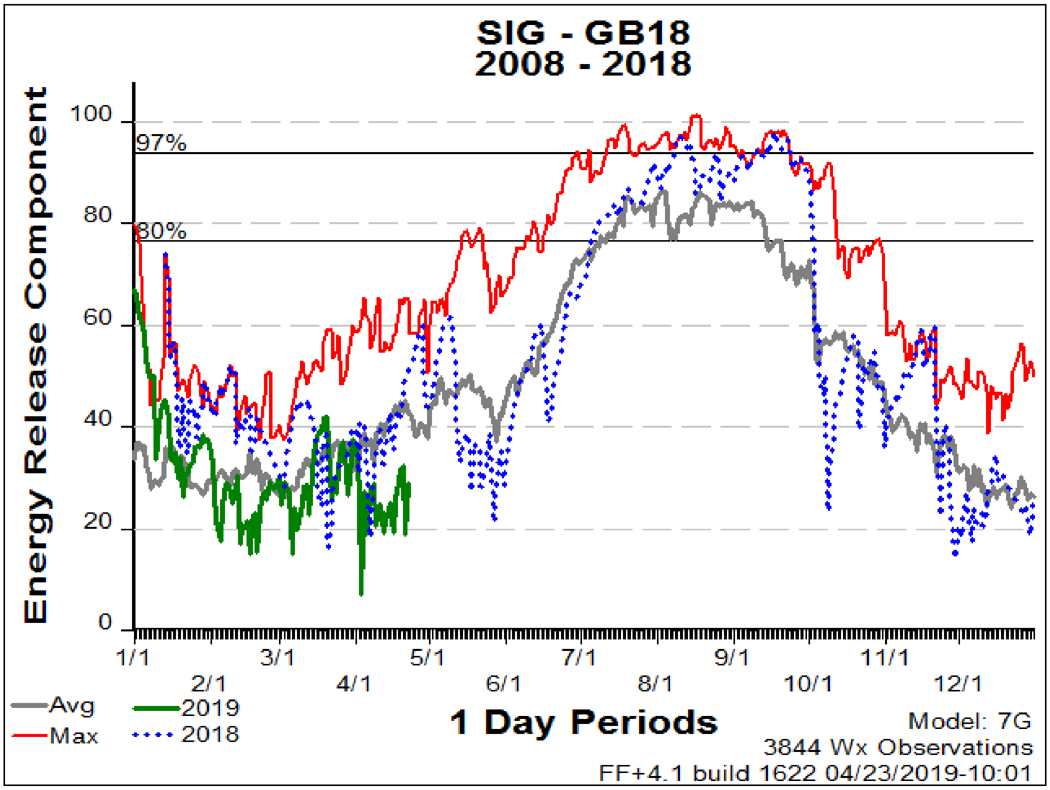
7. **Model verification and validation** – None
8. **Modeling frequency** – Annually
9. **Timeline for model development** –Prior to WMP Update
10. **Application and results** – Liberty incorporates the results of Reax's analysis into its consequence modeling for utility wildfire risk. Consequences that will utilize the outputs from Reax's models will include safety, financial, and environmental consequences. All potential factors were considered in assigning an overall wildfire risk rating to the various polygons in Liberty's service territory.
11. **Key improvements from working group** – N/A

4.5.1.3. Model: Fire Potential Index ("FPI")

1. **Purpose of model** - The FPI is intended to communicate daily localized wildfire potential using easily understood classifications (low, medium, high, very high, and extreme) to forecast wildfire potential for the next week.
2. **Relevant terms** - Burning Index ("BI") - An estimate of the potential difficulty of fire containment as it relates to the flame length at the head of the fire; Energy Release Component ("ERC") - The computed total heat release per unit area (Btu/ft2) within the flaming front at the head of a moving fire; National Fire Danger Rating System ("NFDRS") - the United States' fire danger rating system intended to quantify fire threat and relative severity of burning conditions.
3. **Data elements** - As described in the methodology section below, Liberty's FPI is calculated from two NFDRS indices. The first index, ERC, quantifies intermediate to long-term dryness. The second index, BI, quantifies its proportion to flame length of a head fire and is directly related to fire suppression effectiveness and difficulty of fire containment.

   ERC is calculated from Remote Automated Weather Station ("RAWS") observations as part of the NFDRS. A given ERC value is 4% of the energy per unit area, in units of Btu/ft2, that would be released during a fire. Therefore, multiplying an ERC value by 25 gives the number of Btu per square foot that would be released in the flaming front of a fire. ERC depends on live and dead fuel loading by size class (as characterized by an NFDRS fuel model), as well as fuel moisture content of live and dead fuels. In addition to dependence on fuel loading assigned to each fuel model, ERC varies due to changes in moisture content of both live and dead fuels, which are, in turn, dependent on prior precipitation, relative humidity, and temperature. Figure 4.5- 4 below shows a representative yearly variation in ERC in the Western U.S. Because ERC depends on fuel loading/fuel model at each RAWS, absolute ERC values are usually converted to percentiles to facilitate comparison of seasonal ERC trends between RAWS stations with different fuel models.

Figure 4.5- 4: Representative Yearly Variation in ERC in the Western US



BI is conventionally interpreted as head fire flame length, in feet, multiplied by 10. For example, a BI of 80 corresponds to a head fire flame length of approximately eight feet. BI is more sensitive to short-term fluctuations in environmental conditions, particularly wind, than ERC.

4. **Methodology assumptions and limitations** - For fire danger rating purposes, ERC and BI are often normalized against historical weather conditions so they can be reported as percentiles, which may provide a better indication of fire danger than absolute values. For the purposes of calculating Liberty's FPI, ERC and BI percentile forecasts are obtained from the U.S. Forest Service ("USFS") Wildland Fire Assessment System ("WFAS") (https://wfas.net).
5. **Modeling methodology** - A 2019 USFS study demonstrated that a simple fire danger index that combines ERC and BI percentiles is strongly correlated with historical fire occurrence and ultimate fire size. Analysis of historical fire records (Figure 4.5-5) has shown that 13% of new fires and 33% of eventual burned area occurred when fires were ignited when ERC and BI were both above 90th percentile. Similarly, 28% of new fire reports and 57% of eventual acres burned occurred when both indices were above 80th percentile. Leveraging these findings, Liberty's FPI is calculated by converting ERC and BI percentiles obtained from the USFS WFAS into FPI adjectives using Figure 4.5-6.

Figure 4.5- 5: New fire reports (a) and eventual acres burned (b) as a function of ERC and BI percentiles. Color scales indicate the amount of fire activity observed in each joint bin and the percentages indicate the proportion of fire activity observed in each joint bin

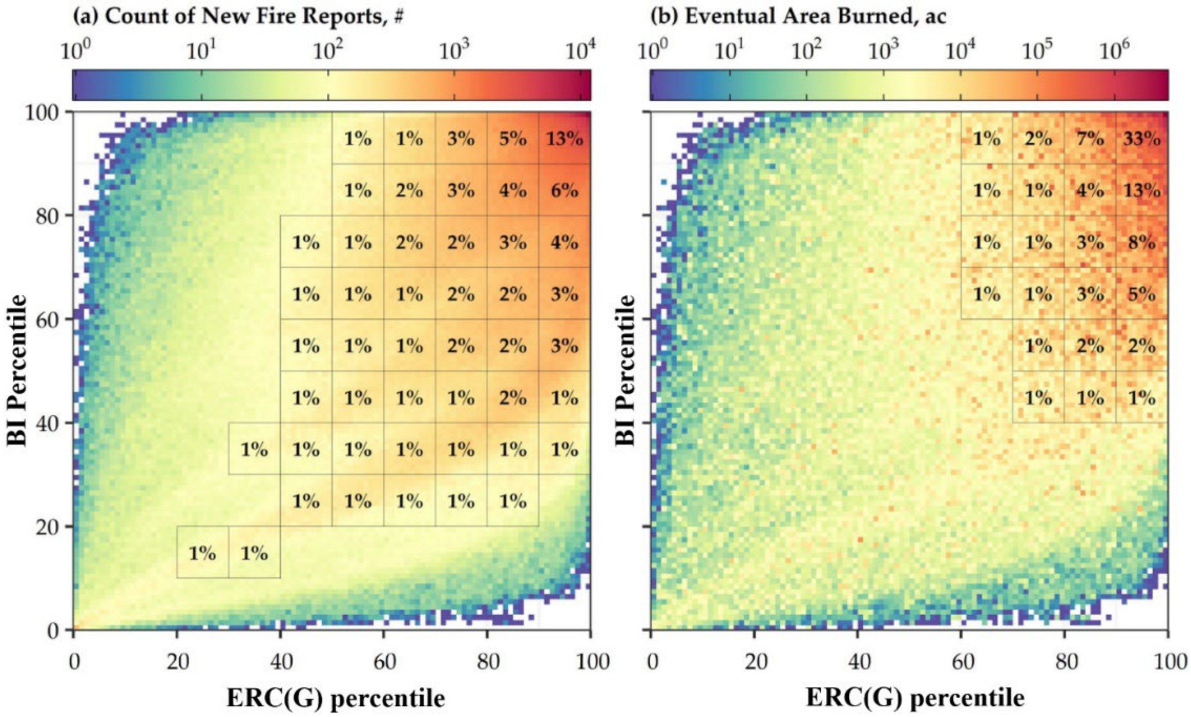


Figure 4.5- 6: Liberty FPI Ratings and a Function of ERC and BI Percentiles

BI Percentile						
	97-100					Extreme
	90-97				Very High	
	80-90			High		
	60-80		Moderate			
	0-60	Low				
		0-60	60-80	80-90	90-97	97-100
		ERC Percentile				

6. **Model uncertainty** – TBD
7. **Model verification and validation** – None
8. **Modeling frequency** – TBD; as updates are identified.
9. **Timeline for model development** – Liberty introduced the FPI to support operations at the start of the 2020 fire season. Assessment of the model, enhancements to the automated analytics and monitoring system, and other verification efforts are ongoing.
10. **Application and results** – FPI is used to inform reactive and proactive operational practices through standard operating procedures. Use of the FPI is expected to enable Liberty to reduce the probability of its facilities and operations leading to an ignition, especially during times of elevated wildfire risk.
11. **Key improvements from working group** – None at this time.

4.5.2. Calculation of key metrics

***Instructions**: Report details on the calculation of the metrics below. For each metric, a standard definition is provided with statute cited where relevant. The utility must follow the definition provided and detail the procedure they used to calculate the metric values aligned with these definitions. The utility must cite all data sources used in calculating the metrics below. In addition, the utility must include GIS layers showing Red Flag Warning (RFW) frequency and High Wind Warning (HWW) frequency (use data from the previous 5 years, 2016-2021), as well as GIS layers for distribution of Access Functional Need (AFN) customers, and urban/rural/highly rural customers, and disadvantaged communities[8] in its service territory.*

1. ***Red Flag Warning overhead circuit mile days** - Detail the steps to calculate the annual number of red flag warning (RFW) overhead (OH) circuit mile days. Calculate as the number of circuit miles that are under an RFW multiplied by the number of days those miles are under said RFW. Refer to the National Weather Service (NWS) Red Flag Warnings. For historical NWS RFW data, refer to the Iowa State University archive of NWS watch / warnings.[9] Detail the steps used to determine if an overhead circuit mile is under a RFW, providing an example of how the RFW OH circuit mile days are calculated for a RFW that occurred within the utility service territory over the last five years.*
2. ***High Wind Warning overhead circuit mile days** – Detail the steps used to calculate the annual number of High Wind Warning (HWW) overhead circuit mile days. Calculate as the number of OH circuit miles that are under an HWW multiplied by the number of days those miles are under said HWW. Refer to High Wind Warnings as issued by the National Weather Service (NWS). For historical NWS data, refer to the Iowa State University archive of NWS watch / warnings.[10] Detail the steps used to determine if an OH circuit mile is under a HWW, providing an example of how the OH HWW circuit mile days are calculated for a HWW that occurred within the utility service territory over the last five years.*
3. ***Access and Functional Needs population** – Detail the steps to calculate the annual number of customers that are considered part of the Access and Functional Needs (AFN) population. Defined in Government Code § 8593.3 and D.19-05-042 as individuals who have developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking,[11] 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.*

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8 Energy Safety recommends using CalEnviroScreen and Senate Bill 535 to identify disadvantaged communities.
9 https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml.
10 https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml.
11 Guidance on calculating number of households with limited or no English proficiency can be found in D.20-04-003.

4. ***Wildlife Urban Interface*** *– Detail the steps to calculate the annual number of circuit miles and customers in wildland-urban interface (WUI) territory. WUI is defined as the area where houses exist at more than 1 housing unit per 40 acres and (1) wildland vegetation covers more than 50% of the land area (intermix WUI) or (2) wildland vegetation covers less than 50% of the land area, but a large area (over 1,235 acres) covered with more than 75% wildland vegetation is within 1.5 mi (interface WUI) (Radeloff et al, 2005).*[12]
5. ***Urban, rural and highly rural*** *– Detail the steps for calculating the number of customers and circuit miles in utility territory that are in highly rural, rural, and urban regions for each year. Use the following definitions for classifying an area highly rural/rural/urban (also referenced in glossary):*
    a. *Highly rural – In accordance with 38 CFR 17.701, "highly rural" must be defined as those areas with a population of less than 7 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, "area" must be defined as census tracts.*
    b. *Rural – In accordance with GO 165, "rural" must be defined as those areas with a population of less than 1,000 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, "area" must be defined as census tracts.*
    c. *Urban – In accordance with GO 165, "urban" must be defined as those areas with a population of more than 1,000 persons per square mile as determined by the United States Bureau of the Census. For the purposes of the WMP, "area" must be defined as census tracts.*

    Population density numbers are calculated using the American Community Survey (ACS) 1-year estimates on population density by census tract for each corresponding year (2016 ACS 1-year estimate for 2016 metrics, 2017 ACS 1-year estimate for 2017 metrics, etc.). For years with no ACS 1-year estimate available, use the 1-year estimate immediately before the missing year (use 2019 estimate if 2020 estimate is not yet published, etc.).

1. Red Flag Warning overhead circuit mile days – First, the NWS watch/warning shapefiles are downloaded from Iowa State's archive for the past five years. The archive is then filtered to separate Red Flag Warning ("RFW") events. Next, the RFW shapefile is clipped to Liberty's service territory, and the duration of the RFW is calculated using the difference between the start and end times. The resultant shapefile overlaid on Liberty's GIS allows for the calculation of RFW circuit mile days.
2. High Wind Warning overhead circuit mile days – The process for calculating High Wind Warning overhead circuit mile days is identical to the above except the Iowa State NWS archive is filtered for High Wind Warnings.
3. Access and Functional Needs (AFN) population – Liberty tracks the following categories within Liberty's databases to be AFN: customers enrolled in the California Alternate Rates for Energy (CARE) Program and the Medical Baseline ("MBL") Program. As of April 3, 2022, there are 2,947 CARE customers and 256 MBL customers in Liberty's service territory.
4. Wildland Urban Interface – WUI polygons for the State of California were downloaded from the following website: http://silvis.forest.wisc.edu/data/wui-change/. For the calculation, the field "Wuiflag10" was used. According to the website, WUI polygon consists of interface or urban (wuiflag10=2) and intermix or rural (wuiflag10=1). The annual number of circuit miles and customers in the WUI polygons was calculated using spatial analysis. The mileage and customer count were recalculated in newly created output and reported. The sources of the data were Liberty distribution/transmission lines and meter location data layer.
5. Urban, rural and highlight rural – To populate circuit miles and number of customers in urban, rural, and highly rural areas, Liberty used U.S. Census Bureau, 2015-2019 American Community Survey 5-Year

[12] Paper can be found here - https://www.fs.fed.us/pnw/pubs/journals/pnw_2005_radeloff001.pdf with the latest WUI map (form 2010) found here - http://silvis.forest.wisc.edu/data/wui-change/

Estimates. Population density was calculated per each census tract, which was then used to determine if the tract falls under urban (>1,000 people), rural (seven-999 people), or highly rural (fewer than seven people). Geospatial overlay of Liberty's circuits and meters within urban, rural, and highly rural areas was performed, and then Liberty calculated the total number of meters and circuit miles within each category.

4.6. Progress reporting on key areas of improvement

***Instructions**: Report progress on all key areas of improvement identified in Section 1.3 of the utility's 2021 Action Statement. Provide a summary table of the actions taken to address these key areas and report on progress made over the year. Summarize the progress in a table using a high-level bullet point list of key actions, strategies, schedule, timeline for completion, quantifiable performance-metrics, measurable targets, etc. The table must also include a cross-referenced link to a more detailed narrative and substantiation of progress in an Appendix. The summary table must follow the format illustrated in Table 4.6- 1.*

Table 4.6- 1: Progress on Key Areas of Improvement and Remedies, 2021

Utility-#	Issue title	Summary of Progress
Liberty-1	No climate-driven risk mapping	In its updated risk modeling analysis completed in early 2022, Liberty considered future climate projections. Mid-century (2050) projected meteorological inputs were obtained from a recently published dataset in which Global Circulation Model ("GCM") data from the Coupled Model Intercomparison Project ("CMIP6") was downscaled to 3-km resolution using Weather Research and Forecasting ("WRF"). CMIP6 includes variability in Representative Concentration Pathways ("RCP"), allowing researchers to examine worst case (SSP5-8.5), middle of the road (SSP3-7.0) and more optimistic (SSP4-6.0) outcomes based on failure or success in enacting climate policies. Refer to Section 4.5.1.2.
Liberty-2	Lack of consistency in approach to wildfire risk modeling across utilities	Liberty participated in the Energy Safety WMP Risk Modeling Workshop on October 5-6, 2021. At the workshop, Liberty presented information about its WMP Risk Model. In addition, Liberty submitted its WMP Risk Model Workplan to Energy Safety on October 13, 2021. Liberty actively participates in the Energy Safety WMP Joint IOU Risk Modeling Working Group and collaborates with other utilities and stakeholders to increase risk modeling process transparency. Refer to Section 4.

Utility-#	Issue title	Summary of Progress
Liberty-3	Limited evidence to support the effectiveness of covered conductor (CC)	Liberty participated in the Joint Utility CC Working Group and contributed to the Joint Utility CC Working Group Report. Refer to Attachment D: Joint IOU Covered Conductor Effectiveness Report
Liberty-4	Lack of current inspection QA/QC Program	Liberty developed a QA/QC program for asset inspections and implemented the program in 2022. Refer to Attachment F: Liberty Asset Inspection QA/QC Program
Liberty-5	Lack of improvement to visual and detailed asset inspections that specifically target assets and asset components with high ignition risk and areas of highest wildfire risk	Liberty remediated Level 1 findings in 2020, regardless of fire risk, and developed an operational plan for prioritizing Level 2 findings by HFTD tier and fire risk. Liberty used the detailed inspection results from the system survey and subject matter expertise to identify high ignition risk assets that were incorporated in the overall evaluation of fire risk by circuit. Liberty's operations will use the fire risk identifiers to develop a comprehensive inspection program of existing assets. Additionally, Liberty is developing an approach for Level 3 findings that will be based on Liberty's updated fire risk map and Liberty's pole risk assessment discussed in Section 4.3. Liberty will utilize its Pole Risk of Failure categories of low, medium, and high. For example, a pole that is at a Level 3 priority could be because there was an issue to the high voltage signage. While this condition does need to be remediated within five years, the condition will not result in a pole falling in-service, thus has a low risk of failure. However, if a Level 3 pole has a condition code of cracked pole, the risk of failure is moderate due to the structural integrity being compromised
Liberty-6	Inadequate justification of VM inspection frequency	Liberty addressed this OEIS remedy in detail in its November 1, 2021 WMP Progress Report. Additionally, Liberty plans to conduct LiDAR vegetation management inspections annually starting with its 2021 LiDAR inspection. Refer to Sections 7.3.5.2, 7.3.5.6, 7.3.5.7, and 7.3.5.11 for information regarding vegetation management inspections.

Utility-#	Issue title	Summary of Progress
Liberty-7	Equivocating language used to describe risk-based decision-making improvements	Liberty reports on its WMP risk-based decision-making in measurable, quantifiable, and verifiable language in Section 4 of this 2022 WMP Update and its WMP Risk Model Workplan, submitted to Energy Safety on October 13, 2021. Liberty recently completed updates to its second iteration of wildfire risk modeling. As Liberty's modeling methodologies are refined, and as the models are updated with more current data, the confidence level of modeling results will increase. With this increased confidence, Liberty intends to continue to share in a more quantifiable way how its risk modeling assists in making wildfire mitigation decisions. Refer to Section 4.
Liberty-8	Limited discussion on reduction of size, scale, and frequency of PSPS	Liberty is pursuing the following WMP initiatives related to PSPS impact: 1) Use of microgrids and backup batteries to reduce the scope of potential PSPS events; 2) Utilizing both its old and new PSPS decision tree based on situation; 3) Evaluating the use of fast trips with fault indicators as a tool to lower ignition possibility, mitigate PSPS impacts, and restore service more quickly; 4) Grid hardening efforts such as covered conductor. Refer to Section 8.

5. INPUTS TO THE PLAN AND DIRECTIONAL VISION FOR WMP

5.1. Goal of Wildfire Mitigation Plan

***Instructions**: The goal of the WMPs is shared across Energy Safety and all utilities: Documented reductions in the number of ignitions caused by utility actions or equipment and minimization of the societal consequences (with specific consideration to the impact on AFN populations and marginalized communities) of both wildfires and the mitigations employed to reduce them, including PSPS.*

The following sub-sections report utility-specific objectives and program targets towards the WMP goal. No utility response is required for Section 5.1.

5.2. The objectives of the plan

***Instructions**: Objectives are unique to the utility and reflect the 1, 3, and 10-year projections of progress towards WMP goals. Objectives are determined by the portfolio of mitigation strategies proposed in the WMP. The objectives of the plan must, at a minimum, be consistent with the requirements of California Pub. Util. Code §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.*

Describe utility WMP objectives, categorized by each of the following timeframes, highlighting changes since the prior WMP:

1. *Before the next Annual WMP Update*
2. *Within the next 3 years*
3. *Within the next 10 years – long-term planning beyond the 3-year cycle*

In accordance with Cal. Pub. Util. Code § 8386(a), Liberty constructs, maintains, and operates its electric system in a manner that minimizes the risk of catastrophic wildfire posed by its electric power lines and equipment. Liberty's overarching WMP goal is to prevent and mitigate the risk of wildfires caused by utility equipment. Liberty's 2022 WMP Update continues to focus on reducing wildfire risk. Each year, Liberty identifies ways to enhance its wildfire prevention and mitigation efforts through enhancing or expanding existing programs and developing and implementing new programs.

In 2022, Liberty will continue to make progress on the initiatives outlined in its 2021 and 2022 WMP Updates. Near-term mitigation strategy objectives before the 2023 WMP Update are provided in Table 7.1-1 and discussed further in Section 7.3: Detailed Wildfire Mitigation Programs. Liberty provides details on its three year and ten year vision in Table 5.2- 1.

Table 5.2- 1: Liberty's 3- and 10-Year Vision for Wildfire Risk Mitigation

WMP Category	Three Years (2021-2023)	Ten Years (2021-2030)
Risk Assessment & Mapping	Continue developing its risk modeling team and capabilities. Continue working with Reax to refine fire spread modeling consequence in its wildfire risk modeling process. This includes integrating updated data into the analysis used for Liberty's wildfire risk models. Liberty project managers will continue to utilize the fire risk map and circuit risk analysis to inform discussions around prioritizing WMP initiative work.	Liberty anticipates greater technological advancement, as well as the maturity, quality, and robustness of the company's datasets to give more accurate predictive capabilities in its wildfire risk models.
Situational Awareness	Continue to fully integrate situational awareness tools and applications into system operations and monitoring of conditions. Utilize data from weather stations, regional camera networks, and FPI assessments to alert operations of heightened fire risk and communicate to field operations and system control operators to adjust work conditions. Evaluate and compare results of new Burning Index added to Liberty's FPI assessment in 2021 that will enable further granularity in the area of alternative responses to initiating a PSPS, such as managing recloser technology, de-energizing specific circuits and/or increasing patrols in specific geographic areas. Continue efforts to research new sectionalizing devices and innovations in pre-fault indicators to improve PSPS mitigation efforts in the future. Pilot a fault indicators program in 2022 on two circuits in Liberty's Tier 3 HFTD region.	Continue efforts to research new sectionalizing devices and innovations in pre-fault indicators to improve PSPS mitigation efforts in the future. Fully implement technology to anticipate system failures before they pose a problem using such technology as HIFD and DFA.
Grid Design and System Hardening	Liberty plans to complete covered conductor projects as discussed in Section 7.3.3.3. Complete the remaining G.O. 165 Level 2 pole replacements in 2022 and plans to target Level 3 findings in its highest fire risk areas first. Additionally, Liberty will continue to replace poles as a result of its intrusive pole inspection program and other asset inspections. See Section 7.3.3.7. Maintain target of 1,500 fuse replacement per year until all the approximately 9,000 fuses in Liberty's HFTD Tier 2 and Tier 3 areas are replaced. As part of its Other Corrective Actions WMP initiative, Liberty plans to remove 60 tree attachments per year, targeting higher threat trees and areas of the system. Liberty also plans to install	Collect and analyze performance of covered conductor to refine assumptions of its effectiveness Implement and build resiliency corridors with covered conductors and microgrids. See Attachment B for information on Liberty's Resiliency Program. Complete all G.O. 165 pole replacements and will continue to replace poles as a result of its intrusive pole inspection program and any additional findings from its asset inspection programs. Maintain target of 1,500 fuse replacement per year until all the approximately 9,000 fuses in Liberty's HFTD Tier 2 and Tier 3 areas are replaced.

WMP Category	Three Years (2021-2023)	Ten Years (2021-2030)
	four substation animal guards in 2022 and establish annual targets for CAL FIRE exempt hardware and open wire/grey wire. Evaluation of other substation rebuilds where oil equipment and wood structures exist and continue OCB replacements. Explore substation enhancements to include capability to house future battery energy storage System ("BESS"), if deemed necessary. Develop communication plan to educate and inform customers of new program offerings and battery storage options and fees.	Fully rebuild or refurbish all substations in Liberty territory. Have substation maintenance program in place.
Asset Management and Inspections	Focus on maintaining compliance with G.O. 165 and improving the safety and reliability of the electrical system through thorough inspections of assets in the field: • Ongoing intrusive pole inspections and PTT; prioritize by wildfire risk; • Detailed and patrol inspections • Infrared inspections pilot in 2023 on both distribution and substation assets (scoping in 2022) Implement QA/QC program for asset inspections in 2022. See Section 7.3.4.14 for program details. Level 3 remediation plan to be completed by the end of 2025. Maintain compliance with asset inspections regulations by performing scheduled inspections. Transition to new enterprise-wide GIS mobile application for asset inspections. Implement robust quality assurance/quality control program for asset inspections. Once developed, implement RBDM when scheduling asset inspections in high-risk areas. Integrate GIS and SAP data into an asset management system within the next three years.	Continue to remain in compliance with asset inspection regulations and utilize technological innovations (LiDAR) that will enhance or improve existing inspection practices. Fully integrate a wildfire risk-based asset management inspection program. Continue utilization and improvement of risk modeling to assist with planning of inspection activities. Continue to explore any technological upgrades over its planned asset management structure post-2024.
Vegetation Management and Inspections	Liberty's VM Program has experienced significant growth since filing its first WMP and has been dedicated to program development to accommodate the increasing workload. The next three years will involve refinement of newly developed processes. Liberty will continuously seek out innovations to	Liberty's mission over the next 10 years is to accomplish operational excellence in achieving wildfire mitigation objectives, superior vegetation related reliability and safety metrics, and maintaining regulatory compliance. This mission will be accomplished while demonstrating value beyond regulatory compliance and resource protection to promote sustainable programming

WMP Category	Three Years (2021-2023)	Ten Years (2021-2030)
	improve vegetation inspections and maintenance. Areas of focus to drive improvement include: Evaluating uses cases of remote sensing data and other modern technology • Tree health analysis using multispectral imagery • Prioritization of inspecting trees with strike potential using artificial intelligence • Integration of multiple datasets and applying methods of machine learning to inform risk-based decision-making Providing training and professional development opportunities to employees and contractors to maintain a workforce of highly qualified professionals.	through the application of integrated vegetation management and an emphasis on environmental, social, and governance criteria. Liberty's vision is to be recognized as having a best-in-class utility vegetation management program and will accomplish this by: • Driving continuous improvement through innovation and use of modern technology • Measuring value for maintaining quality of service and benefitting the communities we serve. As the VM Program matures, Liberty will collaborate with other utility vegetation managers to share lessons learned and best practices for vegetation management programming.
Grid Operations and Operating Protocols	Install and/or upgrade reclosers at the rate of three per year. Recloser Distribution Automation ("DA") scheme implementation across the Tahoe Basin; exploring whether to implement outside the Tahoe Basin. Continued improvement to Fire Prevention Plan ("FPP"), Corporate Emergency Management Plan ("CEMP"), and PSPS Playbook. See Attachment H: Liberty's CEMP.	Install and/or upgrade reclosers at the rate of three per year. DA scheme implemented across Liberty's service area, where feasible. Continued improvement to FPP, CEMP, and PSPS Playbook. Explore new innovations with grid operations and fault detections prior to wire down event or customer outage. Research new technologies and collaborate with other utilities.
Data Governance	Standardization of weekly, monthly, quarterly, annual reports. 50% or greater automation of standard reports and live dashboard tracking of initiatives providing measured increases in efficiency and reductions in risk factors.	90% or greater automation of standard reports with live, streamlined dashboard systems.
Resource Allocation Methodology	Continue developing its risk modeling team and capabilities. Liberty is committed to increasing its focus on integrating risk and quantitative analysis into its capital and O&M budgeting process. Liberty project managers will continue to utilize the fire risk map and circuit risk analysis to inform discussions around prioritizing WMP initiative work and will increasingly utilize RSE calculations as a component in overall WMP planning and long-term decision-making.	Liberty anticipates greater technological advancement, as well as the maturity, quality, and robustness of the company's datasets to give more accurate predictive capabilities in its wildfire risk models and RSE calculations.

WMP Category	Three Years (2021-2023)	Ten Years (2021-2030)
Emergency Planning and Preparedness	Continued maintenance of emergency response plans. Continued engagement with local stakeholders to prepare for and respond to fire-related events. Enhanced documentation and use of lessons learned to update plans.	Increased granularity and customization of response plans.
Stakeholder Cooperation and Community Engagement	Implement planned communication channels and technologies with customers, community and stakeholders. Engage Community Based Organizations and expand network of contacts in each area of Liberty service territory, including South Lake Tahoe, North Lake Tahoe, Coleville / Walker, and Loyalton / Portola communities. Work collaboratively with Public Safety Partners and CBO networks to support, educate, notify, and prepare AFN communities. Support bilingual outreach through the utilization of newly added bilingual Outreach Coordinator. Improve overall accessibility of information available to AFN customers. Encourage self-identification of AFN status through targeted outreach efforts and continue to improve internal data systems to support AFN customer identification. Regular PSPS coordination meetings with Tahoe Donner Public Utility District and NV Energy.	Effective stakeholder communication through tailored approaches for outreach, engagement and information exchange with customers, communities and stakeholders based on various groups' unique needs. Identify emerging channels and technologies to better communicate with customers, community and stakeholders. Engage CBOs and further expand network of contacts in each area of Liberty service territory, including South Lake Tahoe, North Lake Tahoe, Coleville / Walker, and Loyalton / Portola communities. Continue to work collaboratively with Public Safety Partners and CBO networks to support, educate, notify, and prepare AFN communities. Continue to support bilingual outreach efforts. Continue to improve overall accessibility of information available to AFN customers based on gathered feedback and effectiveness. Continue to encourage self-identification of AFN status through targeted outreach efforts through assessment of prior year's performance and data. Ongoing PSPS coordination meetings with Tahoe Donner Public Utility District and NV Energy.

5.3. Plan program targets

***Instructions**: Program targets are quantifiable measurements of activity identified in WMPs and subsequent updates used to show progress towards reaching the objectives.*

List and describe all program targets the electrical corporation uses to track utility WMP implementation and utility performance over the last five years. For all program targets, list the 2019 to 2021 performance, a numeric target value that is the projected target for end of year 2022 and 2023, units on the metrics reported, the assumptions that underlie the use of those metrics, update frequency, and how the performance reported could be validated by third parties outside each utility, such as analysts or academic researchers. Identified metrics must be of enough detail and scope to effectively inform the performance (i.e., reduction in ignition probability or wildfire consequence) of each targeted preventive strategy and program.

Pub. Util. Code Section 8386.3(c)(5) requires a utility to notify Energy Safety "after it completes a substantial portion of the vegetation management (VM) requirements in its wildfire mitigation plan." To ensure compliance with this statue, the utility is required to populate Table 5.3- 1 with VM program targets that the utility can determine when it has completed a "substantial portion"[13] and that Energy Safety can subsequently audit. Energy Safety has provided some required, standardized VM targets below. It is expected that the utilities provide additional VM targets beyond those required. The identification of other VM targets and units for those targets (e.g., for inspections, customer outreach, enhanced vegetation management, etc.) are at the discretion of the utility.

Additionally, in Table *5.3- 1, utilities must populate the column "Target%/ Top-Risk%" for each 2022 performance target related to initiatives in the following categories: Grid design and system hardening; Asset management and inspections; and Vegetation management and inspections. This column allows utilities to identify the percentage of the target that will occur in the highest risk areas. For example, if a utility targets conducting 85% of its vegetation management program in the top 20% of its risk-areas, it should input "85/20" in this column. In the "Notes" column, utilities must provide definitions and sources for each of the "Top-Risk%" values provided. In the given example above, an acceptable response would be: "The top 20% of risk areas used for this target relate to the circuit segment risk rankings from [Utility Company's] Wildfire Risk Model outputs, as described in [hyperlink to Section XX] of the 2022 WMP Update."*

Table 5.3- 1: List and Description of Program Targets, last 5 years

Program Target	2019		2020		2021		2022	Units	Audited by Third-Party? (Y/N)
	Target	Perf.	Target	Perf.	Target	Perf.	Target		
Weather stations	-	10	10	19	10	0	10	# of weather stations installed	N
Continuous monitoring sensors	-	-	-	-	10	0	10	# of continuous monitoring sensors installed	N

[13] Energy Safety intends to define "substantial portion" in its forthcoming Compliance Guidelines. This definition may be included in the Final version of the 2022 WMP Update Guidelines.

Program Target	2019		2020		2021		2022	Units	Audited by Third-Party? (Y/N)
	Target	Perf.	Target	Perf.	Target	Perf.	Target		
Fault indicators for detecting faults on electric lines and equipment	-	-	-	-	-	-	2	# of circuits with fault indicators installed	N
Covered conductor	-	2.7	5	6.82	9.1	3.75	9.55	# of circuit miles	N
Distribution pole replacement	-	-	-	62	400	211	231	# of poles replaced	N
Expulsion fuse replacement	-	250	-	853	1,500	867	1,500	# of fuses replaced	N
System automation equipment	-	6	-	4	3	2	4	# of automatic reclosers installed	N
Circuit breaker replacements	1	1	1	1	1	1	1	# of substations with circuit breaker replacements	N
Tree attachments	-	-	-	-	60	37	45	# of tree attachments removed	N
Substation animal guards	-	-	-	-	-	2	4	# of animal guards installed	N
CAL FIRE exempt hardware	-	-	-	-	-	0	TBD	# of CAL FIRE exempt hardware installed	N
Open wire/grey wire	-	-	-	-	-	0	TBD	# of circuit miles	N
Undergrounding of electric lines	-	-	-	-	-	1.03	0.36	# of circuit miles	N
Detailed inspections of distribution electric lines and equipment	-	-	100% of system	100% of system	52	20	308	# of circuit miles inspected	N
Intrusive pole inspections	-	-	-	2,577	3,600	3,506	2,598	# of poles inspected	N
Patrol inspections of distribution electric lines and equipment	20% of system	20% of system	100% of system	100% of system	2,500	2,500	706	# of circuit miles inspected	N
Quality assurance / quality control of inspections	-	-	-	-	-	-	0.5% of detailed inspections	# of circuit miles inspected	Y

Program Target	2019		2020		2021		2022	Units	Audited by Third-Party? (Y/N)
	Target	Perf.	Target	Perf.	Target	Perf.	Target		
Substation inspections	-	-	46	46	46	46	42	# of substations inspected	N
Additional efforts to manage community and environmental impacts	-	-	-	14	13	3.4	9	# of circuit miles	N
Detailed inspections of vegetation around distribution electric lines and equipment	-				207	178	221	# of circuit miles inspected	N
Fuel management and reduction of “slash” from vegetation management activities	-	-	-	376	2,100	2,119	280	Tons of biomass / # of acres[14]	N
LiDAR inspections of vegetation around distribution electric lines and equipment	-	-	-	320	730	701	701	# of circuit miles inspected	N
Patrol inspections of vegetation around distribution electric lines and equipment	-	-			150	179	167	# of circuit miles inspected	N
Quality assurance / quality control of vegetation inspections	-				150	155	220	# of circuit miles	Y
Remediation of at-risk species	-				230	238	238	# of circuit miles	N
Removal and remediation of trees with strike potential to electric lines and equipment	-				150	128	127	# of circuit miles	N
Vegetation management to achieve clearances around electric lines and equipment	-				328	361	701	# of circuit miles	N

[14] Liberty changed the unit of measurement for this initiative from tons of biomass in 2021 to number of acres in 2022.

5.4. Planning for Workforce and Other Limited Resources

***Instructions**: Report on worker qualifications and training practices regarding wildfire and PSPS mitigation for workers in the following target roles:*

1. *Vegetation inspections*
2. *Vegetation management projects*
3. *Asset inspections*
4. *Grid hardening*
5. *Risk event inspection*

For each of the target roles listed above:

1. *List all worker titles relevant to target role (target roles listed above)*
2. *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 the following:*
    a. *Going beyond a basic knowledge of General Order 95 requirements to perform relevant types of inspections or activities in the target role*
    b. *Being a "Qualified Electrical Worker" (QEW) and define what certifications, qualifications, experience, etc. is required to be a QEW for the target role for the utility.*
    c. *Include special certification requirements such as being an International Society of Arboriculture (ISA) Certified Arborist with specialty certification as a Utility Specialist*
3. *Report percentage of Full Time Employees (FTEs) in target role with specific job title*
4. *Provide a summarized report detailing the overall percentage of FTEs with qualifications listed in (2) for each of the target roles.*
5. *Report plans to improve qualifications of workers relevant to wildfire and PSPS mitigation. The utility must explain how they are developing more robust outreach and onboarding training programs for new electric workers to identify hazards that could ignite wildfires.*

5.4.1. Target role: Vegetation inspections

1. Worker titles in target role
2. Minimum qualifications
3. FTE percentages by title in target role
4. Percent of FTEs by high-interest qualification
5. Plans to improve worker qualifications

Table 5.4- 1: Target Role – Vegetation Inspections

1. Worker Titles in Target Role	2. Minimum Qualifications	3. FTE % by title in Target Role	4. % of FTEs by high-interest qualifications
System Arborist (Liberty)	• ISA Arborist Certification or California Registered Professional Foresters License ("RPF") • Four years' experience in Utility Operations with responsibilities in line clearance vegetation management	18%	100%

1. Worker Titles in Target Role	2. Minimum Qualifications	3. FTE % by title in Target Role	4. % of FTEs by high-interest qualifications
Supervisor, Utility Forester (Contractor)	• ISA Arborist Certification • Three to five years utility arboriculture experience	9%	100%
Utility Forester (Contractor)	• Minimum of one year experience in utility arboriculture or related field. Associates degree or greater in urban forestry, forestry, botany, ecology, biology, conservation, environmental science, horticulture or comparable area may substitute for work experience to fulfill the minimum qualifications for this position at the discretion of Liberty's Vegetation Program Manager.	9%	N/A
Utility Forester I (Contractor)	• ISA Arborist Certification or RPF • One year's utility arboriculture experience	18%	100%
Utility Forester II (Contractor)	• ISA Arborist Certification or RPF • ISA Utility Specialist Certification • Three years utility arboriculture experience	27%	100%
Utility Forester III (Contractor)	• ISA Arborist Certification or RPF • ISA Utility Specialist Certification • Five to nine years utility arboriculture experience	18%	100%
Utility Forester IV (Contractor)	• ISA Arborist Certification or RPF • ISA Utility Specialist Certification • 10+ years utility arboriculture experience	N/A	N/A

Minimum Qualifications: Minimum qualifications for worker titles listed in Table 5.4-1 establish personnel that are proficient in providing vegetation inspections, among other duties, to provide regulatory compliance on Liberty's system. Personnel performing vegetation inspections on Liberty's system must demonstrate the required level of competence, gained through technical training, work experience, and professional credentials, set in place by minimum qualifications for each worker title. Liberty's pre-inspection contractors employ their own training programs to provide Liberty with a qualified workforce for its system. The specific skills, training and certificates exhibited by these workers include understanding of regulatory requirements, program policies and procedures, tree identification, knowledge of specific species characteristics and susceptibilities, hazard tree assessments, understanding various types of vegetation threats to electrical equipment, electrical knowledge, fire safety procedures, industry standards and best management practices, and industry safety standards.

Plans to Improve Worker Qualifications: Liberty's internal vegetation management personnel provide monitoring, oversight and evaluation of vegetation inspections to confirm alignment with inspection protocols and to identify opportunities for improvement. Liberty conducts periodic benchmarking with vegetation inspection workers to review tree assessment practices, procedures, scopes of work and inspection requirements to continually align and improve worker qualifications. Liberty conducts monthly status meetings with all vegetation inspection personnel to provide project, program and organizational updates, as well as, continuing education opportunities towards professional credentials. Liberty continually seeks opportunities to improve worker qualifications for vegetation inspections through regular program review and a collaborative approach with its contractor providing vegetation inspection services.

5.4.2. Target role: Vegetation management projects

1. Worker titles in target role
2. Minimum qualifications
3. FTE percentages by title in target role
4. Percent of FTEs by high-interest qualifications
5. Plans to improve worker qualifications

Table 5.4- 2: Target Role – Vegetation Management Projects

1. Worker Titles in Target Role	2. Minimum Qualifications	3. FTE % by title in Target Role	4. % of FTEs by high-interest qualifications
General Foreperson (Contractor)	• Two years' experience as Foreperson • Two years prior experience as Journeyman Tree Trimmer	7%	100%
Foreperson (Contractor)	• One year experience as Journeyman Tree Trimmer	23%	N/A
Journeyman Tree Trimmer (Contractor)	• 18 months of related training and on the job experience • Successful completion of Company Line Clearance Tree Trimmer Certification Program	15%	N/A
Trimmer Trainee (Contractor)	• Successful completion of Grounds Operation Specialist Test	27%	N/A
Bucket Operator (Contractor)	• Prior experience as professional Tree Trimmer or Climber • Meets Journeyman Tree Trimmer requirements	See Foreperson, Journeyman Tree Trimmer, and Trimmer Trainee	N/A

1. Worker Titles in Target Role	2. Minimum Qualifications	3. FTE % by title in Target Role	4. % of FTEs by high-interest qualifications
Groundperson (Contractor)	N/A	27% (can be a specific ground crew or made up of members of tree crew)	N/A

Minimum Qualifications: Minimum qualifications for worker titles listed in Table 5.4-2 certify that personnel are proficient in providing the work required for vegetation management projects along Liberty's system. Personnel performing tree work for vegetation management projects must demonstrate the required level of competence, gained through technical training and work experience, set in place by minimum qualifications for each worker title. Liberty's line-clearance tree contractors employ their own training programs and establish minimum qualifications to provide a qualified workforce for Liberty's system. The specific skills, training and certificates exhibited by these workers include understanding of regulatory requirements, program policies and procedures, tree identification, knowledge of specific species characteristics and susceptibilities, hazard tree assessments, understanding various types of vegetation threats to electrical equipment, electrical knowledge, fire safety procedures, industry standards and best management practices, and industry safety standards.

Plans to Improve Worker Qualifications: Liberty's internal vegetation management personnel provide monitoring, oversight and evaluation of vegetation management projects to confirm project goals and objectives are met and to identify opportunities for improvement. Regular project tailboards, field meetings and work verification is conducted with General Forepersons and crew members to communicate goals, progress, and opportunities. Liberty continually strives for long-term program efficiency and sustainability through vegetation project management and collaboration with its line-clearance tree contractors performing project work on the system.

5.4.3. Target role: Asset inspections

1. Worker titles in target role
2. Minimum qualifications
3. FTE percentages by title in target role
4. Percent of FTEs by high-interest qualifications
5. Plans to improve worker qualifications

Table 5.4- 3: Target Role – Asset Inspections

1. Worker Titles in Target Role	2. Minimum Qualifications	3. FTE % by title in Target Role	4. % of FTEs by high-interest qualifications
Inspector	• Journeyman lineman; • Minimum one year journeyman lineman experience; • Class A Driver's License; • General knowledge of G.O. 95 and company's construction standards.	83.3%	N/A

1. Worker Titles in Target Role	2. Minimum Qualifications	3. FTE % by title in Target Role	4. % of FTEs by high-interest qualifications
Inspector Foreman	• Journeyman lineman; • Minimum two years journeyman lineman experience; • CDL required; • Expert knowledge of G.O. 95 and company's construction standards.	16.7%	N/A

5.4.4. Target role: Grid hardening

1. Worker titles in target role
2. Minimum qualifications
3. FTE percentages by title in target role
4. Percent of FTEs by high-interest qualifications
5. Plans to improve worker qualifications

Table 5.4- 4: Target Role – Grid Hardening

1. Worker Titles in Target Role	2. Minimum Qualifications	3. FTE % by title in Target Role	4. % of FTEs by high-interest qualifications
Engineer IV	• Must possess a Bachelor of Science in Electrical Engineering or an equivalent engineering degree from an accredited four-year college or university. • Must hold PE certification.	6.5%	N/A
Capital Administrator	• Associates or Bachelor's degree in Construction Administration, Accounting or a related field or a minimum of three years of technical experience with a utility or other related field. • Working knowledge of accounting, project management and construction management practices.	3.2%	N/A
Project Manager	• Associates or Bachelors degree in Project Management, Construction Administration, Engineering in a related field or a PMP certification and a minimum of five years of technical experience with a	6.5%	N/A

1. Worker Titles in Target Role	2. Minimum Qualifications	3. FTE % by title in Target Role	4. % of FTEs by high-interest qualifications
	utility or other related field. Must have a demonstrated working knowledge of project management and construction management practices.		
Lineman	• Journeyman lineman. • Class C Driver's license	38.7%	N/A
Lineman Working Foreman	• Journeyman lineman. • Minimum two years' experience as Journeyman Lineman. • Class C Driver's license	12.9%	N/A
Inspector	• Journeyman lineman. • Minimum one year journeyman lineman experience. • Class A Driver's License. • General knowledge of G.O. 95 and company's construction standards.	16.1%	N/A
Inspector Foreman	• Journeyman lineman. • Minimum two years journeyman lineman experience. • Class A Driver's License. • Expert knowledge of G.O. 95 and company's construction standards.	3.2%	N/A
Substation Electrician	• Must have successfully completed the Electrician Apprentice training program or equivalent. • Must be qualified to perform switching.	3.2%	N/A
Substation Electrician Working Foreman	• Journeyman Electrician. • Minimum two years' experience as journeyman electrician. • Must be qualified to perform switching.	3.2%	N/A
Job Facilitator	• Journeyman lineman. • Minimum two years' experience as journeyman lineman. • Class C Driver's License.	6.5%	N/A

<u>Plans to Improve Worker Qualifications</u>: By adding qualified professionals Liberty will be able to train and raise the skill set of the existing work force. Training plans are in progress for all engineering team members for 2022 and beyond.

5.4.5. Target role: Risk event inspections

1. Worker titles in target role
2. Minimum qualifications
3. FTE percentages by title in target role
4. Percent of FTEs by high-interest qualifications
5. Plans to improve worker qualifications

Table 5.4- 5: Target Role – Risk Event Inspections

1. Worker Titles in Target Role	2. Minimum Qualifications	3. FTE % by title in Target Role	4. % of FTEs by high-interest qualifications
Troubleshooter	• Journeyman lineman. • Minimum one year experience as journeyman lineman	100%	N/A

6. PERFORMANCE METRICS AND UNDERLYING DATA

Instructions*: Section to be populated from Quarterly Reports. Tables to be populated are listed below for reference.*

NOTE: Report updates to projected metrics that are now actuals (e.g., projected 2021 spend will be replaced with actual unless otherwise noted). If an actual is substantially different from the projected (>10% difference), highlight the corresponding metric in light green.

6.1. Recent performance on progress metrics, last 7 years

Instructions for Table 1 of Attachment 3*: In the attached spreadsheet document, report performance on the following metrics within the utility's service territory over the past seven years as needed to correct previously reported data. Where the utility does not collect its own data on a given metric, each utility is required to work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in the "Comments" column.*

Table 1: Recent Performance on Progress Metrics, last 7 years is provided in Attachment A.

6.2. Recent performance on outcome metrics, annual, last 7 years

Instructions for Table 2 of Attachment 3*: In the attached spreadsheet document, report performance on the following metrics within the utility's service territory over the past seven years as needed to correct previously reported data. Risk events and utility-related ignitions are normalized by wind warning status (RFW & HWW). Where the utility does not collect its own data on a given metric, the utility is required to work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in "Comments" column.*

Provide a list of all types of findings and number of findings per type, in total and in number of findings per circuit mile.

Table 2: Recent Performance on Progress Metrics, last 7 years is provided in Attachment A.

6.3. Description of additional metrics

Instructions for Table 3 of Attachment 3: *In addition to the metrics specified above, list and describe all other metrics the utility uses to evaluate wildfire mitigation performance, the utility's performance on those metrics over the last seven years, the units reported, the assumptions that underlie the use of those metrics, and how the performance reported could be validated by third parties outside the utility, such as analysts or academic researchers. Identified metrics must be of enough detail and scope to effectively inform the performance (i.e., reduction in ignition probability or wildfire consequence) of each preventive strategy and program.*

Table 3: List and Description of Additional Metrics, last 7 years is provided in Attachment A.

6.4. Detailed information supporting outcome metrics

Instructions for Table 4 of Attachment 3: *In the attached spreadsheet document, report numbers of fatalities attributed to any utility wildfire mitigation initiatives, as listed in the utility's previous or current WMP filings or otherwise, according to the type of activity in column one, and by the victim's relationship to the utility (i.e., full-time employee, contractor, of member of the general public), for each of the last five years as needed to correct previously reported data.*

For fatalities caused by initiatives beyond these categories, add rows to specify accordingly. The relationship to the utility statuses of full-time employee, contractor, and member of public are mutually exclusive, such that no individual can be counted in more than one category, nor can any individual fatality be attributed to more than one initiative.

Table 4: Fatalities due to utility wildfire mitigation initiatives, last 7 years is provided in Attachment A.

Instructions for Table 5 of Attachment 3*: In the attached spreadsheet document, report numbers of OSHA-reportable injuries attributed to any utility wildfire mitigation initiatives, as listed in the utility's previous or current WMP filings or otherwise, according to the type of activity in column one, and by the victim's relationship to the utility (i.e., full-time employee, contractor, of member of the general public), for each of the last seven years as needed to correct previously reported data. For members of the public, all injuries that meet OSHA-reportable standards of severity (i.e., injury or illness resulting in loss of consciousness or requiring medical treatment beyond first aid) must be included, even if those incidents are not reported to OSHA due to the identity of the victims.*

For OSHA-reportable injuries caused by initiatives beyond these categories, add rows to specify accordingly. The victim identities listed are mutually exclusive, such that no individual victim can be counted as more than one identity, nor can any individual OSHA-reportable injury be attributed to more than one activity.

Table 5: OSHA-reportable Injuries due to Utility Wildfire Mitigation Initiatives, last 7 years is provided in Attachment A.

6.5. Mapping recent, modelled, and baseline conditions

Instructions: *The utility must provide underlying data for recent conditions (over the last five years) of the utility's service territory in a downloadable shapefile GIS format, following the spatial reporting schema.[15] All data is reported quarterly, this is a placeholder for quarterly spatial data.*

Refer to Liberty's Quarter 1 2022 Quarterly Data Report submitted on May 2, 2022.

6.6. Recent weather patterns, last 7 years

Instructions for Table 6 of Attachment 3*: In the attached spreadsheet document, report weather measurements based upon the duration and scope of NWS Red Flag Warnings, High wind warnings and upon proprietary Fire Potential Index (or other similar fire risk potential measure if used) for each year. Calculate and report 5-year historical average as needed to correct previously reported data.*

Table 6 of Attachment 3: Weather patterns, last 7 years – reference only, fill out attached spreadsheet to correct prior reports

Table 6: Weather Patterns, last seven years is provided in Attachment A.

6.7. Recent and projected drivers of outages and ignition probability

Instructions for 7.1 and Table 7.2 of Attachment 3: *(Table 7.1) In the attached spreadsheet document, report recent drivers of outages according to whether or not risk events of that type are tracked, the number of incidents per year (e.g., all instances of animal contact regardless of whether they caused an outage, an ignition, or neither), the rate at which those incidents (e.g., object contact, equipment failure, etc.) cause an ignition in the column, and the number of ignitions that those incidents caused by category, for each of last seven years as needed to correct previously-reported data. Calculate*

[15] https://energysafety.ca.gov/wp-content/uploads/energy-safety-gis-data-reporting-standard_version2.1_09072021_final.pdf.

and include 5-year historical averages. This requirement applies to all utilities, not only those required to submit annual ignition data. Any utility that does not have complete 2021 ignition data compiled by the WMP deadline is required to indicate in the 2021 columns that said information is incomplete. (Table 7.2) Similar to Table 7.1, but for ignition probability by line type and HFTD status, according to if ignitions are tracked.

Table 7.1: Key Recent and Projected Drivers of Ignition Probability, last seven years and projections is provided in Attachment A.

Table 7.2: Key Recent and Projected Drivers of Ignition Probability by HFTD Status, last seven years and projections is provided in Attachment A.

6.8. Baseline state of equipment and wildfire and PSPS event risk reduction plans

6.8.1. Current baseline state of service territory and utility equipment

Instructions for Table 8 of Attachment 3: *In the attached spreadsheet document, provide summary data for the current baseline state of HFTD and non-HFTD service territory in terms of circuit miles; overhead transmission lines, overhead distribution lines, substations, weather stations, and critical facilities located within the territory; and customers by type, located in urban versus rural versus highly rural areas and including the subset within the Wildland-Urban Interface (WUI) as needed to correct previously reported data.*

The totals of the cells for each category of information (e.g., "circuit miles (including WUI and non-WUI)") would be equal to the overall service territory total (e.g., total circuit miles). For example, the total of number of customers in urban, rural, and highly rural areas of HFTD plus those in urban, rural, and highly rural areas of non-HFTD would equal the total number of customers of the entire service territory.

Table 8: State of Service Territory and Utility Equipment is provided in Attachment A.

6.8.2. Additions, removal, and upgrade of utility equipment by end of 3-year plan term

Instructions for Table 9 of Attachment 3: *In the attached spreadsheet document, input summary information of plans and actuals for additions or removals of utility equipment as needed to correct previously reported data. Report net additions using positive numbers and net removals and undergrounding using negative numbers for circuit miles and numbers of substations. Report changes planned or actualized for that year – for example, if 10 net overhead circuit miles are added in 2020, then report "10" for 2020. If 20 net overhead circuit miles are planned for addition by 2022, with 15 being added by 2021 and 5 more added by 2022, then report "15" for 2022 and "5" for 2021. Do not report cumulative change across years. In this case, do not report "20" for 2022, but instead the number planned to be added for just that year, which is "5".*

Table 9: Location of Actual and Planned Utility Equipment Additions or Removal Year Over Year is provided in Attachment A.

Instructions for Table 10 of Attachment 3: *Referring to the program targets discussed above, report plans and actuals for hardening upgrades in detail in the attached spreadsheet document. Report in terms of number of circuit miles or stations to be upgraded for each year, assuming complete implementation of wildfire mitigation activities, for HFTD and non-HFTD service territory for circuit miles of overhead transmission lines, circuit miles of overhead distribution lines, circuit miles of overhead transmission lines located in Wildland-Urban Interface (WUI), circuit miles of overhead distribution lines in WUI, number of substations, number of substations in WUI, number of weather stations and number of weather stations in WUI* *as needed to correct previously-reported data. If updating previously reported data, separately include a list of the hardening initiatives included in the calculations for the table.*

Table 10: Location of Actual and Planned Utility Infrastructure Upgrades Year Over Year is provided in Attachment A.

7. MITIGATION INITIATIVES

7.1. Wildfire Mitigation Strategy

***Instructions**: Describe organization-wide wildfire mitigation strategy and goals for each of the following time periods, highlighting changes since the prior WMP:*

1. *By June 1 of current year*
2. *By Sept 1 of current year*
3. *Before the next Annual WMP Update*
4. *Within the next 3 years*
5. *Within the next 10 years*

Liberty's near-term goals, by June 1 of 2022, by September 1, 2022, and before the next Annual WMP Update, are provided in Table 7.1- 1. Longer-term goals for the three-year and 10-year timeframes are discussed in Section 5.2: The Objectives of the Plan. Wildfire mitigation strategy is further discussed in Section 7.3: Detailed Wildfire Mitigation Programs.

Table 7.1- 1: Liberty's Near-Term Strategy and Goals by WMP Category

WMP Category	By June 1, 2022	By September 1, 2022	Before 2023 WMP Update
Risk Assessment & Mapping	Use Reax wildfire risk segmented polygons as the basis for updating Liberty's circuit risk assessment and for wildfire mitigation planning. Analyze asset risk, tree risk, outage risk, and risk reduction from WMP initiative implementation. Continue to participate in Joint IOU Wildfire Risk Modeling Working Group.	Continue to analyze asset risk, tree risk, outage risk, and risk reduction from WMP initiative implementation. Continue to participate in Joint IOU Wildfire Risk Modeling Working Group.	Continue to improve Liberty's wildfire risk modeling capabilities. Continue to participate in Joint IOU Wildfire Risk Modeling Working Group.
Situational Awareness	Work with ALERTWildfire, adopting eight wildfire cameras. Distribution Fault Anticipation ("DFA") site locations selected and ready for deployment.	Install 10 additional weather stations and incorporate into weather monitoring network. Deploy 10 DFA units. Deploy fault indicators in Tier 3 region as a pilot.	Determine gaps in camera network coverage and evaluate need for additional camera installations. Identify potential site locations for weather stations. Develop more advanced use cases for fault indicators. Continue to evaluate FPI and weather monitoring systems for improvements.

MITIGATION INITIATIVES

WMP Category	By June 1, 2022	By September 1, 2022	Before 2023 WMP Update
Grid Design and System Hardening	Complete 0.5 miles of covered conductor, 75 pole replacements, 300 fuse replacements, and 15 tree attachment removals. Replace second Oil Circuit Breaker ("OCB") at Tahoe City substation. Portola substation rebuild design at 100%. Squaw Valley sub breaker replacements design at 90%.	Complete five miles of covered conductor, 150 pole replacements, 900 fuse replacements, and 30 tree attachment removals.	Complete 9.55 miles of covered conductor, 231 pole replacements, 1,500 fuse replacements, and 45 tree attachment removals. Complete five OCB replacements at Tahoe City and Squaw Valley substations. Portola design at 100% and ready for construction in Fall 2022.
Asset Management and Inspections	Complete 25% of scheduled asset inspections. Continue to develop and improve the processes around digital based inspections that were introduced in 2020 to support inspection activities.	Complete 25%-75% of scheduled asset inspections. Begin development of RFP scope and parameters for infrared and quality assurance pilot programs	Finish the remaining 25% of scheduled asset inspections scheduled for 2022. Finalize RFPs for infrared asset inspections and quality assurance pilot programs to put out to bid.
Vegetation Management and Inspections	Complete 289 miles of vegetation inspections. Complete 775 miles of vegetation maintenance.	Complete 1,163 miles of vegetation inspections. Complete 1,015 miles of vegetation maintenance.	Complete 1,322 miles of vegetation inspections. Complete 1,116 miles of vegetation maintenance.
Grid Operations and Operating Protocols	Continue installing new line reclosers to better sectionalize and have relaying devices closer to end-of-line to help detect low current faults. Liberty is planning to install one additional line recloser by June 1, 2022. Finalize Liberty's PSPS Playbook and review with operations teams prior to fire season.	Explore fault detection with communications to more quickly determine the location of a fault when using fast trips to mitigate a PSPS situation.	Install four additional line reclosers in 2022 and replace or install at least three line reclosers per year going forward. Continue to explore fault detection with communications to more quickly determine the location of the fault when using fast trips to mitigate a PSPS situation.
Data Governance	Integration of additional data tools to facilitate standardization, including Liberty's new GIS enterprise system launched in April 2022.	Continue additional integration of data tools to facilitate standardization.	Standardize monthly, quarterly and annual WMP reports.

MITIGATION INITIATIVES

WMP Category	By June 1, 2022	By September 1, 2022	Before 2023 WMP Update
Resource Allocation Methodology	Liberty project managers will utilize the updated fire risk map and circuit risk analysis to inform discussions regarding prioritizing WMP initiative work. Continue to refine RSE data inputs and calculations. Initiate planning and design on major capital projects to be completed in 2023.	Liberty project managers will utilize the updated fire risk map and circuit risk analysis to inform discussions regarding prioritizing WMP initiative work. Continue to refine RSE data inputs and calculations and update existing RSE calculations.	Liberty project managers will utilize the updated fire risk map and circuit risk analysis to inform discussions regarding prioritizing WMP initiative work. Continue to refine RSE data inputs and calculations and update existing RSE calculations and include additional RSE calculations for WMP initiatives. Initiate planning and design on major capital projects to be completed in 2024.
Emergency Planning and Preparedness	Conduct Incident Command ("IC") training for all identified IC members and hold a virtual PSPS tabletop exercise.	Meet with Community Advisory Boards.	Continue engagement with local stakeholders to prepare for and respond to fire-related events. Continue implementation of Liberty's 2022 AFN Plan. Continue maintenance of emergency response plans. Enhance documentation and use of lessons learned to update plans.
Stakeholder Cooperation and Community Engagement	Promote PSPS, wildfire, and readiness messaging through CBO partnerships, social media, email, and digital channels. Continue identification of AFN and medical baseline customers, including enhanced communication channels and utilizing programs and services to identify AFN customers. Expand opportunities to extend and amplify messaging through CBOs and other support groups. Complete virtual town halls and PSPS exercise, including gathering feedback. Complete pre-fire season customer and CBO surveys on wildfire and PSPS awareness.	Enhance communication channels and utilize programs and services to identify AFN customers. Complete post-fire season customer and CBO surveys on wildfire and PSPS awareness.	Continue to survey customers, CBOs, community partners and stakeholders to understand wildfire and PSPS awareness and customer needs. Strengthen and expand partnerships with CBOs that support AFN communities. Identify emerging channels and technologies to better communicate with customers, community and stakeholders.

***Instructions**: The description of utility wildfire mitigation strategy must:*

A. Discuss the utility's approach to determining how to manage wildfire risk (in terms of ignition probability and estimated wildfire consequence) as distinct from managing risks to safety and/or reliability. Describe how this determination is made both for (1) the types of activities needed and (2) the extent of those activities needed to mitigate these two different groups of risks. Describe to what degree the activities needed to manage wildfire risk may be incremental to those needed to address safety and/or reliability risks.

Liberty's approach to determining wildfire risk versus safety and/or reliability is discussed in Section 4.2. The underlying approach is use of the fire risk polygon designations of low, moderate, high, and very high as the basis for prioritizing wildfire mitigation initiatives. The "Very High" and "High" fire risk areas are the primary focus of Liberty's wildfire mitigation planned work efforts presented in this plan. Below are some examples for prioritizing wildfire mitigation efforts.

Table 7.1- 2: Liberty WMP Activity Prioritization

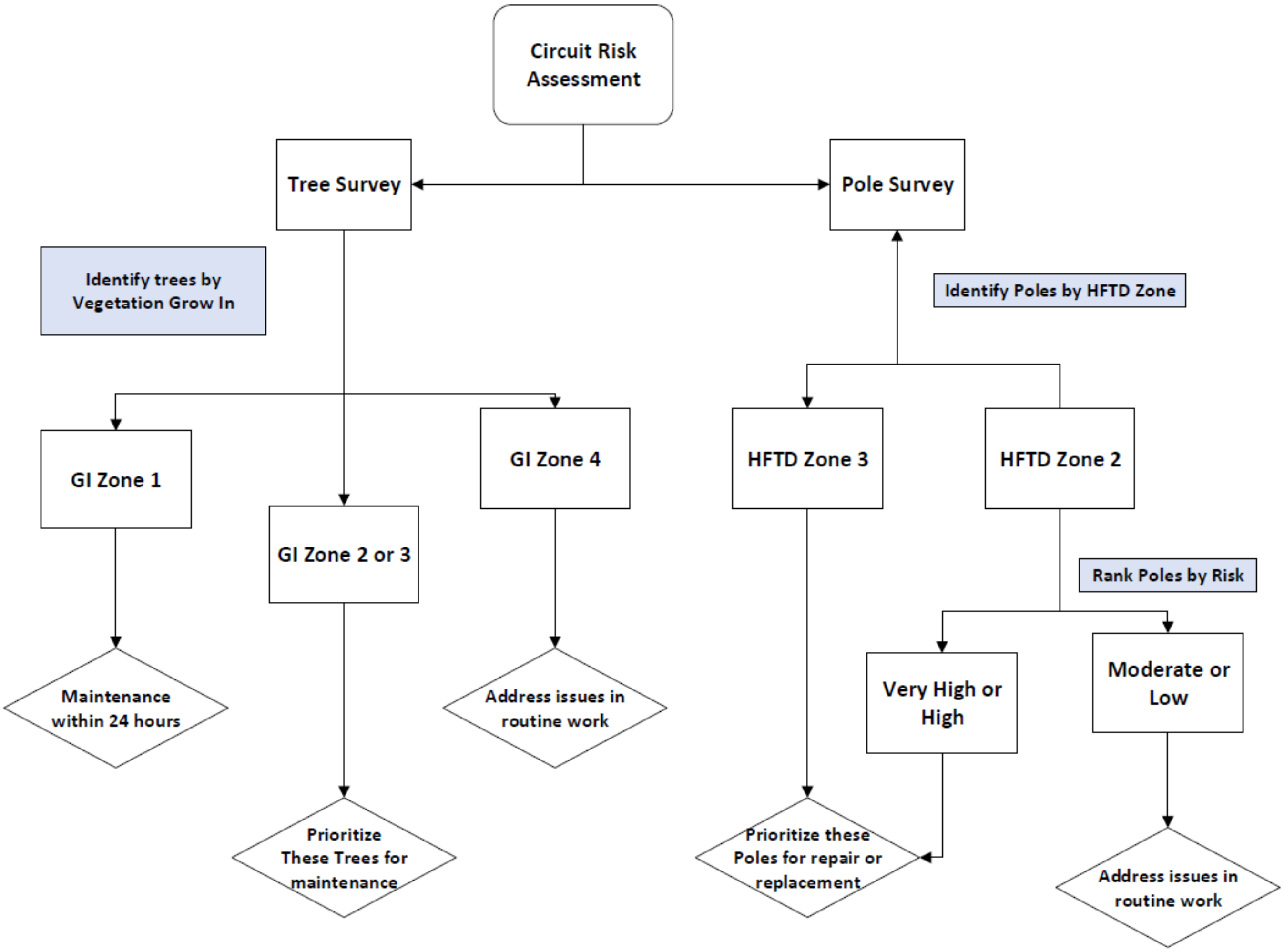
WMP Activity	Wildfire Risk	Safety/Reliability Risk	Wildfire Mitigation Priority
Vegetation Management	Low	High	Varies
Vegetation Management	Moderate	High	Varies
Vegetation Management	High	High	High
Asset Repairs	High	Moderate	High
Asset Repairs	Very High	Low	Moderate
Asset Repairs	Very High	Moderate	High
Asset Repairs	High	Moderate	High

B. Discuss how risk modeling outcomes are used to inform decision-making processes and used to prioritize mitigation activities. Provide detailed descriptions including clear evaluation criteria[16] and visual aids (such as flow charts or decision trees). Provide an appendix (including use of relevant visual aids) with specific examples demonstrating how risk modeling outcomes are used in prioritizing circuit segments and selecting mitigation measures.

Liberty provided an example of how risk modeling outcomes were used to prioritize mitigations on the Meyers 3400 circuit in Section 4.3. Liberty factors in various risk types – asset risk, tree risk, and wildfire risk in its determination of overall circuit risk. See Attachment J for Liberty's circuit risk assessment.

[16] "Evaluation criteria" should include all points of considerations including any thresholds and weights that may affect the outcome of their decision, as well as a descriptor of how it is evaluated (*i.e.*, given a risk score, using SME expertise to determine that score, using a formula).

Figure 7.1- 1: Flow Chart for Circuit Risk Determination and Prioritizing WMP Work



Additionally, Liberty recognizes the importance of risk-spend efficiency ("RSE") calculations and calculated RSEs related to multiple WMP initiatives in 2021 (provided in Attachment E). Liberty will continue to improve and refine its RSE calculations and actively participate in Joint IOU workshops and discussions on the RSE metric. Liberty utilizes its RSE calculations as one component in overall WMP planning and long-term decision-making. Liberty is in the process of updating calculations to refine its estimated effectiveness percentages using information gathered from risk modeling and other working group discussions and will provide updated RSE calculations to OEIS when available.

C. Include a summary of achievements of major investments and implementation of wildfire mitigation initiatives over the past year, lessons learned, changed circumstances during the 2020-2022 WMP plan cycle, and corresponding adjustment in priorities for the current year. Organize summaries of initiatives by the wildfire mitigation categories listed in Section 7.3.

A summary of achievements, lessons learned, and implementation of wildfire mitigation initiatives over the past year is provided in Table 4. 1. Program metrics (planned and actual) by wildfire mitigation categories are provided in Section 5.3: Plan Program Targets.

D. List and describe all challenges associated with limited resources and how these challenges are expected to evolve over the next 3 years.

One of the challenges of operating a utility in the Lake Tahoe area is a lack of qualified staff in the region. Lake Tahoe is a resort community with many residences serving as second homes. Affordable housing is in limited supply for potential employees. More affordable housing is located over an hour away, and access to Liberty's service territory is sometimes challenging via mountain roads that are periodically shut down due to winter weather. These challenges make it more difficult for Liberty to be a competitive employer for positions, such as degreed/licensed engineers and project managers.

Liberty plans to add resources in order to bolster modeling capability and accuracy of utility overall risk modeling, specifically wildfire risk modeling. To date, Liberty has leveraged the technical risk management proficiency of internal analysts and formed a team of consultants with guidance from Liberty's corporate Energy Risk Management team.

E. Outline how the utility expects new technologies and innovations to impact the utility's strategy and implementation approach over the next 3 years, including the utility's program for integrating new technologies into the utility's grid. Include utility research listed above in Section 4.4.

LiDAR: Liberty strives for continuous improvement by using technologies and other tools with the potential to enhance the quality and efficiency of its vegetation management inspections. In 2020, Liberty piloted LiDAR inspections of vegetation around electric lines and equipment in approximately half of its service territory, including all line miles in the Extreme (Tier 3) High Fire Threat District. The pilot project proved to be successful in detecting vegetation to conductor clearance issues, and Liberty expanded the use of LiDAR, beginning in 2021, to include annual inspections of 100% of its overhead electric lines and equipment.

Tripsavers: Liberty continues to use S&C Tripsavers as a non-expulsion alternative to traditional fuses on feeder laterals. Tripsavers reduce ignition potential due to fuse operations and allow for greater flexibility in coordination of protective devices, leading to shorter customer interruptions. Some Tripsavers are set to be deployed with SCADA, which can be a cost-efficient alternative to recloser installations. Costs of S&C Tripsavers are captured under the expulsion fuse replacement program.

Sagehen microgrid: Liberty successfully commissioned and constructed an innovative microgrid solution to a remote mountain research station. This project has saved customers over $2 million by replacing a high fire-risk distribution line with a containerized solar plus battery storage microgrid. The project is a wildfire mitigation solution that avoided costly replacement of four miles of distribution line serving a single customer in Central Sierra Nevada, north of Truckee, California. The microgrid allows Liberty to completely de-energize the line in the summer, maintaining reliable service to the customer.

Distribution Fault Anticipation: DFA is a collaborative project between Texas A&M and Liberty. The technology is an incipient fault detection technology that detects small anomalies in the AC power waveform due to events such as arcing hardware or tree branches in the line that are non-permanent faults. Per the CPUC's suggestion, Liberty selected DFA as a possible technology during development of the 2021 WMP. Other IOUs are piloting incipient fault technologies, which appear to help find and stop ignitions before they happen.

High Impedance Fault Detection: HIFD is a collaborative research project between the University of Nevada, Reno and Liberty. This technology detects faults that are high impedance in nature. It is believed that this technology will work particularly well in the Lake Tahoe Basin considering the poor grounding conditions in the area. Liberty selected HIFD for its ability to clear high impedance faults. With the poor grounding in much of Liberty's territory, this technology is intended to clear faults rapidly before ignitions. Traditional protection measures have not performed well with these types of faults on poorly grounded networks.

Ground Fault Neutralization ("GFN"): GFN is an established technology developed by Swedish Neutral. Widely used in Europe and Australia, this technology drives line-to-ground fault current to near zero, significantly decreasing risk of ignition. Swedish Neutral claims that this technology works well on a three-wire system, such as Liberty's 14.4kV three-wire system. Liberty is considering GFN for its ability to drive line-to-ground fault current to near zero. If it performs as intended, GFN will greatly limit the available energy required to ignite vegetation.

Advanced Metering Infrastructure ("AMI"): AMI's project scope includes installing advanced two-way metering technology and infrastructure throughout Liberty's service territory. AMI data will provide Liberty with granular system demand data for all customer classes, which is a big improvement over Liberty's current ability to track only system demands for larger and medium commercial customers (customers with interval demand meters). AMI data will offer Liberty more precise data measurements when evaluating segmented effects of lost service, aid in predicting future consequences with voluminous real-time data, and help restore customers in the event of a PSPS. AMI data is projected to be available in 2023. AMI will enhance public safety with Outage Management System ("OMS") integration and remote switching capabilities, which can be used during PSPS events.

Liberty's Customer First Platform: Liberty's implementation of its Customer First initiative will feature the enterprise resource planning software SAP, which will integrate with Liberty's updated ESRI GIS system to improve Liberty's asset management capabilities. SAP is expected to be in service in 2023. Currently, Liberty has a limited asset management framework that tracks outage type and number, vegetation issues, inspection issues, line miles, number of assets in high risk areas, and SAIDI/SAIFI/CAIDI statistics by circuit. The Enterprise Asset Management ("EAM") and Asset Manager SAP applications will help Liberty mitigate the risk of wildfire ignitions. EAM will provide more integrated processes for managing equipment conditions and predicting equipment failures before they occur, allowing Liberty to proactively replace aging equipment before it fails in service. EAM and Asset Manager will also improve wildfire mitigation documentation and reporting for both internal and external stakeholders.

F. *Provide a GIS layer[17] showing wildfire risk (e.g., MAVF); data should be as granular as possible.*

The GIS file with this information was submitted to OEIS on May 2, 2022 as part of Liberty's 2022 Quarter One Reporting.

G. *Provide GIS layers[18] for the following grid hardening initiatives: covered conductor installation;[19] undergrounding of electrical lines and/or equipment; and removal of electrical lines. Features must have the following attributes: state of hardening, type of hardening where known (i.e., undergrounding, covered conductors, or removal), and expected completion date. Provide as much detail as possible (circuit segment, circuit-level, etc.). The layers must include the following:*
   - *a. Hardening planned for 2022*
   - *b. Hardening planned for 2023*
   - *c. Hardening planned for 2024*

The GIS file with this information was submitted to OEIS on May 5, 2022.

H. *Provide static (either in text or in an appendix), high-level maps of the areas where the utility will be prioritizing Grid Design and System Harding initiatives for 2022, 2023, and by 2032.*

See Attachment C: Maps of Liberty Covered Conductor, Pole Replacement and Fuse Replacement Projects

[17] GIS data that has corresponding feature classes in the most current version of Energy Safety GIS Data Reporting Standard will utilize the format for submission. GIS data that does not have corresponding feature classes shall be submitted in an ESRI compliant GDB and include a data dictionary as part of the metadata.

[18] Energy Safety acknowledges potential security concerns regarding aggregating and presenting critical electrical infrastructure in map form. Utilities may provide maps or GIS layers required by these Guidelines as confidential attachments when necessary.

[19] For a definition of "covered conductor installation" see Section 9 of Attachment 2.

I. *Provide a GIS layer for planned Asset Management and Inspections in 2022. Features must include the following attributes: type, timing, and prioritization of asset inspection. Inspection types must follow the same types described in Section 7.3.4, Asset Management and Inspections, and as applicable, should not be limited to patrols and detailed inspections.*

The GIS file with this information was submitted to OEIS on May 2, 2022 as part of Liberty's 2022 Quarter One Reporting.

J. *Provide a GIS layer illustrating where enhanced clearances (12 feet or more) were achieved in 2020 and 2021, and where the utility plans to achieve enhanced clearances in 2022. Feature attributes must include clearance distance greater than or equal to 12 feet, if such data is available, either in ranges or as discrete integers (e.g., 12-15 feet, 15-20 feet, etc. OR 12, 13, 14, 15, etc.).*

The GIS file with this information was submitted to OEIS on May 2, 2022 as part of Liberty's 2022 Quarter One Reporting.

7.2. Wildfire Mitigation Plan implementation

***Instructions**: Describe the processes and procedures the electrical corporation will use to do all the following:*

A. *Monitor and audit the implementation of the plan. Include what is being audited, who conducts the audits, what type of data is being collected, and how the data undergoes quality assurance and quality control.*

Liberty's implementation of WMP initiatives is monitored through the OEIS Quarterly Initiative Update ("QIU"), Quarterly Data Report ("QDR"), GIS data schema submissions, and annual WMP Update filling. Additionally, WMP activities at Liberty and related data are audited by external regulatory agencies such as the CPUC. Liberty's data submissions undergo QA/QC reviews by multiple internal business units and data related to Liberty's inspection programs undergoes QA/QC through established formal programs. Components of Liberty's emergency response WMP initiatives are reviewed and approved annually by the CPUC.

B. *Identify any deficiencies in the plan or the plan's implementation and correct those deficiencies.*

Liberty continually looks for opportunities to enhance and refine its WMP. Liberty addresses the WSD-identified deficiencies with its 2021 WMP in Section 4.6.

C. *Monitor and audit the effectiveness of inspections, including inspections performed by contractors, carried out under the plan and other applicable statutes and commission rules.*

Liberty's QA/QC programs monitor and audit the effectiveness of its Vegetation Management and Asset Management inspection programs. For Vegetation Management, Liberty implements and maintains a robust scheduling process in order to meet compliance inspection requirements. Most of the maintenance work for vegetation management (pre-inspection, pruning, and tree removals) is performed by contractors and not by Liberty employees. On an annual basis, over 10,000 trees are identified for work, and there is a need to track work performed and associated business processes and to have a standardized QA/QC program. For Asset Management inspection programs, Liberty developed an inspection auditing program in 2021 and is implementing the program in 2022. A qualified contractor will be selected in order to validate that Liberty is conducting inspections in an effective manner in compliance with the G.O. 165 inspection process and G.O. 95 construction standards. Additionally, operation managers will be spot-auditing new construction.

D. *Ensure that across audits, initiatives, monitoring, and identifying deficiencies, the utility will report in a format that matches across WMPs, Quarterly Reports, Quarterly Advice Letters,[20] and annual compliance assessment.*

Liberty's overall goal is to develop an integrated data management and reporting solution to improve data consistency and efficiencies internally and for the WMP reporting process. Liberty has made significant efforts to respond to the OEIS quarterly reporting requirements. Liberty recognizes the need for a single standardized system for streamlined and consistent reporting across the WMP, quarterly reports, quarterly advice letters, annual compliance assessment, and all other WMP-related requests.

Liberty has three major software upgrades underway that will impact reporting, including upgrades to its Geographic Information System ("GIS"), Outage Management System ("OMS"), and Responder databases. In designing a solution that considers these major system upgrades and integrates with all current data sources, Liberty has initiated conversations and requests for information with consultants offering data analytics solutions. Liberty is expanding its technical staffing, training, and wider IT involvement to help manage continuous process improvement while balancing the use of external resources.

7.3. Detailed wildfire mitigation initiatives

Instructions*: In this section, describe how specific wildfire and PSPS mitigation initiatives execute the strategy set out in Section 5. The initiatives are divided into 10 categories, with each providing a space for narrative descriptions of the utility's initiatives. The initiatives are organized by the following categories provided in this section:*

1. *Risk assessment and mapping*
2. *Situational awareness and forecasting*
3. *Grid design and system hardening*
4. *Asset management and inspections*
5. *Vegetation management and inspections*
6. *Grid operations and protocols*
7. *Data governance*
8. *Resource allocation methodology*
9. *Emergency planning and preparedness*
10. *Stakeholder cooperation and community engagement*

It is not necessary for a utility to have every initiative listed under each category.

Financial data on mitigation initiatives

Instructions*: Report actual and projected WMP expenditure, as well as the risk-spend-efficiency (RSE), for each initiative by HFTD tier (territory-wide, non-HFTD, HFTD zone 1, HFTD tier 2, HFTD tier 3) in Table 12 of Attachment 3.*

Table 12: Mitigation Initiative Financials is provided in Attachment A.

[20] General Rule for filing Advice Letters are available in General Order 96-B: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M023/K381/23381302.PDF

MITIGATION INITIATIVES

Detailed information on mitigation initiatives

***Instructions**: Report detailed information for each initiative. For each initiative, organize details under the following headings:*

1. ***Risk to be mitigated** / problem to be addressed*
2. ***Initiative selection** ("why" engage in activity) – include reference to and description of a risk informed analysis and/or risk model on empirical (or projected) impact of initiative in comparison to alternatives and demonstrate that outcomes of risk model are being prioritized*
3. ***Region prioritization** ("where" to engage activity) – include reference to a risk informed analysis in allocation of initiative (e.g., veg clearance is done for trees tagged as "high-risk") and demonstrate that high-risk areas are being prioritized*
4. ***Progress on initiative** since the last WMP submission and plans, targets, and/or goals for the current year*
5. ***Future improvements to initiative** – include known future plans (beyond the current year) and new/novel strategies the utility may implement in the next 5 years (e.g., references to and strategies from pilot projects and research detailed in Section 4.4).*

***List of initiative activities by category** – Detailed definitions for each mitigation activity are provided in the appendix.*

7.3.1. Risk Assessment and Mapping

7.3.1.1. A summarized risk map that shows the overall ignition probability and estimated wildfire consequence along the electric lines and equipment

1. Risk to be mitigated

This initiative will increase Liberty's awareness of all wildfire risk drivers. Through its wildfire risk mapping, Liberty identifies wildfire risk drivers and the impacts of potential fires of consequence that could occur in its service territory.

2. Initiative selection

This initiative supports various wildfire mitigation efforts by providing better information to make risk-informed decisions.

3. Region prioritization

Liberty's wildfire risk map was developed for the entire service territory.

4. Progress on initiative

In 2021, Liberty worked with Reax Engineering to update its fire risk study, including:

- Calculating outage rates (frequency) per overhead line mile/density, temperature and wind speed (outage time) to determine the likelihood of outages given historic weather data. A major finding was that wind speeds had a tighter correlation to historic outages than temperature changes.
- Using outage rates from step 1, overhead line density, humidity, fuel bed moisture levels and temperature to determine the probability of ignition for each plotted outage to calculate ignition rates.
- Creating a heat map of the ignition rates (and outage rates) along Liberty's circuits that operations, planning, and engineering teams can use to plan future mitigation efforts. High ignition rate areas are generally found in windy and drier areas.
- Layering on historic hourly weather data, fuel and topography layers, and circuit ignition rates to simulate millions of ignitions along Liberty's overhead lines to project wildfire spread over a 24-hour period. Wildfire

consequences are tallied by average and worst -case scenarios by circuit and shows the number of structures lost, acres burned, and timbers lost.

- Utilizing Reax's new fire ignition and fire propagation model results in wildfire risk polygons that are ranked Very High, High, Moderate, and Low. Notable risk profile increases (moderate to high) from the original fire risk polygons are Walker, Topaz and Coleville, South of Fallen Leaf, Olympic Valley, and Alpine Meadows.

In 2022, Liberty plans to:

- Use Reax wildfire risk polygons as the basis for updating its circuit risk assessment and for wildfire mitigation planning.
- Continue to analyze asset risk, tree risk and outage risk and risk reduction from WMP initiative implementation.

5. Future improvements to initiative

Liberty plans to enhance its wildfire risk assessment processes and capabilities through the continued incorporation of updated and more granular data inputs.

7.3.1.2. Climate-driven risk map and modeling based on various relevant weather scenarios

Refer to Section 4.2.1, Section 4.5.1.1 and Section 7.3.1.1.

7.3.1.3. Ignition probability mapping showing the probability of ignition along the electric lines and equipment

Refer to Section 7.3.1.1.

7.3.1.4. Initiative mapping and estimation of wildfire and PSPS risk-reduction impact

Refer to Section 7.3.1.1.

7.3.1.5. Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment

See Section 7.3.1.1.

7.3.2. Situational Awareness

7.3.2.1. Advanced weather monitoring and weather stations

1. Risk to be mitigated

Liberty's advanced weather monitoring program improves situational awareness by providing weather information to operations and allows for the safe operation of the electric grid during extreme weather events. Certain weather events can cause damage to the electrical system, which leads to the possibility of an ignition event. Real-time weather monitoring data provides an important tool to help Liberty plan for operating activities during such extreme events.

2. Initiative selection

This initiative is necessary to provide the weather data required to accurately predict wildfire risk in Liberty's service territory. An alternative to installing Liberty-owned weather stations is to use data provided by existing weather stations in or near Liberty's service territory, but these weather stations do not provide the frequency or quantity of data required for Liberty's PSPS and Fire Potential Index ("FPI") programs.

3. Region prioritization

The expansion of this program will focus on areas where risk mapping initiatives have determined high or very high fire risk or where more granular weather data can provide for better sectionalizing options during a PSPS.

4. Progress on initiative

Since 2019, Liberty has installed 29 weather stations equipped with fuel moisture sensors across its service territory. The weather station network was utilized in 2021 and provides valuable weather monitoring and situational awareness information for operational decision-making. Liberty plans to install 10 additional weather stations in 2022 that will expand coverage throughout Liberty's service territory and will prioritize installations based on high fire risk areas and areas where gaps in weather station coverage exist along power lines.

5. Future improvements to initiative

Weather stations will be added in future years on a case-by-case basis, as needed, to support more granular sectionalizing of circuits during PSPS events.

7.3.2.2. Continuous monitoring sensors

1. Risk to be mitigated

Distribution Fault Anticipation ("DFA"): DFA technology is designed to detect incipient faults. These small faults may not be significant enough to cause power outages, but the recurrence of these faults in the same location can lead to full failure and risk of ignition.

High Impedance Fault Detection ("HIFD"): HIFD technology is designed to detect faults that are high impedance in nature.

ALERTWildfire Cameras: Mountain top cameras are a situational awareness tool that can assist with early detection of ignitions, determining the location of the fire, and the rate and direction of which the fire is spreading. Early detection of fire is critical for fire suppression and response.

2. Initiative selection

DFA: DFA is a collaborative project between Texas A&M and Liberty. The technology is an incipient fault detection technology that detects small anomalies in the AC power waveform due to events such as arcing hardware or tree branches in the line that are non-permanent faults. Fault data can be detected remotely and can be used to locate a fault providing better opportunity to dispatch crews more quickly to the fault location. Other IOUs are piloting incipient fault technologies, which appear to help find and stop ignitions before they occur.

HIFD: HIFD is a collaborative research project between the University of Nevada, Reno and Liberty. This technology is designed to detect faults that are high impedance in nature. It is believed that this technology will work particularly well in the Lake Tahoe Basin due to the poor grounding conditions in the area. Liberty selected HIFD for its ability to clear high impedance faults. With the poor grounding in much of Liberty's territory, this technology may clear faults rapidly before ignitions. Traditional protection measures have not performed well with these types of faults on poorly grounded networks.

ALERTWildfire Cameras: The ALERTWildfire Camera network has grown significantly throughout California and other western states in large part due to collaborations with electric utilities. Over the last few years, these cameras have become an integral part of fire detection and monitoring during fire season in California. With more cameras, improving technology, and more partnerships, the capabilities of the ALERTWildfire network will continue to improve on an already successful platform.

3. Region prioritization

Region prioritization or DFA and HIFD will be focused primarily in the Tier 3 region, moving out to Tier 2 if the technology is shown to reduce wildfire ignition risk. For the ALERTWildfire Camera program, Liberty has partnered with University of Nevada, Reno and the ALERTWildfire fire camera network. The partnership brings Liberty's adoption of eight fire cameras in the Lake Tahoe basin as well as the ability to access other existing cameras within Liberty's service territory.

4. Progress on initiative

DFA: DFA hardware has been purchased and received and is expected to be installed on 105 distribution feeders by the end of 2022, and the remaining 5 units will be installed in 2023. HIFD is set to be deployed in 20212. For GFN, Liberty is in the beginning stages of launching a GFN pilot program at Meyers (Tier 3) Substation, with a goal for a 2022 in-service date.

HIFD: After delays in the project timeline, HIFD is set to be deployed in 2022. The HIFD settings produced by University of Nevada Reno will be installed into the protection relays feeding our piloted lines. Liberty will set these to alarm on a HIF and subsequently inspect.

ALERTWildfire Cameras: Liberty's partnership for eight fire cameras will be finalized in the second quarter of 2022, which will provide access to the camera network prior to 2022 fire season.

5. Future improvements to initiative

DFA: Once the 10 DFA units are deployed, Liberty will begin collecting fault data and evaluating the information for effectiveness. Texas A&M DFA research continues and algorithms are improved over time, which should lead to even greater effectiveness of DFA data. Liberty plans to deploy more units in future years if the technology aids in ignition prevention in Liberty's service territory.

HIFD: For selected lines, Liberty will evaluate whether high impedance faults are detected more quickly.

ALERTWildfire Cameras: High-definition camera technology continues to evolve as artificial intelligence capabilities are introduced for automated early detection of fire. Liberty will work with vendors with new technologies to use cameras for automated detection of ignitions.

7.3.2.3. Fault indicators for detecting faults on electric lines and equipment

1. Risk to be mitigated

During summer months, Liberty experiences faults along numerous distribution feeders. In order to clear these faults, linemen must patrol the long expanses of territory and manually locate where the fault occurred. Depending on the environmental conditions and length feeders, this effort can be time-consuming.

2. Initiative selection

In efforts to mitigate wildfire risk and increase system reliability, a pilot program will be implemented in select high fire risk zones in Liberty's territory using both remotely-communicated and 360-degree visual indicating fault indicators. A remotely-communicated fault indicator will allow system control to dispatch lineman directly to the fault locations, and visual indicating fault indicators will assist lineman in locating faults where remote communications are not viable. This ultimately would allow for faults to be more easily detected, located and cleared to reduce wildfire risk, outages, and damaged equipment.

3. Region prioritization

Liberty plans to install fault indicators on circuits that experience a high frequency of faults and lateral lines that cross through Tier 3 HFTD zones.

4. Progress on initiative

Based on the region prioritization outlined above, Tier 3 HFTD circuits have been identified in the Meyers district, and Liberty is getting quotes from vendors to procure the fault indicators in 2022. Liberty targets two circuits in 2022 for fault indicators.

5. Future improvements to initiative

At the end of 2022, Liberty will assess the pilot project and, based on the results, consider adding more units in 2023.

7.3.2.4. Forecast of a fire risk index, fire potential index, or similar

1. Risk to be mitigated

Liberty's FPI is a comprehensive assessment tool designed to heighten awareness of daily forecast fire conditions to aid in operational decision-making. FPI converts environmental, statistical, and scientific data into an easily understood forecast of short-term fire threat for Liberty's service territory. FPI forecasts up to seven days of fire threat potential. More details regarding FPI can be found in Section 4.5.1.3.

2. Initiative selection

Liberty uses FPI for fire threat awareness and operational decision-making. FPI provides a seven-day fire risk condition forecast for 11 geographic zones within the service territory. FPI condition forecasts include five risk conditions (Low, Moderate, High, Very High, and Extreme) that are used to determine operating procedures, by zone, depending on the forecast fire risk. FPI condition forecasts are communicated to field staff daily to inform operational decisions when work restrictions are in place due to fire risk. Prior to the development of FPI, Liberty did not have any specialized fire risk prediction tools, which meant less overall awareness of day-to-day fire risk.

3. Region prioritization

There are 11 FPI zones covering Liberty's service territory with individual fire risk forecasts for each zone. This forecasting granularity provides a better understanding of the overall fire risk throughout Liberty's service territory and allows for better for better decision-making in scheduling work by zone.

4. Progress on initiative

FPI Methodology Development: FPI was developed for Liberty's service territory based on the methodologies of San Diego Gas & Electric ("SDG&E") and Pacific Gas & Electric Company ("PG&E"). Factors considered include climatological, geographical, and fuel source conifer and timber understory fuels in Liberty's service territory. FPI calculations include fuel moisture (both dead and live), "green-up" factor, ambient temperature, relative humidity, Fosberg fire weather index, burning index, among other factors. This work led to the establishment of the number of FPI classes as well as the fuel and weather criteria that delineate FPI classes.

Identification of FPI zones/polygons: Eleven FPI zones have been developed to capture homogeneous fuels, weather, and topography within each zone. The number of zones and their extent encompass Liberty's service territory.

Establishment of FPI thresholds for each FPI zone based on historical weather analyses: Historical data was analyzed to establish appropriate FPI thresholds specific to the areas identified above. FPI values for determining allowable work and operations based on fire risk were delineated based on weather station observations and the state of fuels, including seasonal variations in fuel moisture and short-term fire weather conditions (temperature, wind speed, relative humidity/vapor pressure deficit, etc.).

Extend proactive de-energization monitoring and operational support tool to include FPI calculation: Liberty has developed a web-based monitoring and operational support tool that displays FPI values by zones, in addition to PSPS weather analytics and forecasting.

5. Future improvements to initiative

With FPI brought online, Liberty continues to monitor forecast accuracy and reliability. Through the monitoring process, Liberty and Reax Engineering will identify inconsistencies between forecast and monitored conditions in order to make improvements in forecast accuracy.

7.3.2.5. Personnel monitoring areas of electric lines and equipment in elevated fire risk conditions

1. Risk to be mitigated

In areas with elevated fire weather condition forecasts, Liberty will activate proactive patrols along power lines. Operations personnel will be deployed to observe conditions along the electrical system (vegetation issues, equipment condition, wire sag and sway, and any potential system damage related to the weather event) that may pose a threat to public safety. This added situational awareness provides the ability to identify imminent safety risks in order to resolve them immediately.

2. Initiative selection

Liberty engages in this initiative because it provides a beneficial supplement to other situational awareness activities. Liberty monitors real-time conditions through its weather station network and fire weather tools and can deploy field resources to evaluate and resolve issues to mitigate fire risk during elevated fire weather conditions.

3. Region prioritization

Liberty monitors forecast and real-time weather conditions by utilizing weather station data and fire weather prediction tools. FPI and PSPS zones, which receive individualized forecasts, help to determine the specific circuits that are predicted to experience elevated fire risk conditions. This knowledge allows for patrol resources to be more accurately and efficiently deployed.

4. Progress on initiative

In the last two years, Liberty has worked with Reax Engineering to develop the FPI and PSPS forecasting tools. These forecasting tools have been foundational in developing the methodology for the deployment of resources during elevated fire risk events. See Section 4.5.1.3 for more details on FPI and Chapter 8 for PSPS protocols. Costs associated with this initiative are captured in Section 7.3.6.4 of the Grid Operations and Protocols category.

5. Future improvements to initiative

Liberty will continue to evaluate its proactive patrol methodology by incorporating lessons learned from field personnel and weather forecasting analysis. As weather monitoring and fire forecasting tools evolve, Liberty hopes to improve its ability to deploy resources as efficiently and accurately as possible.

7.3.2.6. Weather forecasting and estimating impacts on electric lines and equipment

Refer to Section 7.3.2.4.

7.3.3. Grid Design and System Hardening

7.3.3.1. Capacitor maintenance and replacement program

Liberty does not currently have a capacitor maintenance and replacement WMP initiative. Capacitors are inspected during G.O. 165 inspections.

7.3.3.2. Circuit breaker maintenance and installation to de-energize lines upon detecting a fault

1. Risk to be mitigated

Installing new circuit breakers mitigates the risk of energy release component during fault conditions by decreasing the fault clearing times and energy release component during a system fault. Breakers are being updated and installed as part of Liberty's overall WMP objective to rebuild its aging substations, allowing for increased fault clearing times, greatly improving switching speeds, and reducing energy release component.

2. Initiative selection

Brockway Substation, an aging substation located in a residential area, was decommissioned and replaced by installing new circuit breakers at Kings Beach Substation. Liberty is focused on replacing oil circuit breakers ("OCB") rather than trying to maintain them. Liberty removed OCBs from Meyers (2019), Kings Beach (2020), Tahoe City (2021), Squaw Valley (2022), and Stateline (2023-24) substations.

3. Region prioritization

Liberty is evaluating other regions and selecting substation circuit breaker replacements based on risk assessment and current equipment capability.

4. Progress on initiative

Circuit breaker replacements were completed at the Tahoe City Substation in 2021. Squaw Valley will be completed in 2022. The Stateline substation rebuild project, scheduled in 2023 and 2024, will also replace 2 OCBs with new circuit breakers.

5. Future improvements to initiative

Future improvements for this initiative include adding personnel to support capital project delivery and engineering leadership.

7.3.3.3. Covered conductor installation

1. Risk to be mitigated

Installing covered conductor mitigates the risk of faults due to line impact, animals, and line-to-line faults. Covered conductor is effective at mitigating several types of ignition drivers such as contact from object and wire-to-wire contact, as well as reducing other equipment failures. Refer to Attachment B: Joint IOU Covered Conductor Effectiveness Report.

2. Initiative selection

Liberty's service territory, located in the High Sierras of California, is prone to wildfire risk. Additionally, the Lake Tahoe area accommodates a massive influx of visitors during peak tourism season, which happens to coincide with peak fire season. Liberty selected covered conductor as a system hardening initiative to reduce the risk of wildfire in an area with limited resources (roads, infrastructure, emergency response, and ingress/egress) to handle the capacity of tourists. Liberty selected to perform work in this initiative with its pilot Aerial Cable Systems ("ACS") and tree wire covered conductor program in areas based on climate, reliability, and asset conditions.

3. Region prioritization

A vast majority of Liberty's service territory is in HFTD 2 and 3 areas. In the initial phases (2020 and 2021) of the covered conductor program, areas of the service territory were selected based on local knowledge of the wildland/urban interface, locations of high fire threat districts, and the age and condition of the current infrastructure. Areas were also chosen based on their accessibility and egress options during an emergency. Initiatives in 2020 and 2021 were focused mainly on the southwest shores of Lake Tahoe and Fallen Leaf Lake in South Lake Tahoe. These areas already needed line upgrades and are in high-traffic areas with limited options for egress, especially in peak tourism season. Since the deployment of Liberty's risk-based assessment, covered conductor projects selected for 2022 and beyond are chosen based on the areas providing the greatest risk reduction gained by implementing covered conductor projects.

4. Progress on initiative

In 2020 and 2021, Liberty completed the following covered conductor projects:

Table 7.3.3- 1: Liberty 2020-2021 Covered Conductor Projects

Project Name	Year	Design Type	Total Spend	Number of Poles	Mileage	Tree Removals/Trims
7300 Phase 3a	2020	ACS	$1,151,297	12	0.5	28 removals; 14 trims
7300 Phase 3b	2020	ACS	$971,938	13	0.45	
7300 Phase 4	2020	ACS	$926,732	21	0.75	18 removals; 35 trims
7300 Phase 5	2020	ACS	$971,938	20	0.7	11 removals; 27 trims
Vikingsholm	2020	ACS	$1,716,578	26	1.25	44.25 removals; 93 trims (.25 units refer to brush)
Topaz Phase 2	2020	Tree Wire	$591,752	13	0.47	0
Topaz Phase 4	2020	Tree Wire	$1,155,133	41	1.8	24 removals; 3 trims
Topaz Phase 5	2020	Tree Wire	$1,050,650	39	0.9	
3300 Bridge Tract	2021	ACS	$2,618,383	24	0.9	21 removals, 94 trims
Lily Lake	2021	ACS	$3,923,812	51	2.0	23 removals, 80 trims
7300 Ph6	2021	Tree Wire	$1,795,679	27	0.85	250.47 removals, 113.25 trims
Echo Summit	2021	Tree Wire	$1,200,000	15	0.45	348 removals
TOTAL	**2020-2021**		**$18,073,893**	**302**	**11.02**	

In 2022 and 2023, Liberty plans the following covered conductor projects:

Table 7.3.3- 2: Liberty 2022 Covered Conductor Planned Projects

Project Name	Design Type	Total Budgeted	Number of Poles	Mileage
Brockway 4202 Resiliency	ACS	$1,158,172	16	0.50
Cathedral Park A	ACS	$2,000,000	39	1.41
Cathedral Park B	ACS	$2,500,000	57	2.17
3400 Cascade	Tree Wire	$1,100,000	8	0.23
Hobart 7700	ACS	$4,000,000	84	3.08
Topaz Ph6	Tree Wire	$1,532,540	56	1.53
Fallen Leaf A	Tree Wire	$1,236,000	25	0.66
TOTAL		**$13,526,712**	**285**	**9.55**

Table 7.3.3- 3: Liberty 2023 Covered Conductor Planned Projects

Project Name	Design Type	Total Budgeted	Number of Poles	Mileage
Celio A	Tree Wire	$1,946,230	46	1.61
Celio B	Tree Wire	$2,150,000	25	0.93
Fallen Leaf B	ACS	$1,338,530	51	1.53
7300 Ph7	ACS	$2,084,840	29	0,68
7300 Ph8	ACS	$2,300,000	33	0.90
TOTAL		**$9,819,600**	**184**	**5.65**

Liberty is replacing overhead lines with covered conductor to protect high fire risk areas and to improve system reliability. Liberty's project scope and design for covered conductor projects includes replacing and installing new overhead assets, including new crossarms, lightning arrestors, fuses, and other hardware. In addition, the vegetation management group inspects the proposed line installation route and conducts tree work as needed for proper clearance. For 2022 and 2023, Liberty is installing the covered conductor projects listed in the previous tables.

The Brockway 4202 circuit project will install covered conductor on a section of the circuit out of the Kings Beach Substation. The project has three main objectives: (1) to harden the system in high priority areas to mitigate wildfire risks; (2) to reduce outage times and increase reliability along the circuit; and (3) to provide a resiliency corridor to provide power to key customers in the area from the Kings Beach generators in the event of an outage in the area.

The Meyers 3400 circuit covered conductor projects are part of a large-scale, multi-part project involving replacement of aged assets with the installation of covered conductor. The project has two main objectives: (1) to harden the system in high priority areas to mitigate wildfire risks and (2) to reduce outage times and increase reliability along the circuit. The terrain of much of this circuit area is remote and characterized by massive, expansive hard-rock fields, making pole hole digging a very labor-intensive operation. In addition, the circuit has a lot of exposure during storm events, which results in outages due to high winds and fallen trees. Most of the work will be conducted by hand crews and helicopters due to the remote terrain. Meyers 3400 projects include Cathedral Park A, Cathedral Park B, Cascade, Fallen Leaf A, and Fallen Leaf B.

The Meyers 3300 circuit covered conductor projects are part of a large-scale, multi-part project, involving replacement of aged assets with the installation of covered conductor. The project has two main objectives: (1) to harden the system in high priority areas to mitigate wildfire risks and (2) to reduce outage times and increase reliability along the circuit. The terrain of much of this circuit area is remote and characterized by massive, expansive boulder fields, making pole hole digging a very labor-intensive operation. In addition, the circuit has a lot of exposure during storm events, which results in outages due to high winds and fallen trees. Most of the work will be conducted by hand crews and helicopters due to the remote terrain. Meyers 3300 projects include Celio A and Celio B.

The Hobart 7700 circuit covered conductor project is a large-scale project with two main objectives: (1) to harden the system in high priority areas to mitigate wildfire risks and (2) to reduce outage times and increase reliability along the circuit. This area of Liberty's system was identified as a high-risk fire area and deemed a priority for hardening the system in this location. The project primarily focuses on reducing the fire risk along the Hobart 7700 line and increasing the reliability of the feeder in the Hobart area and includes the replacement of 84 poles and the installation of just over three miles of new covered tree wire.

The Topaz 1261 circuit covered conductor project is a large-scale project with two main objectives: (1) to harden the system in high priority areas to mitigate wildfire risks and (2) to reduce outage times and increase reliability along the circuit. The circuit is in a Tier 2 HFTD area that is subject to high winds, which necessitates system hardening to adhere to wildfire mitigation plan efforts being pursued by Liberty.

The Tahoe City 7300 circuit covered conductor project is a large-scale, multi-part project. The project has three main objectives: (1) to harden the system in high priority areas to mitigate wildfire risks, (2) to reduce outage times and increase reliability along the circuit, and (3) to increase capacity to be able to meet demands along the circuit from either the north or south, as needed, during outages. The circuit routes approximately 15 miles along the west shore of Lake Tahoe. Due to its length, the circuit has a lot of exposure during storm events which results in outages due to high winds and falling trees. The Tahoe City 7300 projects include the 7300 Phase 7 and 7300 Phase 8 projects.

5. Future improvements to initiative

Liberty is still in the early stages of implementing covered conductor projects and developing its methodology and process for the use of covered conductor. A key assumption that Liberty has made, based on industry research and subject matter expert opinions, is that covered conductor along with associated equipment replacement is a cost-effective way to mitigate the potential for the electric distribution system to cause a wildfire and to improve reliability by replacing aging infrastructure. To determine the top priority projects for installation of covered conductor, Liberty evaluates outage and potential ignition history, risk analysis, infrastructure age, and reliability considerations. Because most of Liberty's service territory is located in either HFTD 3 or HFTD 2 heavily forested territory, covered conductor is considered for all primary distribution replacement.

Liberty uses both tree wire covered conductor and ACS bundled covered conductor. Although there have been some changes in the decision-making process for when to use each type of covered conductor, the current practice is to use ACS bundled covered conductor in areas where there is bucket truck access to the majority of the line. In inaccessible areas, tree wire is typically used. The primary considerations for using this decision process is failure restoration time and linemen safety. In some cases, projects are being designed with ACS bundled covered conductor with small sections of tree wire in inaccessible areas. Liberty intends to continue to refine its decision-making process regarding when to use each type of covered conductor.

Additionally, to supplement the covered conductor initiative, Liberty is conducting microgrid feasibility studies in areas of its service territory where a microgrid may be a cost-effective alternative. In some cases, microgrids may allow for the removal of an unreliable distribution line rather than having to replace the line. A microgrid may also allow for a line to be shut off during fire season without impacting customer reliability to reduce fire risk. Microgrids may also reduce impacts from PSPS events. The Angora Ridge Covered Conductor Project is a project where a microgrid has been preliminarily determined to be a cost-effective alternative. In this case, the covered conductor project has been put on hold while the microgrid project is further developed. Upon verification that the project is feasible and cost-effective, Liberty will construct with a potential completion in 2023.

7.3.3.4. Covered conductor maintenance

Liberty does not currently have a separate covered conductor maintenance WMP initiative. Liberty intends to include areas where covered conductor is installed in its asset inspection program that includes annual patrol inspections and detailed inspections on the timing set forth in G.O. 165. Liberty also intends to closely monitor the performance of covered conductor, both to verify the effectiveness of covered conductor for wildfire mitigation and to determine if any special maintenance is required.

7.3.3.5. Crossarm maintenance, repair, and replacement

Liberty does not currently have a crossarm maintenance WMP initiative. Lines are patrolled and inspected as part of G.O. 165 inspections.

7.3.3.6. Distribution pole replacement and reinforcement, including with composite poles

1. Risk to be mitigated

Pole replacements and reinforcements minimize the risk of system fault due to structural pole failure.

2. Initiative selection

During the system-wide survey that Liberty completed in 2020, inspections were performed on all of Liberty's 22,400 poles. Inspectors identified poles requiring replacement based on G.O. 95 conditions Levels 1, 2 or 3. Every pole requiring replacement was assigned a due date based on the condition of the pole and its location. Level 1 poles in HFTD 3 areas were replaced immediately. Level 2 poles in HFTD 3 areas and Level 1 poles in HFTD 2 areas were also replaced within six months of inspection. In 2021, 169 Level 2 poles in HFTD 2 areas were replaced, and the remaining 231 Level 2 poles will be replaced in 2022. Liberty also replaces poles as a result of its Intrusive Pole Inspection Program. Poles that fail intrusive testing are scheduled for replacement. Testing of poles and replacement of failed poles are completed based on the timing set forth in G.O. 165.

3. Region prioritization

Liberty prioritized pole replacements based on Liberty's fire risk maps. Poles requiring replacement in HFTD 3 areas have been replaced, and Liberty is now focusing on replacing poles in HFTD 2 areas

4. Progress on initiative

Liberty has completed 211 pole replacements for this initiative. Liberty did not meet its 2021 target for this initiative because the Tamarack and Caldor fires impacted line construction resources, and supply chain issues impacted the timing of material availability. All pole replacement designs were completed in 2021. As part of the 211 pole replacements in this initiative, Liberty replaced 169 poles identified as G.O. 165 Level 2 replacements in the system-wide survey that Liberty completed in 2020. In addition to the pole replacements completed within this initiative, Liberty also replaced approximately 175 poles resulting from fire or storm damage in 2021, which impacted available resources. Line crew contracts and material orders are in place to complete the remaining Level 2 poles in 2022. Liberty will start pole replacements as the snow melts and construction can continue.

5. Future improvements to initiative

Liberty continues to refine its data collection process for its pole inspections and the associated replacements or repairs. Recently, detailed inspections have been collected with a GIS-based digital collection process. The data is then analyzed, and replacements and repairs are tracked in the same system. This change has improved the coordination and documentation of the inspection process and associate corrective actions.

Liberty has tried intumescent wrapped poles and ductile-iron poles. Further study is planned to determine if alternative pole types such as these are appropriate cost-effective solutions for various situations

7.3.3.7. Expulsion fuse replacement

1. Risk to be mitigated

The goal of the expulsion fuse replacement program is to mitigate ignition potential of traditional expulsion fuses by replacing them with non-expulsion alternatives. When a fault occurs on the distribution system, the fault is often isolated by an expulsion fuse, which, upon operation, discharges gas and particles that could ignite nearby vegetation. By replacing traditional fuses with non-expulsion fuses, the ignition potential is significantly reduced.

2. Initiative selection

The expulsion fuse replacement initiative installs CAL FIRE-approved non-expulsion fuse hardware, which has shown reduced ignition potential compared to traditional fusing alternatives. Since Liberty began replacing expulsion fuses in 2019, there have been no ignitions resulting from non-expulsion fuses. Although the dataset is small, initial results indicate that non-expulsion fuses are effective at mitigating ignition potential due to fuse operations.

3. Region prioritization

The expulsion fuse replacement program is prioritized utilizing Liberty's fire risk maps, prioritizing areas identified with higher wildfire risk. Refer to Attachment C for a map of fuse replacement locations along with Liberty risk areas.

4. Progress on initiative

In 2021, Liberty replaced 867 expulsion fuses out of its target of 1,500. The primary reasons Liberty missed its 2021 target were supply chain issues impacting material availability and prohibitive lead times for procuring adequate materials. The Tamarack and Caldor fire responses also impacted Liberty's resources for this initiative.

5. Future improvements to initiative

Liberty has resolved supply chain issues by expanding its pool of suppliers and plans to maintain its target of 1,500 fuses per year until the approximately 9,000 fuses in Liberty's HFTD Tier 2 and Tier 3 areas are replaced.

7.3.3.8. Grid topology improvements to mitigate or reduce PSPS events

In February 2022, Liberty filed an application at the CPUC for a Customer Resiliency Program intended to provide customers with greater energy resiliency during PSPS and other hazardous events. Refer to Attachment B for additional information regarding Liberty's Customer Resiliency Program.

1. Risk to be mitigated

Liberty's proposed Customer Resiliency Program provides customer energy resiliency benefits intended to serve Liberty customers in anticipation of increasing hazardous events across Liberty's territory, including wildfire, PSPS, and winter storm events. By providing essential energy resiliency benefits to customers, the Resiliency Portfolio will improve the reliability and resiliency of Liberty electric service and safety for customers.

2. Initiative selection

Liberty identified the need for customer resiliency offerings, driven by wildfire, PSPS, and winter storm outage events. Liberty conducted a Stakeholder Engagement Survey in 2020 to assess general customer interest and limitations regarding energy storage as a possible resiliency solution. Customers responded favorably, and Liberty initiated the process to develop a Resiliency Portfolio. While customer resiliency benefits are Liberty's primary motivation for the Program, Liberty may also deliver financial benefits to all customers through demand savings in its long-term Energy Services Agreement with NV Energy.

To inform its Portfolio, Liberty reviewed resiliency program and project models considered and implemented by other U.S. utilities. Liberty identified well-founded models to incorporate within its own design considerations, including Pacific Gas & Electric Company's (PG&E) Community Microgrid Enablement Program, which has been approved by the CPUC, and the Northern States Power's (Xcel Energy's) Resiliency Service Pilot, approved by the Wisconsin Public Service Commission. Liberty developed a high-level Portfolio design concept, identifying target customers, outage durations to be addressed, and potential delivery models.

3. Region prioritization

Liberty developed a framework to assess resiliency needs in its territory and applied this framework to identify regional corridors with the highest resiliency benefits. Liberty considered hazards, disruption challenges, penetration of critical customers, and social impacts in various regions of its service territory. Liberty identified the Kings Beach region as an initial target for resiliency services and a resiliency corridor demonstration project, with other regions to be considered for future development. Additionally, Liberty's Customer Resiliency Program will offer behind-the-meter ("BTM") energy storage systems and resiliency services to MBL customers and critical facilities across Liberty's service territory.

4. Progress on initiative

As the foundation of the Customer Resiliency Program, Phase 1 will deliver a total potential of 55 MWh of energy storage available to support resiliency for up to 173 customers. The program is proposed to run for three years, during which participating customers will enroll and receive installed Battery Energy Storage Systems ("BESS") in their homes, businesses, and facilities. Participating customers will make Resiliency-as-a-Service ("RaaS") payments that will be added to their bills over the 10-year life of the BESS asset, during which customers will receive benefits and Liberty will own, manage, and maintain the systems. The RaaS model defers and distributes over time the upfront capital and ongoing operational costs to customers. RaaS payments and offerings have also been designed to meet the needs and limitations of each eligible customer type, including highly subsidized offerings for medical baseline customers. Critical facilities and large commercial customers' RaaS payments will reflect the BESS sized for their individual needs.

Additionally, in Phase 1, Liberty proposes a Kings Beach microgrid resiliency corridor demonstration project, which will add select grid-side equipment to an already secured 12 MW of generation to support resiliency needs from existing Liberty diesel generators. Customers in the Kings Beach community will directly benefit from the microgrid, as the diesel back-up power is applied to provide electric service to residents, businesses, and facilities.

5. Future improvements to initiative

Phase 2 of the Customer Resiliency Program will deliver similar quantifiable societal resiliency benefits in the future, as additional targeted geographic resiliency corridors are developed. Phase 2 will build on and incorporate learnings from Phase 1. Liberty proposes that its Portfolio be delivered through a phased approach, with distinct offerings and benefits for each customer segment and/or geographic area. This approach aims to meet unique customer and community needs with the best and most appropriate solutions. It also builds flexibility into the Portfolio design, enabling Liberty to incorporate learnings and evolve the Portfolio efficiently over time.

7.3.3.9. Installation of system automation equipment

1. Risk to be mitigated

The primary risk mitigated is de-energizing during end-of-line faults that substation relays may not pick up or take long to clear. Having reclosers on the line in series allows for better clearing times for faults downstream of the line reclosers and thus better mitigates fire risk. System automation also provides a reliability benefit with its ability to quickly switch to isolate faults and restore load. This is also known as FLISR (Fault Location, Isolation, and Service Restoration). It will be a valuable resource for service restoration after any PSPS event as well. Installing automation equipment can reduce outage durations and the number of customers impacted.

2. Initiative selection

Liberty's current system automation equipment uses traditional substation and line recloser relaying, which provides the ability to automatically reclose lines during non-high fire threat days. The equipment also has the benefit of remote control and the ability to quickly change settings remotely, such as putting a device into one-shot (fire mode) during high fire threat days. For wildfire mitigation, the use of line reclosers places protective relaying closer to end-of-line faults, allowing devices to quickly clear faults that substation relaying may not pick up. This initiative includes a recloser upgrade program to replace assets to improve system operability, control, and reporting capabilities. Line recloser installation is an effective wildfire mitigation measure. By placing line reclosers with high speed relaying devices out on distribution lines, line faults with lower fault current can be more rapidly detected and cleared.

Liberty is currently developing a Distribution Automation ("DA") strategy that will likely include a single DA controller at a substation that controls multiple devices, both in the substation and on the line. For the past few years, Liberty has focused on installing line reclosers that have communication for SCADA control and the intelligent controllers to handle a DA scheme. Adding DA will enable faults to be rapidly cleared and isolated for better fault location information and rapid system restoration, restoring power to customers in areas where re-energizing line is still safe. The relays also provide valuable information on the type of fault and fault current levels.

3. Region prioritization

Liberty has selected regions by asset condition on mainline feeders to minimize customer outages. Liberty has made progress on implementation of new reclosers and aging recloser replacements in Tier 3 and Tier 2 areas within the Lake Tahoe basin. Liberty is expanding its recloser installations and replacements into its more remote Tier 2 areas going forward. All of Liberty's substations currently have new technology relaying with control and data acquisition (SCADA).

4. Progress on initiative

Four line reclosers were installed in 2020 and two line reclosers were installed in 2021, with plans to install four additional line reclosers in 2022. Liberty plans to continue performing a minimum of three recloser replacements or new installations per year going forward.

5. Future improvements to initiative

Liberty plans to continue installing new line reclosers to better sectionalize and have relaying devices closer to end-of-line to help detect low current faults. Liberty is planning to install four additional line reclosers in 2022. Beyond that, Liberty plans to execute a DA pilot program in 2022. Liberty plans to house a DA controller at one of its substations and control multiple communication enabled reclosers and substation breakers. This allows for FLISR technology to be implemented on Liberty's system.

7.3.3.10. Maintenance, repair, and replacement of connectors, including hotline clamps

Liberty does not currently have an applicable WMP initiative.

7.3.3.11. Mitigation of impact on customers and other residents affected during PSPS event

Liberty does not currently have an applicable WMP initiative.

7.3.3.12. Other corrective action

1. Risk to be mitigated

Tree attachments: This program is intended to reduce the number of tree attachments in the Liberty system. Years ago, it was a common practice to connect overhead service lines to trees. That past practice resulted in a large amount of tree attachments in the Liberty system. Those tree attachments have a potential to pose a wildfire threat in the event that arcing and sparking occurs at the tree attachment location. Rerouting service lines using new poles removes the service lines from being attached to trees and reduces the wildfire ignition potential.

Animal guards: The goal of this program is to protect and insulate substation equipment from debris and animal contact. If an animal contacts substation equipment that is not insulated, there is the potential for a hazardous arc to form, which could lead to a significant outage. Protecting this equipment with Green Jacket insulation will reduce the risk of ignition by animal/debris contact and increase system reliability.

CAL FIRE exempt hardware: Use of CAL FIRE exempt hardware helps to mitigate wildfire potential from electric distribution facilities. When using this equipment, the potential for an ignition event is reduced.

Open wire/grey wire: Open wire and grey wire secondary, which is subject to insulation cracking and failure, can be a source of arcing and sparking. Replacing this wire with properly insulated triplex reduces wildfire ignition potential.

2. Initiative selection

Tree attachments: Tree attachment removal is an important WMP initiative that Liberty intends to continue each year. While this program is not a top priority initiative, it is a WMP program for which yearly progress needs to be made with a focus on top priority tree attachments.

Animal guards: Liberty plans to install insulation hardware on exposed transformer/switchgear bushings, switches, lighting arrestors, phase transformers, and other exposed equipment. Animal contact outages are a regular occurrence in Liberty's service territory, and, in 2020, Liberty saw an increase in squirrel- and bird-related outages. Construction of the new Kings Beach substation prompted Green Jacket insulators to be installed there and at other substations.

CAL FIRE exempt hardware: Liberty uses CAL FIRE exempt hardware on all new facilities. At this time, Liberty does not have a program to actively seek out and replace non-CAL FIRE exempt hardware on existing facilities. Rather, replacements required as a result of the asset inspections done with the timing specified in GO165 are completed using CAL FIRE exempt hardware.

Open wire/grey wire: Liberty is making progress with this initiative by actively identifying areas with open wire/grey wire secondary and then verifying that pole calculations are adequate and then conducting replacement.

3. Region prioritization

Tree attachments: Tree attachment removals are prioritized by focusing on the Tier 3 HFTD area, customer requests, and known dead and dying trees. A survey was conducted in the Tier 3 HFTD area and 316 tree attachments were found. Liberty intends to target those trees starting on the few trees that appear dead or dying.

Animal guards: Green Jacket insulation installation was prioritized by substation and the history of animal/debris contact outages. All substations planned for Green Jacket insulations are within Liberty's HFTD 2 or 3 zones.

CAL FIRE exempt hardware: CAL FIRE exempt hardware is used when replacing facilities as a result of other initiatives or work to improve the system.

Open wire/grey wire: While the Tier 3 HFTD area is given priority, this initiative is also being implemented throughout the remainder of the distribution system which is Tier 2 HFTD.

4. Progress on initiative

Tree attachments: Liberty has been actively working on its tree attachment program with a target of 45 tree attachment removals per year moving forward. In 2021, Liberty completed 37 tree attachment removals. The primary reasons Liberty did not meet its 2021 target for this initiative are that the Tamarack and Caldor fires significantly impacted line construction resource availability and supply chain issues impacted material availability.

Animal guards: Liberty plans to complete animal guard installation on its six largest substations in 2022. Animal guard installations on the smaller substations will be completed in 2023.

CAL FIRE exempt hardware: Liberty is actively using CAL FIRE exempt hardware on all new and replacement installations.

Open wire/grey wire: Liberty continues to make progress with this initiative.

5. Future improvements to initiative

Tree attachments: None at this time.

Animal guards: None at this time.

CAL FIRE exempt hardware: Liberty is exploring the possibility of pairing the use of CAL FIRE exempt hardware with other initiatives such as fuse replacements.

Open wire/grey wire: Liberty intends to continue to identify wire of this type that should be replaced and plans to conduct better tracking of this initiative in the future.

7.3.3.13. Pole loading infrastructure hardening and replacement program based on pole loading assessment program

Liberty does not have an applicable WMP initiative at this time. Pole calculations are performed for all new poles and pole replacements within Liberty's service territory. Any new or existing poles that are installed or modified are designed to G.O. 95 heavy standards using the Osmos O-calc pole loading program.

7.3.3.14. Transformer maintenance and replacement

1. Risk to be mitigated

Leaking and failing transformers affect system reliability and can pose a wildfire threat.

2. Initiative selection

Transformers are inspected and scheduled for replacement as needed as part of G.O. 165 inspections. In addition, any transformer that is leaking or damaged is promptly replaced. Large transformers are tested as a part of their preventive maintenance.

3. Region prioritization

Transformer replacements are implemented throughout the system as necessary.

4. Progress on initiative

In 2021, Liberty replaced 29 overhead transformers during pole replacements resulting from the system survey.

5. Future improvements to initiative

Liberty will continue to replace overhead transformers using FR3 oil. Liberty will also continue to look at other technologies, such as dry type transformers or alternate insulating mediums that are less or non-flammable.

7.3.3.15. Transmission tower maintenance and replacement

Liberty does not have an applicable WMP initiative at this time. Transmission towers and structures are inspected as part of G.O. 165 inspections.

7.3.3.16. Undergrounding of electric lines and/or equipment

1. Risk to be mitigated

Overhead to underground conversions reduces the risk of wildfire in forested areas.

2. Initiative selection

Most of Liberty's undergrounding projects currently underway are customer-initiated Rule 20A conversions of overhead systems based on county-allocated funds. Rule 20A projects are nominated by the city or county and are paid for by the electric utility ratepayers. Because ratepayers contribute the bulk of the costs of Rule 20A programs through utility rates, the projects must be in the public interest.

Due to the high cost of undergrounding in Liberty's service territory, which is over three times as costly as overhead covered conductor projects, undergrounding is not a reasonable or cost-effective option for wildfire mitigation in most cases. Undergrounding circuit segments could be the optimal solution for some distribution replacement projects like covered conductor projects where portions of the project are to be undergrounded due to access considerations and permitting requirements. Specifically, Liberty's planned resiliency corridor on Brockway 4202 and Liberty's Cascade Covered Conductor project will include a total of 0.37 miles of underground electric lines.

When it is decided that a portion of the overhead distribution system should be upgraded, Liberty first considers available alternatives. Alternatives may include conventional replacement with stronger and fire-resistant materials, replacement with covered conductor that includes stronger fire-resistant materials, undergrounding, and other alternatives such as microgrids if practical. In Table 7.3.3- 4 below, Liberty notes the following design considerations, implementation and timeline issues, long-term operations issues, and key assumptions and challenges with undergrounding projects in its service territory.

Table 7.3.3- 4: Undergrounding Projects Considerations

Design Considerations	Implementation Issues and Timelines	Long-Term Operations Issues	Key Assumptions and Challenges
Extensive survey work and civil designs are required.	Civil work is contracted to civil contractors. Difficult to complete and energize projects in the same dig season.	Liberty no longer uses direct bury cable or submersible transformers. Past projects installed with those methods are reaching the end of their useful life and are beginning to require replacement.	Hard rock, groundwater and trees are common in the Liberty service territory. Hard rock makes undergrounding impractical. Groundwater can make undergrounding more difficult and costly. Harm to tree roots must be considered which causes conduit runs to adjust and often be in more costly paved areas. Undergrounding requires extensive permitting and environmental mitigation.

3. Region prioritization

Most of Liberty's undergrounding projects currently underway are customer-initiated Rule 20A conversions nominated by the city or county. Other undergrounding considered as part of resiliency corridors or covered conductor projects are in targeted high fire threat areas and areas intended to reduce the impacts of potential PSPS events.

4. Progress on initiative

The Tahoe Vista Rule 20 project replaces overhead distribution lines with underground electric facilities in the underground district Area 10 (Beach to National) and Area 11 (National to Estates) in Placer County. Total project spend for the Tahoe Vista conversion is $11.3 million. The project location is a 1.25 mile length of State Route 28 impacting approximately 90 private property parcels on the north shore of Lake Tahoe.

In addition to its Rule 20 underground projects, Liberty is installing 0.37 miles of underground as a part of Liberty's planned resiliency corridor on Brockway 4202 and the Cascade Covered Conductor project.

5. Future improvements to initiative

None at this time.

7.3.3.17. Updates to grid topology to minimize risk of ignition in HFTDs

Refer to Section 7.3.3.8.

7.3.4. Asset Management and Inspections

7.3.4.1. Detailed inspections of distribution electric lines and equipment

1. Risk to be mitigated

Detailed inspections of distribution and transmission lines and equipment performed in accordance with G.O. 165 guidelines mitigate the risk of equipment failure by identifying aging and deteriorating equipment in the field. When a Qualified Electrical Worker identifies an issue in the field that needs remediation or repair, work orders are generated to address them. As equipment failure can lead to electrical system faults and has the potential to cause ignition events, Liberty's detailed inspection programs play a vital role in reducing risk.

2. Initiative selection

This initiative is required for compliance with G.O. 165.

3. Region prioritization

Liberty inspects approximately 20% of the system annually, which results in the entire system being inspected every five years before starting the cycle again. As this program has a set schedule to maintain compliance, there is no risk analysis performed for regional prioritization at this time until the risk program is further developed.

4. Progress on initiative

In 2020, a system-wide survey and detailed inspection of all overhead distribution and transmission equipment was completed for Liberty's service territory. The volume of repairs generated from the survey is such that there was a reduced number of detailed inspections performed in 2021.The full level of detailed inspections will resume as scheduled in 2022, encompassing approximately 20% of the overall system.

5. Future improvements to initiative

Liberty's deployment of its new enterprise-wide GIS in 2022 will enhance the accuracy of inspections, reporting and overall record-keeping capabilities of the inspection programs. As Liberty further develops its risk program, the findings from these inspections will be a key driver in the push towards risk-based decision-making for prioritization of asset inspections, repairs, and replacements.

7.3.4.2. Detailed inspections of transmission electric lines and equipment

Liberty does not have a separate program for detailed transmission inspections. There are approximately 75 miles of 60kV lines and 19 miles of 120kV lines that are included in the distribution detailed inspection program. Please refer to Section 7.3.4.1 for initiative details.

7.3.4.3. Improvement of inspections

In 2022 Liberty implemented a QA/QC program for asset inspections and plans to pilot the use of infrared technology in 2023 to improve asset inspections.

7.3.4.4. Infrared inspections of distribution electric lines and equipment

Liberty does not conduct infrared inspections of distribution assets WMP initiative at this time. Liberty plans to implement a pilot program in 2023 to assess the viability of integrating infrared technology into the distribution and transmission inspection cycles. Liberty plans to conduct an infrared pilot program within the Tier 3 HFTD zone of its service territory to evaluate the effectiveness of the technology.

7.3.4.5. Infrared inspections of transmission electric lines and equipment

Liberty does not have an applicable WMP initiative at this time.

7.3.4.6. Intrusive pole inspections

1. Risk to be mitigated

Intrusive pole inspections are a G.O. 165-mandated program for the testing and treatment of wood poles that begin to deteriorate and degrade over time. Poles that are thoroughly inspected and/or proactively treated to extend the service life of the asset significantly reduce safety risk to the system and public. In addition to extending the life of existing poles, the program also helps to identify those assets that need to be replaced before they fail.

2. Initiative selection

Intrusive pole inspections are a G.O. 165 mandated program for the testing and treatment of wood poles that begin to deteriorate and degrade over time. The intrusive pole inspection program tests the integrity of wood poles both visually and through internal examination of the poles to identify damage, decay, and approximate shell thickness. A report identifies poles that pass inspection as well as those that need to be replaced or need remediation, such as pole stubbing or treatment application. This program can reduce replacement costs, extend the life of poles and increase the safety and reliability of the overall system.

3. Region prioritization

Intrusive pole inspections are currently performed throughout Liberty's service territory annually on a 10-year cycle.

4. Progress on initiative

In 2021, Liberty performed intrusive inspections on 3,500 poles and forecasts performing 2,600 intrusive inspections in 2022.

5. Future improvements to initiative

Liberty plans to use its fire risk map and circuit risk analysis to inform future intrusive pole inspection schedules.

7.3.4.7. LiDAR inspections of distribution electric lines and equipment

Liberty does not have a LiDAR inspections of distribution electric lines and equipment WMP initiative at this time.

7.3.4.8. LiDAR inspections of transmission electric lines and equipment

Liberty does not have an applicable WMP initiative at this time.

7.3.4.9. Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations

1. Risk to be mitigated

In 2020, Liberty performed a full system survey of all of its overhead assets. As a result of this survey, numerous operations and maintenance ("O&M") repairs were identified. These repairs will reduce the risk of wildfire ignition as well as improve reliability.

2. Initiative selection

This initiative was selected in order to form a baseline of detailed inspections in Liberty's new tracking software as well as facilitate the deployment of resources to wildfire risks within a short timeframe.

3. Region prioritization

As required, Liberty prioritized Level 1 and Level 2 findings for repairs, targeting its highest HFTD zones first. Liberty is developing an approach for Level 3 findings that will be based on Liberty's updated fire risk map and Liberty's pole risk assessment discussed in Section 4.3. Liberty will utilize its Pole Risk of Failure categories of low, medium, and high. For example, a pole can be designated a Level 3 priority because there was an issue to the High Voltage signage. While this condition needs to be remediated within five years, it typically will not result in a pole falling in-service, and thus has a low risk of failure. However, if a Level 3 pole has a condition code of cracked pole, the risk of failure is moderate due to the structural integrity being compromised.

4. Progress on initiative

To date, Liberty has completed all Level 1 repairs in the region. Liberty plans to complete Level 2 findings in 2022 and Level 3 findings by Q4 2025, as required.

5. Future improvements to initiative

Liberty plans to complete full system surveys on a periodic basis yet to be determined.

7.3.4.10. Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations

Liberty does not currently have an applicable WMP initiative.

7.3.4.11. Patrol inspections of distribution electric lines and equipment

1. Risk to be mitigated

A qualified electrical worker patrols the electric system looking for issues with overhead structures or obvious hazards that impact the safety and reliability of the system. Refer to section 7.3.6.3 for enhanced patrols on heightened wildfire risk days.

2. Initiative selection

This initiative is required for compliance with G.O. 165.

3. Region prioritization

Patrols are performed throughout Liberty's service territory in accordance with the schedules outlined in G.O. 165.

4. Progress on initiative

Liberty completed all patrols in 2021 and plans to complete all patrols in 2022 in accordance with the schedules outlined in G.O. 165.

5. Future improvements to initiative

Due to the alpine terrain and other factors such as limited vehicle access, Liberty plans to utilize helicopters to make patrol inspections of remote lines more efficient and cost-effective. Liberty used a helicopter service to complete required patrols in 2021.

7.3.4.12. Patrol inspections of transmission electric lines and equipment

Liberty does not have a separate program for patrol transmission inspections. There are approximately 75 miles of 60kV lines and 19 miles of 120kV lines that are included as part of the distribution inspection program. Please refer to Section 7.3.4.11 for initiative details.

7.3.4.13. Pole loading assessment program to determine safety factor

Liberty does not currently have a pole loading assessment WMP initiative. Any new or existing poles that are installed or modified are currently designed to G.O. 95 heavy standards using the Osmos O-calc pole loading program. Pole calculations are performed for all new poles and pole replacements within the service territory.

7.3.4.14. Quality assurance / quality control of inspections

1. Risk to be mitigated

With the increased reliance on contractors, due primarily to WMP activities that did not exist until recently, the company recognized the need to establish a robust QA/QC program to improve compliance with company and regulatory standards. Liberty has developed a QA/QC program for detailed inspections and is implementing the program in 2022. Refer to Attachment F: Liberty Asset Inspection QA/QC Program.

2. Initiative selection

A QA/QC program should reduce the potential for non-compliance by confirming that inspections are performed in compliance with regulatory standards and that projects are built to design specifications. The data generated by this program should serve as a critical tool in identifying issues with electric asset inspections, which will lead to improvements in inspection processes at Liberty.

3. Region prioritization

The QA/QC program will encompass the entire service territory with a focus on assets in Tier 2 and Tier 3 of the HFTD and other critical facilities identified by Liberty's risk ranking analyses.

4. Progress on initiative

Liberty's QA/QC program of its inspections will be implemented in 2022. A qualified third-party contractor will be selected in order to validate that Liberty is conducting inspections in an effective manner in compliance with G.O. 165 inspection process and G.O. 95 construction standards.

5. Future improvements to initiative

Going forward, Liberty will look to incorporate any available risk-based data to further refine the QA/QC processes and prioritization of asset inspections.

7.3.4.15. Substation inspections

1. Risk to be mitigated

Substation inspections can identify several issues before they become serious problems. The primary risk to be mitigated from substation inspection is catastrophic failure of equipment leading to ignition of nearby vegetation.

2. Initiative selection

Liberty conducts its substation inspections in accordance with its current G.O. 174 Substation Inspection Plan. Most substations that are accessible year-round are inspected on a quarterly basis. Substations that are not accessible for normal daily operations are inspected on an annual basis.

3. Region prioritization

There is no region prioritization for this initiative. It is an established program with 12 substations to inspect.

4. Progress on initiative

Liberty completed all substation inspections in 2021 and plans to complete all substation inspections in 2022 in accordance with plan.

5. Future improvements to initiative

None. Liberty will continue to follow its current G.O. 174 substation inspection plan.

7.3.5. Vegetation Management and Inspections

7.3.5.1. Additional efforts to manage community and environmental impacts

Maintaining a comprehensive Vegetation Management ("VM") program helps prevent certain tree and power line conflicts and supports wildfire mitigation. Properly implemented vegetation management activities require prevention of unintended or unnecessary consequences that negatively impact the environment and communities they are meant to protect. Liberty is committed to sustainable practices, conducting vegetation management in an environmentally responsible manner, and supporting the community.

1. Risk to be mitigated

Liberty understands the potential for VM activities to negatively impact the environment and communities in which they are implemented. Liberty requires that such activities be performed in accordance with its documented resource protection measures to mitigate potential negative environmental impacts. Liberty works with customers, property owners, and surrounding land managers to implement vegetation management projects while minimizing negative impacts and promoting benefits to the community.

Community Impacts: Prior to executing a work plan, Liberty invests a significant amount of effort into the planning and preparing vegetation projects. Regardless of their necessity, vegetation projects cannot be successfully implemented with landowner opposition. Some level of mitigation can be achieved in most cases, but the more a project deviates from the plan the less likely it is to achieve wildfire mitigation objectives. As vegetation clearances are better maintained, vegetation threats are moving farther outside of easements and permit. Cooperation from landowners and public land managers is critical to adequate mitigation efforts.

Environmental Impacts: VM program planning includes best practices for water quality, terrestrial wildlife, sensitive and rare plants, and non-compatible plant management, which help to address environmental concerns that may arise from VM activities. Liberty also works with local consultants who conduct heritage surveys and provide recommendations to avoid causing negative impacts to and possible loss of cultural resources. Liberty performs vegetation management while preserving the integrity of natural and cultural resources via effective planning and execution of its WMP objectives.

2. Initiative selection

The success of Liberty's VM program is dependent on its ability to implement projects in a manner that manages both community and environmental impacts effectively, while reducing wildfire risk. Liberty maintains working relationships with local, state, and federal land management agencies to identify appropriate measures to eliminate or minimize negative impacts to natural and cultural resources. In order to achieve successful project implementation, Liberty engages with its customers and community partners to provide communications about planned vegetation management projects.

Community Impacts: Liberty collects customer satisfaction information from J.D. Power surveys and uses the data to select initiatives to improve customer service. Over the last few years, Liberty has instituted several measures to improve customer service, communications, and operations.

Environmental Impacts: Liberty recognizes the importance of managing vegetation in a manner that is sustainable, safe, and economical. In determining proper technique for controlling vegetation along rights-of-way, Liberty follows the practices described in the American National Standard A300 (Part 7) Integrated Vegetation Management (IVM) standards. Practicing IVM promotes sustainable plant communities that are compatible with the use of the land as a utility right-of-way. This is achieved by using a combination of treatment methods that are selected after consideration of environmental impacts, effectiveness, economics, site characteristics, and other factors.

Research on the use of various control methods for vegetation management, including cost-benefit analysis and effects on the environment, has been conducted for over 50 years, beginning with the Pennsylvania State Game Lands 33 research project in 1953. Previous and current research demonstrate that IVM produces positive effects on plant community and wildlife diversity and an increase in ecosystem services along power line corridors. Liberty follows current research to select appropriate control methods with the goal of establishing and maintaining early-successional, biodiverse vegetation communities capable of withstanding encroachment by incompatible species that threaten electrical reliability and contribute to fuel loading.

3. Region prioritization

Communication and resource protection initiatives occur throughout Liberty's service territory. The prioritization of these efforts is determined by the portfolio of upcoming capital and vegetation-related projects and are planned at the region level. Liberty coordinates with surrounding land managers to complete environmental and cultural surveys of project areas prior to implementation. Some efforts to manage community and environmental impacts are prioritized as a result of collaboration with other agencies, land managers, and property owners to increase efficiency of available resources. Additional prioritization may be given to projects focused on forest resiliency and fuel reduction surrounding critical community infrastructure.

4. Progress on initiative

Since filing its initial WMP in 2019, Liberty has been focused on restructuring its VM program to improve wildfire mitigation effectiveness. Throughout the program development process managing community and environmental impacts has been a key component of initiative selection and wildfire mitigation efforts.

Community Impacts: For the past two years, Liberty's Vegetation Management and Communications departments regularly coordinated to improve customer service and communications related to vegetation management. When gaps are identified in how community impacts are managed, efforts are implemented to enhance customer outreach. Below are examples of some concerns as well as measures that were taken:

- Vegetation Management's responses to incoming calls could take as long as five weeks.
  - Solution: faster turnaround for returned calls.
- Wood left on property from vegetation management work on private property and insufficient pre-work notification/education
  - Improved expectation management by sending direct mail to customers prior to vegetation management work informing customers what to expect, including wood left on property
  - Instituted a new wood hauling program for private property owners
  - Worked with other agencies to provide easier ways for property owners to remove wood
  - Updated door hangers to provide better communication between customers and contractors
- Concerns about removing too many trees or overly aggressive vegetation management
  - Improved and more frequent communications focused on the importance of vegetation management as a key factor of Liberty's wildfire mitigation plan and operations
  - Better communication about benefits of vegetation management such as reducing frequency and duration of power outages

These efforts have been productive in managing community impacts and addressing customer concerns.

The Communications Department at Liberty completed a study in 2021 to evaluate the effectiveness of various communication media, which helped determine how to enhance vegetation management messaging. Liberty generally uses four methods of providing large scale communications. Bill inserts are used to message all customers, and social media was a good supplement to remind or reinforce a message. Email is effective, and Liberty is working to increase its database of email addresses to increase direct electronic messaging. Direct mail was the most effective means to reach Liberty's customers. Liberty created direct mail notifications formatted as postcards to inform customers of upcoming vegetation inspections or maintenance. Below (Figure 7.3.5- 1) is a sample postcard notification that is sent after an inspection has been completed, but prior to work being implemented.

Figure 7.3.5- 1: Postcard Notification after VM Inspection

DEAR CUSTOMER,

LIBERTY WOULD LIKE TO INFORM YOU THAT VEGETATION MAINTENANCE WORK WILL BEGIN IN AND AROUND YOUR NEIGHBORHOOD LN THE COMING WEEKS. LIBERTY'S PROFESSIONAL ARBORISTS EMPLOY UTILITY PRUNING AND TREE REMOVAL PRACTICES RECOMMENDED BY THE INTERNATIONAL SOCIETY OF ARBORICULTURE, AMERICAN NATIONAL STANDARDS INSTITUTE, AND THE ARBOR DAY FOUNDATION. THESE PRACTICES GUIDE US IN MAINTAINING A HEALTHY COMMUNITY FOREST AND KEEPING THE ELECTRIC RIGHT- OF- WAY CLEAR OF HAZARDS.

THIS IS WHAT YOU CAN EXPECT

- TREE CREWS WILL KNOCK ON YOUR DOOR BEFORE BEGINNING WORK
- IF NO ONE IS HOME WE WILL LEAVE A DOOR HANGER
- TREE CREWS WILL BE PRUNING FOR POWER LINE CLEARANCE
- TREE CREWS WILL CLEAN UP DEBRIS

FIELD CREWS WILL BE PRACTICING SOCIAL- DISTANCING DURING THIS TIME, SO PLEASE RESPECT THEIR SPACE. IF YOU HAVE ANY QUESTIONS ABOUT THIS PROJECT OR OUR VEGETATION MANAGEMENT PRACTICES, PLEASE CONTACT CATREE@LIBERTYUTILITIES.COM OR VISIT https://libertyutilities.com/cavegetation/

SINCERELY,

VEGETATION MANAGEMENT DEPARTMENT

Environmental Impacts: In 2021, Liberty completed a Biodiversity Exposure Assessment to identify areas where facilities owned and maintained by Liberty intersect sites of biological importance. The assessment analyzed geospatial data to categorize and quantify areas of importance according to International Union for Conservation of Nature (IUCN) guidelines for applying protected area categories. The assessment identified 80 intersecting sites totaling 5,602 acres of high biodiversity value. Protected areas and biologically important areas outside of protected areas identified by the 2021 Biodiversity Exposure Assessment will follow the same avoidance and minimization measures described as best practices for resource protection by the utility vegetation management industry and coordinating land management agencies.

Table 7.3.5- 1: Overview of Biologically Important Areas within Liberty's Service Territory

DATASET	DESCRIPTION	NUMBER OF SITES	AREA (ACRES)
Areas of Conservation Emphasis	Areas of High Biodiversity and Rare Vegetation	32	3,200
Areas of Critical Environmental Concern	Special Management Attention Needed	1	0.4
Important Bird Areas	Important Bird Habitat	4	154
U.S. Protected Areas Database	Federal Land Management and Conservation Areas	25	921.3
U.S. Protected Areas Database	Research or Educational Area	1	12
U.S. Protected Areas Database	Inventoried Roadless Area	5	18
U.S. Protected Areas Database	Grazing Allotment	2	1,198
U.S. Protected Areas Database	State Land Management and Conservation Areas	8	55
U.S. Protected Areas Database	Wild and Scenic River	2	42
	Total Sites and Acres	***80***	***5,601***

In 2021, Liberty continued to support the Liberty Utilities Resilience Corridors Project on land managed by the USDA Forest Service ("FS"). This project authorizes the treatment of approximately 7,600 acres of National Forest to improve forest health and resiliency adjacent to Liberty facilities. Liberty's role emphasizes the removal of incompatible vegetation and hazard trees likely to disrupt the flow of electric service or contribute to wildfire risk. The National Forest Foundation ("NFF") is performing project preparation and administration for this project on behalf of the Lake Tahoe Basin Management Unit ("LTBMU"). After planning and preparing work areas, the FS will award timber sale contracts for project implementation. Although Liberty was not authorized to implement all of its work plan for this initiative in 2021, Liberty was able to redirect efforts for the preparation and layout of work units (approximately 430 acres) expected to be issued by the FS in 2022. The project is anticipated to be complete in three to five years. Liberty is committed to providing continued support for this project until completion. Because the project is managed by the FS with assistance from the NFF, Liberty cannot provide projected and actual quantitative units of progress for this specific activity in future updates.

Resource constraints hindered the ability of the FS to complete environmental and cultural resource surveys required prior to implementing work. To facilitate continued progress, Liberty secured contracts with environmental consulting firms to coordinate with FS resource specialists and perform the necessary surveys. The experience gained from working closely with the LTBMU on this project motivated Liberty to initiate similar concepts with other public and large private land managers, and Liberty is actively exploring additional opportunities to collaborate with public land management agencies throughout the service area. The Tahoe National Forest ("TNF") has been receptive to proposed VM activities that enhance forest resiliency and reduce fuel loads adjacent to utility infrastructure. In 2021, hazard tree removal and fuel management activities were conducted along 3.1 miles of right-of-way on the TNF (Figure 7.3.5- 2), and additional projects are being planned for the remainder of the TNF land on which Liberty operates and maintains electrical assets.

Figure 7.3.5- 2: Hobart 7700 Project

5. Future improvements to initiative

To better manage community impacts, Liberty is working to shift the focus of this initiative from quantitative targets to qualitative outcomes. Quantitative metrics will be used to evaluate progress and establish a baseline for future evaluations. Liberty's near-term improvements are related to improving processes for capturing data in order to better define goals and set meaningful targets. Improving the quality of data used will improve the ability to manage for desired outcomes. Liberty continues to develop processes and procedures, including improving customer communications, developing a tree replacement program, and additional integrated vegetation management program development.

<u>Community Impacts</u>: Liberty is developing processes to improve data-based decision-making and program management by measuring customer contact attempts and outcomes for vegetation management inspections and maintenance.

Liberty continues to improve information provided to customers and create opportunities for positive interactions with Liberty:

- Clarify and standardize customer notification processes for contractors
- Update Tree Work Notification Form ("TWNF")
- Improve fuel management processes for private properties
- Establish appropriate timelines for intervals between property visits

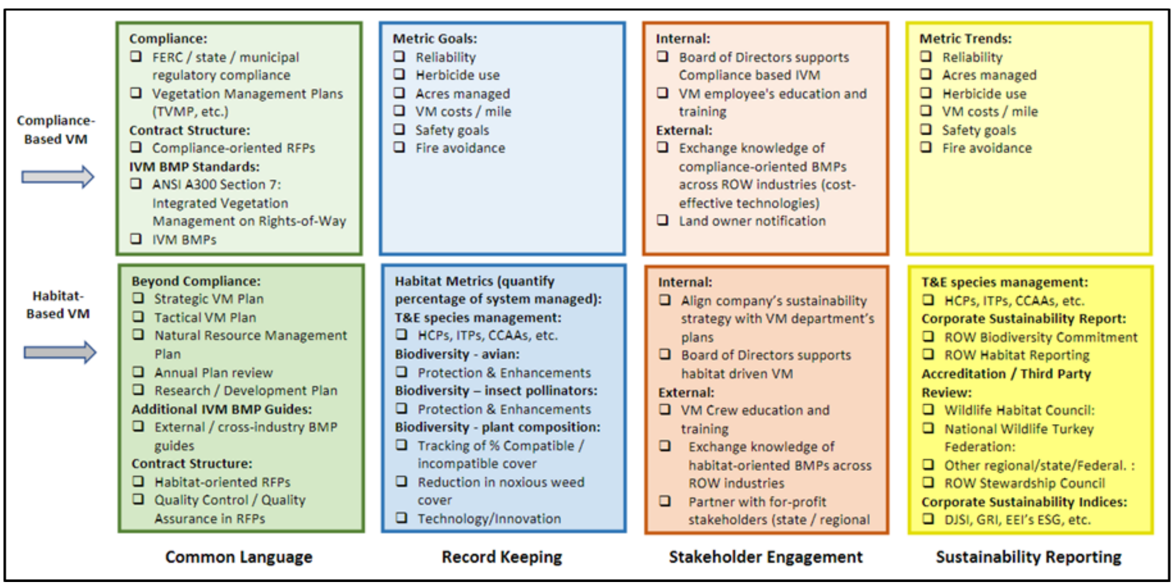
Liberty procures a significant amount of vegetation management services through vendors who participate in the CPUC Utility Supplier Diversity Program. As the need for contract resources increases, Liberty is reviewing its contracting strategy to explore ways to support that program and add value to the community through sourcing goods and services provided by local and regional businesses that also invest in sustainable development of the community.

Liberty is developing a tree replacement program to offer customers plant materials that are appropriate for installing adjacent to utility corridors after Liberty has completed the removal of incompatible vegetation. Liberty is working with a local nursery to provide species that are adapted to the region, size appropriate at maturity, and to the extent possible, fire-wise species that may contribute to wildfire mitigation if an incident were to occur.

Environmental Impacts: Liberty plans to improve management of environmental impact by using ANSI A300 Part 7 Standard and Best Management Practices for Integrated Vegetation Management (IVM) to manage projects. Selection of control methods when IVM principals are adhered to has been demonstrated to reduce future maintenance needs and improve environmental quality by increasing biodiversity and ecosystem services. This will include creating a long-term plan to execute projects across the service system to promote compatible and sustainable plant communities on the landscape where electrical equipment operates. The IVM plan will be implemented using a phased approach with considerations for both near-term and long-term program objectives. The initial phase builds on information gained through the Biodiversity Exposure Assessment and develops a framework for implementing projects. Near-term IVM Program development goals include:

- Conduct program assessment using the Vegetation Management Maturity Model.[21]
- Incompatible and compatible priority plant database; Liberty includes consideration of practices that promote compatible species and does not focus solely on incompatible vegetation management control methods.
- Complete Plant Identification and Landscape Awareness Training.
- Begin monitoring and inventorying priority plants within maintenance areas.

Figure 7.3.5- 3: Overview of VM Maturity Model



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[21] The Vegetation Management Maturity Model was designed by the Utility Arborist Association and the University of Illinois Chicago Energy Resources Center to benchmark utility vegetation management ("UVM") operations, identify areas to enhance practices, and drive change in UVM programming towards more sustainable and environmentally conscious management practices.

Figure 7.3.5- 4: Compatible plant propagation techniques

Compatible Shrub Name	Canopy Release	Cutting/ Grazing/ Pruning	Field Sowing	Live Stakes	Mulching	Planting	Post Fire Seeding	Prescribed Fire	Protection	Seeding	Stem Layering
Big Sagebrush (*Artemisia tridentata*)							x	x	x	x	
Bitterbrush (*Purshia tridentata*)		x							x	x	x
Clustered Field Sedge (*Carex praegracilis*)		x				x		x			
Common Manzanita (*Arctostaphylos manzanita*)		x						x	x		x

7.3.5.2. Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment.

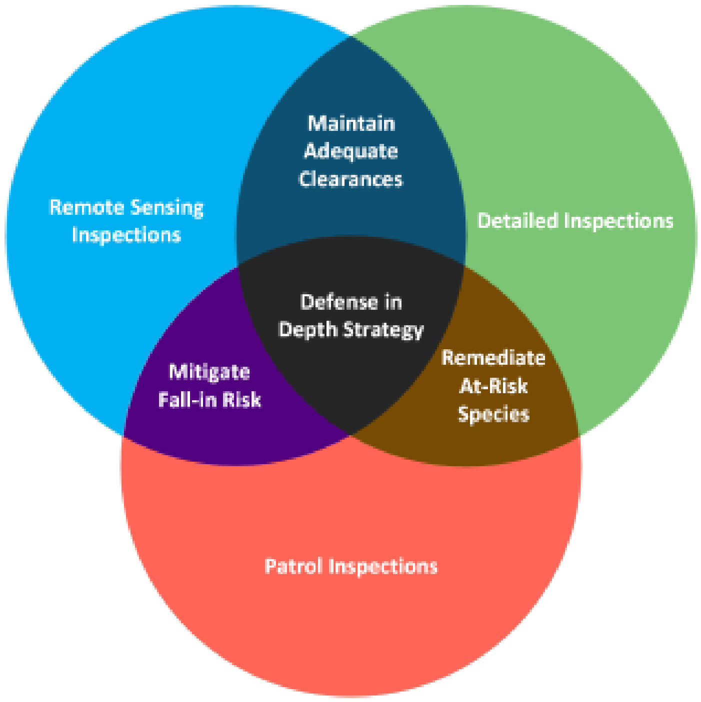
Liberty performs detailed inspections along entire circuits to prescribe pruning and removal of vegetation that contributes to increased risk to electric line operations. These inspections are used as a safeguard against vegetation threats and to monitor conformance to applicable laws and regulations.

1. Risk to be mitigated

Detailed vegetation inspections are used to identify and prescribe tree work for at-risk species and hazard trees. The detailed inspections are comprehensive, and arborists are instructed to inspect any problematic vegetation with the potential to impact utility assets. These inspections are also used to assess the effectiveness of other protocols in place to maintain adequate vegetation clearances and to locate and remove obvious hazards within the utility strike zone. Work generated from detailed inspections is typically associated with remediation of trees outside of the normal maintenance zones that appear healthy but are determined to be a hazard to utility infrastructure upon inspection. Mitigating this risk often results in removal of the hazard tree. Due to the large number of absent property owners and additional permitting requirements throughout the service territory, securing permission to remove trees is a lengthy process and can be particularly difficult when the tree does not appear to be a hazard.

Using a combination of inspections and management practices, Liberty has developed a defense-in-depth strategy to mitigate vegetation threats and maintain clearances to reduce wildfire risk (see Figure 7.3.5- 5 below). Liberty has developed this strategy in which inspection and maintenance activities form a multifaceted approach to managing risk of vegetation and power line conflicts. In order to promote continued fire safety, public safety, and reliability of entire circuits throughout the service territory, Liberty performs LiDAR inspections of vegetation to achieve clearances around electrical infrastructure (described in Section 7.3.5.7 and Section 7.3.5.20) and patrol inspections to locate and remove obvious hazard trees (described in Section 7.3.5.11 and Section 7.3.5.15). Each vegetation inspection initiative serves a primary purpose within the vegetation management strategy, but inspectors are trained to prescribe work for any vegetation condition that is expected to fail and strike electric facilities or grow into regulated clearance zones prior to the next scheduled inspection and maintenance activities. This multi-faceted approach is designed to achieve and maintain adequate vegetation clearance distances, remediate at risk species, and remove obvious hazard trees with strike potential in an effective and complimentary manner. This approach provides a method of assuring the efficacy of inspections while informing future VM activities.

Figure 7.3.5- 5: Diagram of Liberty's Vegetation Threat Mitigation Strategy:



2. Initiative selection

Liberty's detailed vegetation inspections are designed to prevent conflicts between vegetation and electrical assets and to comply with applicable rules and regulations. During the inspection process, tree and site conditions are assessed per ANSI A300 (Part 9) Tree Risk Assessment guidelines to determine tree risk. If work is required to remediate any concerns identified during the inspection process, the inspector will prescribe corrective actions to mitigate the identified risk.

3. Region prioritization

Liberty monitors vegetation conditions using several sources of information for VM inspection planning and prioritization. Factors taken into consideration when planning and prioritizing detailed inspections of vegetation include vegetation density, maintenance history, regional fire risk rating based on CPUC fire threat areas and REAX fire risk ratings, customer tree inspection requests, observations from field employees and contractors. Emergency pruning or removal is performed when a tree poses an imminent threat to the electrical facilities.

Liberty has updated the Vegetation Management Plan (VM-02) to include a description of all applicable vegetation related codes and regulations. The plan describes the elements (*i.e.*, pruning, removal, slash removal, pole brushing, clearance requirements, notification process, etc.) that Liberty employs in order to comply with these codes and regulations.

Liberty developed a Hazard Tree Management Plan (VM-03) to identify, document, and mitigate trees that are located within the utility strike zone and are expected to pose a risk to electric facilities based on the tree's observed structural condition and site considerations.

Liberty developed a Vegetation Threat Procedure (VM-05) that describes the methods of prioritization of identified threats on the Liberty system that are discovered through implementation of VM plans and procedures.

4. Progress on initiative

Table 7.3.5- 2: Total Vegetation Inspections Completed by Liberty in 2021

WMP Initiative Category	WMP Initiative Number	WMP Initiative Activity	Unit of Measure	2021 Target Production	2021 Actual Production
Vegetation Management & Inspections	7.3.5.2	Detailed Inspections	Line Miles Inspected	207	178
Vegetation Management & Inspections	7.3.5.7	LiDAR Inspections	Line Miles Inspected	701[22]	701
Vegetation Management & Inspections	7.3.5.11	Patrol Inspections	Line Miles Inspected	150	179
Vegetation Management & Inspections	7.3.5.13	Quality Control Inspections	Line Miles Inspected	136	156
Total Vegetation Inspections for 2021				**1,194**	**1,214**

Liberty's target for detailed inspections of vegetation along its electric lines and equipment was 207 line miles in 2021. Liberty completed approximately 178 line miles of detailed vegetation inspections in 2021. Liberty was successful in achieving its overall objective for vegetation inspections and completed vegetation inspections along a total of 1,214 overhead line miles. With a total of 701 overhead line miles to inspect and maintain, Liberty nearly inspected the entire system twice.

5. Future improvements to initiative

Liberty's detailed inspections of vegetation along its electrical lines and equipment is a comprehensive patrol of vegetation within and adjacent to the utility right-of-way. This approach has been successful in mitigating risk posed by hazard trees and improving system resilience and reliability. Liberty will continue to perform these comprehensive, detailed inspections to continue to mitigate the risk posed by hazard trees. Liberty has augmented its detailed inspections with annual remote sensing inspections of 100% of its territory described in Section 7.3.5.7 and Section 7.3.5.8.

7.3.5.3. Detailed inspections and management practices for vegetation clearances around transmission electrical lines and equipment.

Liberty's detailed inspections of vegetation around transmission electric lines and equipment do not differ from that for distribution electric lines and equipment. Refer to Section 7.3.5.2.

[22] Due to previously unknown errors in the original GIS source data, Liberty projected 730 miles of LiDAR inspections in its 2021 plan with the objective of inspecting 100% of the line miles. Liberty accomplished its objective in 2021, and the accurate total line miles for this category is 701.

7.3.5.4. Emergency response vegetation management due to red flag warning or other urgent climate conditions

Although Liberty does not currently have a specific applicable WMP initiative, the inspections and vegetation management work performed in Sections 7.3.5.2, 7.3.5.3, 7.3.5.5, 7.3.5.7, 7.3.5.8, 7.3.5.11, 7.3.5.12, 7.3.5.15, and 7.3.5.16 support preparation and identification of these types of events.

7.3.5.5. Fuel management (including all wood management) and reduction of "slash" from vegetation management activities

Liberty recognizes the need for additional efforts to reduce accumulation of woody debris that can ignite or contribute to fire spread and intensity. Liberty has implemented a Fuel Management Program as a precautionary measure to reduce wildfire risks by removing wood and treating brush and slash after vegetation maintenance is performed. Additional treatments that reduce surface fuels from previous activities and those that further reduce fuel loads are also implemented. This program is intended to align more closely with joint goals of agency partners and the local community so vegetation management fuel load is treated in a manner that reduces both the fire ignition risk and the potential for increased fire intensity.

Figure 7.3.5- 6: Slash and Wood Treatment Comparison

Wood and Slash	Treatment Comparison	Parcel and Ownership Type			
		Small privately owned parcel	**Small publicly owned parcel**	**Large privately owned land**	**Large publicly owned land**
Wood greater than 4" diameter	Previous treatment	Cut to length and leave in place		Cut to length or fell whole tree and leave in place or cut to length and haul to decking location	
	Current treatment	Offer wood removal service	Cut and stack firewood or remove and haul upon request	Utilize specialized equipment to remove from landscape everywhere feasible or an alternative is requested	
Wood less than 4" diameter and within 100' of access road	Previous treatment	Chip and haul off-site or broadcast back onto the landscape			
	Current treatment	Chip and haul off-site or broadcast back onto the landscape			
Wood less than 4" diameter and more than 100' from access road	Previous treatment	Lop and scatter or pile slash per landowner request			
	Current treatment	Utilize specialized equipment to remove slash from landscape or chip and broadcast		Utilize specialized equipment to chip and broadcast and to reduce lop and scatter treatments	

MITIGATION INITIATIVES

1. Risk to be mitigated

Prior to developing augmented operations to manage wildfire risk, Liberty performed all vegetation management activities in accordance with Local, State, and Federal rules for maintaining the infrastructures and handling woody debris generated after pruning and removing trees. The applicable rules and guidelines did not adequately address the potential for surface fuel accumulation. Since 2020, Liberty has worked on developing a fuel management program to mitigate wildfire risk by treating woody debris that can contribute to the potential spread or intensity of wildfires.

Figure 7.3.5- 7: Prioritizing VM work by high wildfire risk and high fuel loading

2. Initiative selection

The goal of the Fuel Management Program is to treat fuel generated by previous vegetation management projects and establish new procedures to treat wood and slash from current and future work.

3. Region prioritization

Selection of fuel management and reduction of slash projects are based on multiple factors, such as fire risk ratings, proximity of overhead conductors to the Wildland Urban Interface, landowner cooperation, ability to carry out activities in alignment with environmental and cultural resource protection measures, and other relevant factors that may affect the success of such projects. Tier 3 and Tier 2 fire hazard severity zones are given first priority.

In spring of 2021, the Vegetation Management team conducted an analysis to establish priorities for Fuel Reduction Projects to complete by end of 2021. Liberty's entire system was evaluated to prioritize project locations by conducting a circuit analysis using the following criteria:

- Liberty fire risk polygons
- Last detailed routine maintenance
- LiDAR detections
- Locally known conditions
- Agency cooperation
- Tiers 2 and 3
- Taking advantage of already planned work *e.g.*, environmental permitting for re-conductor projects, timber sales, etc.

4. Progress on initiative

Since the filing of its 2021 Wildfire Mitigation Plan, Liberty has completed various projects focused on fuel management and reduction of slash. These projects included community fuel treatments, collaboration with large landowners and agency partners, substation defensible space, and wood recycling efforts. Liberty completed 16 fuel management projects in 2021 throughout its territory. The table below details Liberty's fuel management and slash reduction efforts throughout 2021.

Table 7.3.5- 3: Liberty Fuel Management Projects

Initiative Name	Project Category	Project Name	Line Miles	Acres Treated	Trees Removed	Landowner Participation	Tons of Biomass Removed
FUEL MANAGEMENT	COMMUNITY FUEL REDUCTION	TOWN OF TRUCKEE - GLENSHIRE	11	13.3	48	1	N/A
FUEL MANAGEMENT	COMMUNITY FUEL REDUCTION	SUNRISE CREEK	0.27	1.09	96	5	N/A
FUEL MANAGEMENT	COMMUNITY FUEL REDUCTION	RAINBOW TRACT	0.1	0.89	12	1	6.38
FUEL MANAGEMENT	LANDOWNER PARTNERSHIPS	TC 5201 CALTRANS	0.56	2.03	55.75	1	5.29
FUEL MANAGEMENT	SUBSTATION DEFENSIBLE SPACE	MEYERS SUBSTATION	0.56	9.59	320	N/A	140.49
FUEL MANAGEMENT	LANDOWNER PARTNERSHIPS	HAWKINS RANCH RD	0.18	0.36	10	1	N/A
FUEL MANAGEMENT	COMMUNITY FUEL REDUCTION	HIGHLANDS HOA	3	5.45	339.97	106	168.08
FUEL MANAGEMENT	CUSTOMER FUEL TREATMENT	6661 PORTOLA MCLEARS RD	0.64	2.32	40	1	N/A
FUEL MANAGEMENT	CUSTOMER FUEL TREATMENT	WASHOE WAY CAPITAL JOB	0.04	2.53	10	6	20.34
FUEL MANAGEMENT	CUSTOMER FUEL TREATMENT	WOOD REMOVAL	16.3	168.86	1302	444	650.46
FUEL MANAGEMENT	LANDOWNER PARTNERSHIPS	CALIFORNIA TAHOE CONSERVANCY FIREWOOD BUCKING	0.84	27.22	48	1	N/A
FUEL MANAGEMENT	SUBSTATION DEFENSIBLE SPACE	NORTHSTAR SUBSTATION	N/A	2.7	N/A	1	23.15

Initiative Name	Project Category	Project Name	Line Miles	Acres Treated	Trees Removed	Landowner Participation	Tons of Biomass Removed
FUEL MANAGEMENT	COMMUNITY FUEL REDUCTION	650 ROW WORK	6.28	33.23	8072	5	N/A
FUEL MANAGEMENT	COMMUNITY FUEL REDUCTION	CALDOR FIRE BIOMASS DISPOSAL	0.21	3.35	68	4	14.12
FUEL MANAGEMENT	LANDOWNER PARTNERSHIPS	HOBART PROJECT	3.1	10.18	1372	3	1090.35
FUEL MANAGEMENT	LANDOWNER PARTNERSHIPS	EAGLE ROCK TRACK CHIPPER	0.4	5	215	1	N/A
PROJECT TOTALS			**43.48**	**288.1**	**12008.72**	**581**	**2118.66**

Liberty utilized various facilities to recycle wood biomass removed from vegetation management activities. The biomass is repurposed into wood chips, compost, mulch, and firewood.

Table 7.3.5- 4: Biomass Removed

Project	Contractor	Tons	Facility	End Use	Date
CUSTOMER FUEL TREATMENT	RK	50.5	Eastern Regional Landfill	Wood chips	5/13/2021
CUSTOMER FUEL TREATMENT	RK	19.07	Full Circle Compost	Wood chips	5/19/2021
RAINBOW TRACT	MFE	3.93	South Tahoe Refuse	Compost/ mulch	6/2/2021
RAINBOW TRACT	MFE	2.45	South Tahoe Refuse	Compost/ mulch	6/4/2021
TC 5201 CALTRANS	MFE	5.29	Eastern Regional Landfill	Wood chips	6/16/2021
CUSTOMER FUEL TREATMENT	RK	12.66	Eastern Regional Landfill	Wood chips	6/21/2021
CUSTOMER FUEL TREATMENT	MFE	12.85	Eastern Regional Landfill	Wood chips	6/28/2021
WASHOE WAY CAPITAL JOB	MFE	20.34	Eastern Regional Landfill	Wood chips	7/26/2021
MEYERS SUB WOOD HAUL	RK	140.49	Full Circle Compost	Wood chips	7/29/2021
HIGHLANDS PROJECT	OUTS	168.0865	Eastern Regional Landfill	Wood chips	9/17/2021
CUSTOMER FUEL TREATMENT	MFE	13.12	Eastern Regional Landfill	Wood chips	9/28/2021

Project	Contractor	Tons	Facility	End Use	Date
CUSTOMER FUEL TREATMENT	OUTS	119.46	Eastern Regional Landfill	Wood chips	10/8/2021
NORTHSTAR SUB WOOD HAUL	OUTS	23.15	Eastern Regional Landfill	Wood chips	10/13/2021
CUSTOMER FUEL TREATMENT	RK	107.65	Eastern Regional Landfill	Wood chips	10/13/2021
CUSTOMER FUEL TREATMENT	RK	24	Neighborhood Firewood	Firewood	10/13/2021
CUSTOMER FUEL TREATMENT	OUTS	163.11	Eastern Regional Landfill	Wood chips	10/25/2021
CUSTOMER FUEL TREATMENT	OUTS	9.66	Eastern Regional Landfill	Wood chips	10/12/2021
CUSTOMER FUEL TREATMENT	RK	108.36	Eastern Regional Landfill	Wood chips	12/14/2021
CUSTOMER FUEL TREATMENT	RK	2	Neighborhood Firewood	Firewood	12/14/2021
CALDOR FIRE BIOMASS	OUTS	14.2	South Tahoe Refuse	Compost/ mulch	9/22/2021
CUSTOMER FUEL TREATMENT	RK	8	Neighborhood Firewood	Firewood	12/21/2021
HOBART PROJECT	BORDGES	1090.35		Decked for transport	12/31/2021

The Fuel Reduction and Wood Management Program was implemented through special projects in locations where Routine Work VM activities created slash and woody material build-up, causing customer complaints and reduction of tree removal agreements. Property owners, hesitant to have additional woody material generated on site, are generally reluctant to agree to tree removal. However, Liberty has implemented targeted fuel reduction projects with great success, achieving clearances that routine scheduling and equipment limitations would not otherwise accomplish.

Liberty piloted a project in 2021 in the Highlands HOA neighborhood to develop a coordinated effort between routine and special projects. This project aimed to reduce fuel created by vegetation maintenance and provide support to the local fire agency. This effort resulted in more than doubling the number of tree removals permissioned by routine allowing for much greater clearances in the neighborhood and significantly reducing future maintenance by removing trees out of the trim cycle. Liberty worked closely with the local Forest Fuels Coordinator to provide additional resources supporting the North Tahoe Fire Protection District's ("NTFPD") chipping program by removing debris homeowners stacked at the curb. As an additional fuel reduction effort, Liberty's tree contractors removed any woody debris—not related to line clearance work—up to 10" in diameter in support of NTFPD's residential curbside chipping program.

Liberty partners with local, state, and federal agencies and other larger landowners throughout its service area to collaborate on projects that will reduce fuel loads. Liberty has engaged with the California Tahoe Conservancy ("CTC") to reduce and remove wood and fuels left over from VM activity from parcels owned by the CTC in the Tahoe Basin. Liberty routinely conducts vegetation management work along power lines to remove identified hazards. Removal of dead trees or other hazards sometimes results in a significant amount of wood left on site. In cooperation with the CTC, logs from tree removals are cut into firewood lengths and staged in an accessible location for pickup. These locations are reported back to the CTC to advertise to the public for free firewood collection with a fuelwood permit. Liberty bucked fifty-nine trees into firewood lengths on thirty CTC lots in 2021. Firewood pickup locations can be found here: https://tahoecons.maps.arcgis.com/apps/MapTools/index.html?appid=7227479675664d119620b9ff5494a061

Meyers Substation Fuel Management Project: Building on an effort that began in 2020 to manage wildfire risk posed by vegetation surrounding Liberty's substations, Liberty identified additional fuel reduction work that significantly expanded the defensible space around Meyers substation in 2021. Located in South Lake Tahoe, near a densely populated area in a Tier 3 zone, Meyers substation is surrounded by conifers, a majority of which are Lodgepole pines, which have exhibited a failure pattern, particularly after storms. The additional work conducted reduced debris buildup from past tree work and from naturally caused down wood. Due to fall-in risk potential, high fire threat hazard location, proximity to a dense population, and importance of the substation, this location was chosen for additional Fuel Reduction.

Figure 7.3.5- 8: Meyers Substation Fuel Management Project

<u>Northstar Substation Fuel Management Project</u>: Liberty also implemented fuel management work at its Northstar substation in Truckee. Work was performed in cooperation with the landowner Northstar Resort and the local fire protection agency, Northstar Fire. Work was conducted to achieve appropriate tree spacing and reduction of ladder fuels through removal of dead, suppressed, and unhealthy trees, as well as selective thinning within 100 feet of the substation perimeter.

Figure 7.3.5- 9: Northstar Substation Fuel Management Project (Before/After)

Liberty projected to remove 2,100 tons of biomass from its system and completed 2,118.66 total tons of biomass removed through its portfolio of projects in 2021. Liberty's fuel management efforts in 2021 contributed to approximately 288.1 acres treated, 43.48 line miles treated, and participation from 581 landowners.

5. Future improvements to initiative

Liberty's local, state, and federal agency partners (CAL FIRE, Tahoe Regional Planning Agency, California Tahoe Conservancy, Tahoe Fire and Fuels Team, U.S. Forest Service, and local fire agencies) continue to be highly supportive partners and have increased their emphasis on the need to reduce forest fuel load that results from power line vegetation management. Liberty continues to work closely with these partners to develop best practices for an effective fuels management program that reduces both fire ignition risk and fire spread potential, while benefiting the local community and the environment.

7.3.5.6. Improvement of inspections

1. Risk to be mitigated

Managing vegetation threats begins with inspecting vegetation conditions, and the ability to implement appropriate controls is reliant on the resulting information gathered and provided. Improvement of inspections provides added certainty that vegetation requiring pruning or removal is properly identified with adequate time to mitigate the risk posed by the vegetation being assessed.

2. Initiative selection

In 2020, Liberty performed a comprehensive review of its VM program to identify areas of improvement and began updating its processes and procedures to meet program objectives. Liberty identified the frequency of vegetation inspections as an area of improvement. The subsequent implementation of comprehensive remote sensing vegetation inspections has greatly improved the ability to identify and remediate vegetation threats, reduce the time between inspections, and increase the ability of utility arborists and vegetation management professionals to make accurate and informed decisions. In turn, Liberty is equipped to make timely, data driven decisions when scheduling and prioritizing vegetation management projects.

3. Region prioritization

Liberty is continuing to focus on improving internal processes, workforce development, and identifying alternative methods of conducting inspections. When identified, improvements to inspections will be implemented throughout the Liberty system.

4. Progress on initiative

Prior to 2021, Liberty performed vegetation management inspections based on a three year cycle for detailed inspections. Since filing its 2020 Wildfire Mitigation Plan, Liberty has made significant progress in all areas of its vegetation management program to reduce the risk of wildfire. This progress is largely due to improvements made to vegetation inspections. The following outline provides improvements that have been implemented.

2020 Program Assessment and Strategy Development:

- Hired a vegetation management consultant to perform a comprehensive program assessment and identify areas in which to improve;
- Produced a new set of documents detailing processes and procedures for conducting vegetation inspections and implementing work;
- Piloted LiDAR technology as a new inspection protocol;
- Eliminated reliance on cycle-based vegetation inspections and developed a new vegetation management strategy to identify and mitigate vegetation related risk.

2021 Implementation of New Strategy:

- Coordinated with contracted vegetation inspectors to implement updated processes and procedures, monitor progress, and identify unresolved gaps;
- Performed vegetation inspections using remote sensing technology for the entire service territory;
- Secured contract for qualified arborists to perform Quality Assurance and Quality Control Inspections of vegetation management activities including vegetation inspections and work planning.

5. Future improvements to initiative

As the need for high quality vegetation management inspectors increases, the utility vegetation management industry is challenged to find adequate resources to meet program goals. While adequate staffing levels are paramount to a successful program, Liberty continues to invest in the use technology, professional development, and training to improve both the quantity and quality of vegetation inspections in order to meet program objectives. Liberty will continue implementing innovative solutions to better address the need for successful vegetation inspections.

The development of its LiDAR inspection program and its expansion to an annual inspection of 100% of the system has been a significant addition to Liberty's vegetation inspection methods. In addition to using LiDAR data for identifying vegetation conditions needing remediation, Liberty will expand the use of this data in the future to evaluate performance of inspections and vegetation management projects.

Future improvements will continue to focus on improving the quality of inspections through additional training of vegetation inspectors, monitoring progress and effectiveness with QA/QC processes, and incorporating additional technology into the program. Liberty is evaluating the use of artificial intelligence and machine learning with data collected from vegetation inspections and additional data sources to drive continuous improvement of the vegetation management program.

7.3.5.7. Remote sensing inspections of vegetation around distribution electric lines and equipment

Since filing its 2020 WMP, Liberty has been adopting the use of LiDAR inspections of vegetation to augment its VM program and reduce wildfire risk. These inspections have allowed Liberty to quickly transition to inspecting vegetation around high voltage lines and equipment on an annual basis. The unique geography of Liberty's service area lends itself well to remote sensing technology, which is leading Liberty to evaluate additional use cases for incorporating the technology into its vegetation maintenance strategy.

1. Risk to be mitigated

The ability of LiDAR to provide measurements of the distance between vegetation and overhead conductors with a high degree of accuracy makes it a useful tool in detecting locations where tree pruning, or removal may be necessary. LiDAR acquisition for vegetation analytics is typically conducted by fixed wing aircraft, which allows for quicker inspection of large areas than can be accomplished with ground-based patrols and expedites the process for achieving and maintaining adequate clearances around electric lines and equipment described in Section 7.3.5.20. The data provided by LiDAR inspections of vegetation around electric lines and equipment provides a detailed analysis of the vegetation conditions at the time data is acquired. In addition to regulatory compliance with G.O. 95 Rule 35 and Public Resources Code Section 4293, remote sensing can be used to determine where to focus resources when mitigating hazard trees within the Utility Strike Zone.

2. Initiative selection

From 2011 until 2020 Liberty had been managing vegetation using a cycle-based approach for vegetation inspection and maintenance activities. Third party assessments of Liberty's VM program were performed during that time to evaluate the workload and resource requirements and gather other information to make recommendations to improve program effectiveness. A three year maintenance cycle was consistently recommended as the optimal approach. Based on predominant species and growth rates, a three year cycle would be adequate for most of the vegetation encountered. Several variables may affect project timelines and, due to factors unique to Liberty, a three year cycle was not achieved. A 2018 analysis of maintenance history determined Liberty was completing work at a pace that equated to a seven point three (7.3) year maintenance cycle. In 2020, the Wildfire Safety Division recognized a deficiency in Liberty's VM program and Liberty performed a root cause analysis to identify why the previous practices failed to achieve desired results. Vegetation management program assessments traditionally are focused on determining an appropriate maintenance cycle and cost drivers impacting the ability to achieve the optimal cycle. A significant factor for Liberty that was not being resolved is the amount of time it takes to inspect circuits due to the topography and land ownership coupled with a shortened work season. The rugged terrain makes for challenging and time consuming inspections when using traditional ground based methods, and the approval process for vegetation projects can take up to a year after a detailed inspection is completed. Ultimately, it was determined that the inspection method needed to change in order to reduce the time between line clearance maintenance, and LiDAR is the most feasible method for Liberty to increase inspection frequency. Liberty is fully integrating LiDAR into its management practices to effectively manage the threat of vegetation growing into facilities and is looking to incorporate other technologies to develop more solutions to manage vegetation based on current conditions. Added value is will be attained by inputting remote sensing data into risk models for predictive analysis, work prioritization, and risk based decision-making.

3. Region prioritization

Liberty performs annual LiDAR inspections of vegetation around 100% of its electrical lines. Implementation is prioritized based on conditions observed at the time of inspection and the Vegetation Threat Procedure.

4. Progress on initiative

After completing LiDAR inspections of half of the system in 2020, Liberty completed an inspection of vegetation along the entirety of its overhead primary distribution and transmission system in 2021. Liberty is in the process of utilizing the data to locate and complete work necessary to achieve and maintain adequate clearances around the electrical lines and equipment.

An analysis of the changes detected by LiDAR from data collected in 2020 compared with 2021 is being used to evaluate program effectiveness. The initial results are positive and show a 21% reduction in the number of locations where work is required. An overall decrease in future vegetation encroachment threats is supported by an 8% reduction in the number of trees approaching the maintenance clearance zone. As Liberty continues utilizing LiDAR to manage vegetation on the entire system, it is expected encroachment threats will continue to decrease and eventually remain static given the same processes currently in place.

Table 7.3.5- 5: Trees by Clearance Zone

Clearance Zone	2020	2021	Change
Within maintenance clearance zone	966	655	-311
Approaching maintenance clearance zone	23,130	21,198	-1,932

Table 7.3.5- 6: Trees per Span

Trees Per Span	2020	2021	Change
0 Trees	6,099	6,511	412
1 Tree	1,517	1,260	-257
2-5 Trees	793	653	-140
6-10 Trees	23	8	-15
>10 Trees	2	2	0

Figure 7.3.5- 10: Liberty 2020 VM Lidar Tree Counts per Span

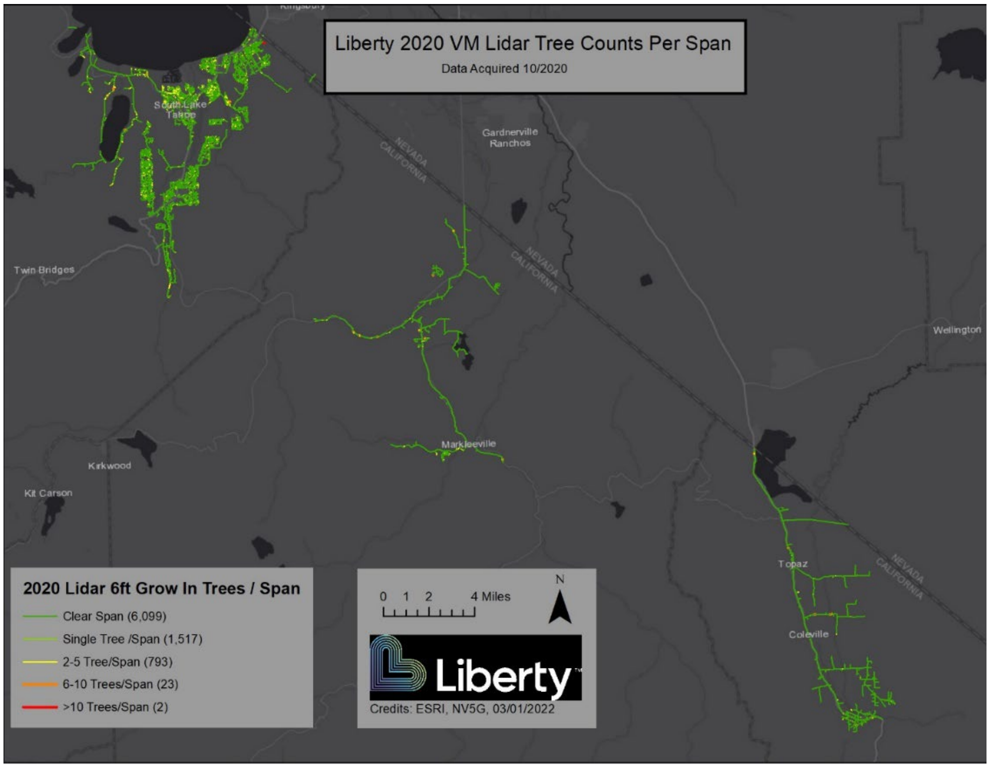


Figure 7.3.5- 11: Liberty 2021 VM Lidar Tree Counts per Span

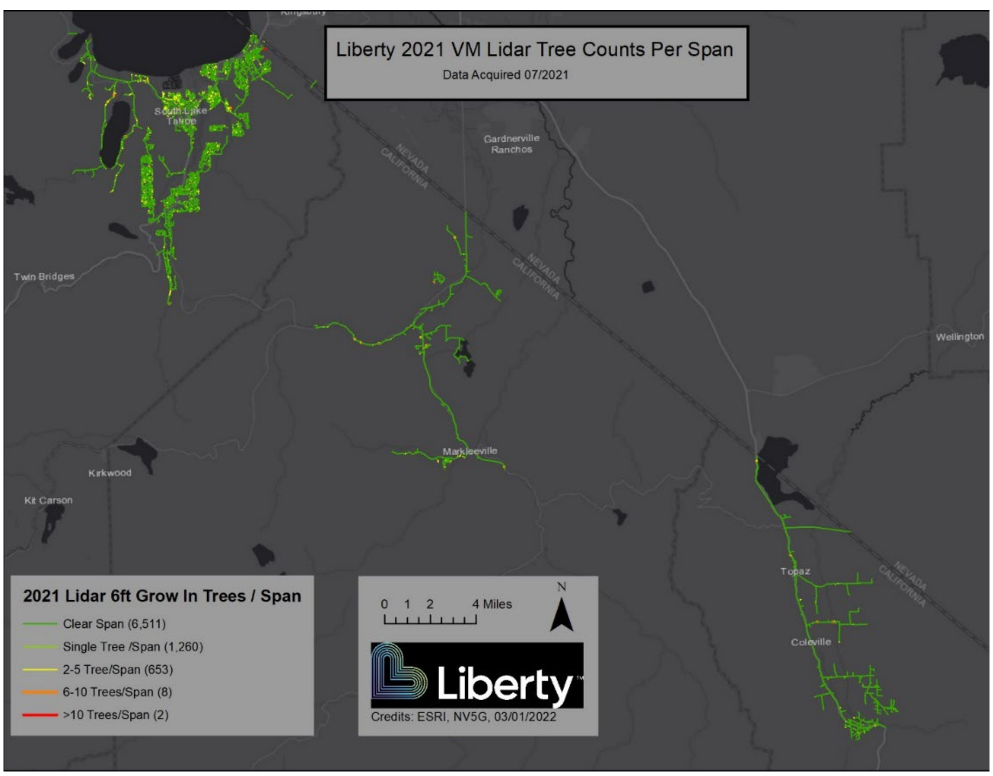
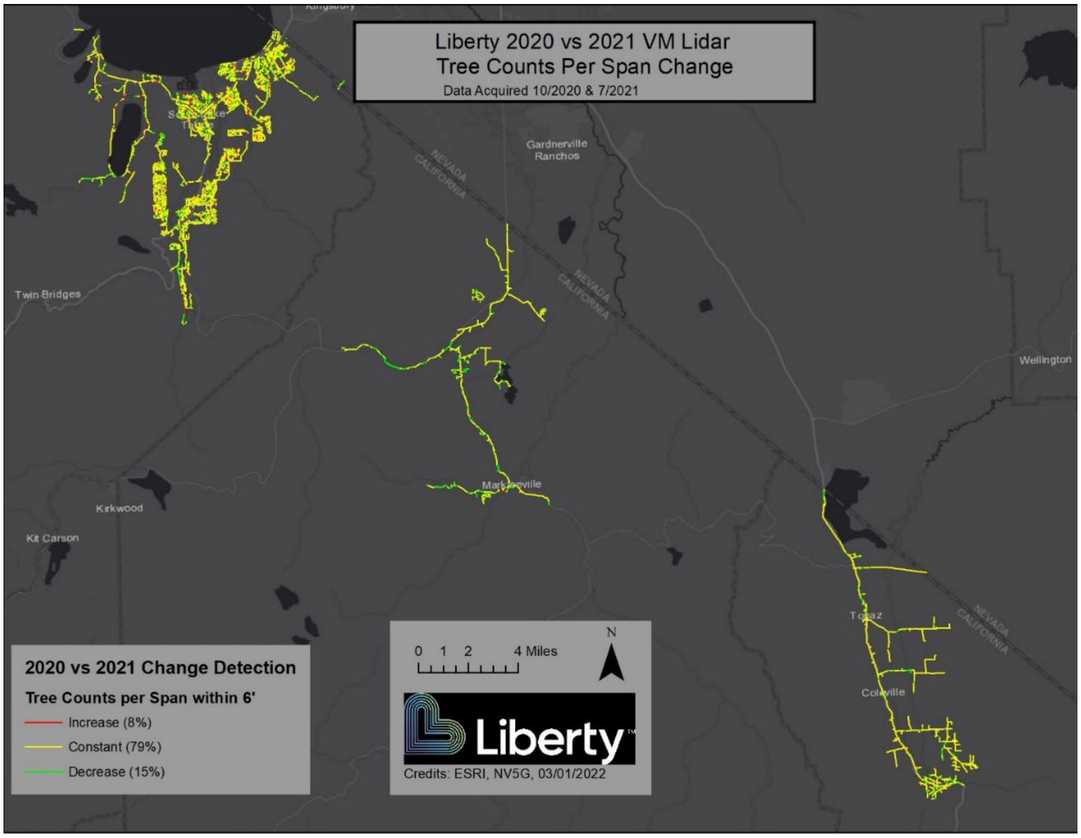


Figure 7.3.5- 12: Liberty 2020 vs 2021 VM Lidar Tree Counts per Span Change



5. Future improvements to initiative

Beyond using LiDAR for managing vegetation to conductor clearances, Liberty is evaluating how remote sensing can be implemented to enhance how hazard trees capable of striking facilities are identified and mitigated.

To evaluate remote sensing inspections for remediating trees with strike potential, Liberty is piloting the use of imagery that has been collected along with the LiDAR to perform tree health analysis. The purpose of this project is to determine how well remote sensing data can categorize areas where tree health is in decline along Liberty's transmission and distribution system. This analysis will be completed within Q2 of 2022, and Liberty will begin testing the data for incorporating into inspection processes in Q3 and Q4 of 2022. If successful, the data can be used to gain efficiencies with the identification, planning, inspection and removal of dead and dying trees that are potential hazards.

7.3.5.8. Remote sensing inspections of vegetation around transmission electric lines and equipment

Liberty's LiDAR inspections of vegetation around transmission electric lines and equipment do not differ from that for distribution electric lines and equipment. See Section 7.3.5.7.

7.3.5.9. Other discretionary inspection of vegetation around distribution electric lines and equipment, beyond inspections mandated by rules and regulations

Although Liberty does not currently have a specific applicable WMP initiative, the work performed in Section 7.3.5.2, 7.3.5.7, and 7.3.5.11 supports the effective inspections of distribution facilities.

7.3.5.10. Other discretionary inspection of vegetation around transmission electric lines and equipment, beyond inspections mandated by rules and regulations

Although Liberty does not currently have a specific applicable WMP initiative,, the work performed in Section 7.3.5.3, 7.3.5.8, and 7.3.5.12 support effective inspections of transmission facilities.

7.3.5.11. Patrol inspections of vegetation around distribution electric lines and equipment

Liberty performs inspections of vegetation along utility rights-of-way to identify obvious hazards. These inspections are focused on the removal of dead and dying trees within and adjacent to the right-of-way.

1. Risk to be mitigated

Patrol inspections of vegetation around electric lines and equipment are performed to identify dead and dying trees with the potential to strike electric facilities. During patrol inspections, trees are also evaluated for compliance with regulated clearance distances between vegetation and conductors per G.O. 95 Rule 35 and Public Resources Code Section 4293.

2. Initiative selection

Due to the nature of increasing tree mortality within its service territory, Liberty has identified the need to implement accelerated inspections for dead and dying trees along its system. Patrol inspections are typically performed by completing a Level 1: Limited Visual Assessment per ANSI A300 (Part 9) Tree Risk Assessment and application of Liberty's Hazard Tree Management Plan to identify dead and dying trees capable of striking electrical infrastructure.

3. Region prioritization

Several factors are taken into consideration when planning and prioritizing patrol inspections of vegetation around distribution electric lines and equipment. These factors include vegetation density, maintenance history, regional fire risk rating based on CPUC fire threat areas and Liberty fire risk polygons, customer tree inspection requests, observations from field employees and contractors, and vegetation caused outages. Emergency pruning or removal is performed when a tree poses an imminent threat to the electrical facilities.

4. Progress on initiative

Liberty's patrol inspections are performed primarily by a contract workforce of pre-inspectors trained to identify obvious hazards to Liberty infrastructure. In its 2021 WMP, Liberty planned to perform patrol inspections of vegetation around electric lines and equipment along a total of 150 miles of electrical lines and equipment. Liberty exceeded its plan by completing patrol inspections along approximately 179 miles of electrical lines and equipment.

5. Future improvements to initiative

Liberty's patrol inspections have been successful in mitigating the risk posed by dead and dying trees. Liberty will continue to perform these inspections to maintain reliability and safe operation of its electrical assets. Liberty is exploring the utilization of tree health analysis and tree strike potential acquired through LiDAR inspections. This process would contribute to further risk prioritization by informing Liberty of exact locations effected by tree mortality along its lines.

7.3.5.12. Patrol inspections of vegetation around transmission electric lines and equipment

Liberty's patrol inspections of vegetation around transmission electric lines and equipment do not differ from that for distribution electric lines and equipment. Refer to Section 7.3.5.11.

7.3.5.13. Quality assurance / quality control of vegetation management

In 2021 Liberty implemented a formalized QA/QC Program applicable to both vegetation inspections and vegetation management work conducted on private, federal, and agency land. The QA/QC Program provides Vegetation Management program oversight to provide reasonable assurance that vegetation inspection and maintenance work is being effectively performed.

The QA/QC Program is aligned with Liberty's Post Work Verification Procedure (VM-04) which outlines strategies for performing quality control inspections on the yearly workload. This is completed through statistical sampling and appropriate sample sizes to gauge acceptable quality levels (AQL) and conformance levels (CL). The procedure includes personnel qualification requirements, sampling methodology, sample size by priority, process assessment (QA), results evaluation (QC), acceptable quality level (AQL) and conformance level (CL), description of post work verification (*i.e.*, desktop review, field review), and types of QC inspections (*i.e.*, pre-inspections, tree pruning and removal, hazard trees, pole brushing, reporting accuracy, inventory reconciliation).

Table 7.3.5- 7: Sample Size (percentage) and Units

Work Type	Category	Annual Circuit Miles	Annual Hazard Trees	Annual Poles	Statistical Sampling		
					CL/MoE	%	Units
Completed Tree Work	T and D	701	-	-	99/7	33	228 Miles
Detailed Pre-Inspection	T and D	233	-	-	N/A	33	77 Miles
Hazard Tree Work[23]	T and D	-	2,500	-	99/5	21	524 Trees
Pole Brushing	T and D	-	-	4,859	99/5	12	584 Poles

1. Risk to be mitigated

The quality and effectiveness of its vegetation inspections and vegetation management work performed by its contractors is Liberty's utmost priority to help mitigate the risk of wildfires in its service territory. In order to mitigate this risk, various QC inspections are conducted during different phases of vegetation management work.

Tree Pruning and Removal QC Inspections:

- Ensure the Maintenance Clearance Distance (MCD) was achieved or work was completed as otherwise described in the work prescription
- Slash and debris removal was satisfactory as required by Liberty's specification and applicable regulations
- Complete and accurate inventory (*e.g.*, species, location, all other attributes as required)
- Pruning was completed per ANSI standard

[23] Estimate only. Hazard Tree Work can vary significantly each year depending on various field conditions.

Detailed Pre-inspection QC Inspections:

- Site location and access information are documented and accurate
- Complete and accurate inventory (*e.g.*, species, all other attributes as required)
- Appropriate Work Categories are assigned for Pruning, Removal, and Facility Protect (see Paragraph 'a' below)
- Permission is secured, as required
- Ensure MCD was prescribed
- If unable to secure MCD prescription, a description of why (*e.g.*, tree structure, past pruning practices, property owner request, etc.) is provided along with a description of what clearances are to be obtained
- Description of slash and debris handling was provided

Hazard Tree QC Inspections:

- Prescription was completed (*i.e.*, monitor, facility protect, remove)
- Slash and debris removal was satisfactory as required by Liberty's specification and applicable regulations
- Mitigation did not adversely impact other trees (*e.g.*, adjacent trees exposed to windthrow, etc.)
- Site conditions are stable after the completion of work

Pole Brushing QC Inspections:

- Work was completed as required by Public Resource Code (PRC) 4292
- Slash and debris removal was satisfactory as required by Liberty's specification and applicable regulations
- ANSI standard was met if pruning was required

2. Initiative selection

Liberty has implemented a Post Work Verification Procedure (VM-04), which is applicable to both vegetation inspections and vegetation management work that is conducted on local, federal, and state agency land. This procedure contains both QA and QC components. The purpose of the procedure is to define the program oversight requirements used to provide reasonable assurance that Liberty is meeting the applicable requirements related to vegetation management. The oversight contained in the procedure is intended to provide several levels of defense-in-depth strategy in order to provide reasonable assurance that inspection and maintenance work is being effectively performed.

3. Region prioritization

QA/QC Inspections will be performed in higher percentages in Tier 3 and Tier 2 HFTD with a smaller percentage being performed in non-HFTD areas. Tier 3 and Tier 2 HFTDs account for approximately 92 percent of Liberty's service territory.

4. Progress on initiative

Liberty began its VM QC inspections in July of 2021 and implemented them for five of eight targeted projects. The three incomplete projects started in late 2021 and will be completed in 2022.

Liberty's QC inspections were performed on 100% of the line miles for each VMQC project. This process allows for pre-inspection and work entry, completed tree work, hazard tree and pole brushing work to be evaluated simultaneously during QC inspection patrols. QC inspections occurred on approximately 146 line miles in 2021.

Table 7.3.5- 8: VM QC Projects

Project Status	Circuit	Start Date	Completed Date	# of Tree Records	# of Records Assessed	# of Hazard Trees	% Completed	# of Added Trees
Completed	Portola 31	07-19-2021	8-11-2021	859	859	12	100%	13
Completed	Tahoe City 5201	08-16-2021	9-22-2021	2,254	2,254	111	100%	19
Completed	Meyers 3500	09-21-2021	10-11-2021	55	55	12	100%	59
Completed	Meyers 3200	09-22-2021	10-14-2021	148	148	51	100%	72
Completed	Stateline 3101	10-13-2021	11-18-2021	304	304	61	100%	35
Pending	Topaz 1261	10-13-2021	Projected 2/1/2022	270	211	66	78%	12
Pending	Tahoe City 7300 Section 1	12-07-2021	Projected 2/1/2022	629	135	30	21%	3
Pending	Muller 1296 Section 5	12-08-2021	Projected 2/1/2022	534	144	18	27%	1
Total				**5,053**	**4,110**	**361**		**214**

Table 7.3.5- 9: Pole Brushing QC Projects

Project Status	Circuit	Start Date	Completed Date	# of Poles	# of Poles Reviewed	% Completed
Completed	Tahoe City 5201	09-08-2021	09-23-2021	338	338	100%
Completed	Meyers 3200	09-22-2021	10-06-2021	56	56	100%
Completed	Meyers 3500	09-22-2021	10-04-2021	198	198	100%
Pending	Topaz 1261	10-12-2021		345	337	98%
Completed	Stateline 3101	10-19-2021	10-27-2021	21	21	100%
Total				**958**	**950**	

5. Future improvements to initiative

Liberty reviews VM QC inspection results and provides recommendations to VM contractors as needed. In 2022, Liberty will improve its utilization of the data and provide additional feedback of VM work being conducted on the system by various VM contractors. Liberty expects continued process improvement will occur over the next 2 years as the program matures and intends to develop training for employees and contractors to improve quality based on results from the program.

7.3.5.14. Recruiting and training of vegetation management personnel

Appropriate staffing levels and properly trained staff are the key to any organization's success. The organization must be sustainable, meaning it is designed with adequate resources that have the appropriate capabilities and training, and the ongoing funding is appropriate. The short and long-term effectiveness of any VM program can be greatly influenced by staffing and funding decisions. In order to determine staffing requirements, managers must first understand the regulatory requirements of the program and understand the work that must be completed to comply with those requirements. Liberty has been proactive in acquiring and developing trained internal VM staff and has used historical data in order to assess the number of Liberty employees necessary to implement the VM program. Although this historical data may have been enough in years past, the vegetation management requirements have changed significantly in recent years.

In order to help expand the available vegetation management professionals, Liberty supports the development of utility vegetation management training such as that offered by the University of Wisconsin, Stevens Point. This is a two-year UVM Professional Development Certificate Program aimed at increasing the personnel available to staff utility VM programs and perform vegetation management inspection work. If possible, Liberty will take advantage of those graduates in the future. Additionally, Liberty supports the 5-week tree worker training program at Butte College in Oroville California, which is intended to develop and support individuals looking to make a transition to the utility tree worker industry.

Liberty continually seeks opportunities to host field trainings, benchmarking and tailboards on utility arboriculture topics among VM groups to align on industry practices and obtain continuing education units (CEU) to keep professional certifications in good standing.

1. Risk to be mitigated

The quality of the vegetation management program depends on properly trained Liberty staff who direct and oversee contracted work to maintain adherence to standards and compliance with all regulations. To successfully implement a strategy that will effectively mitigate wildfire risk, Liberty relies heavily on contractors that perform inspections and tree clearing work to provide properly trained personnel in order to complete the assigned work in accordance with Liberty's specifications.

2. Initiative selection

Liberty has increased its pace and scale of VM work since filing the 2020 WMP with LiDAR inspections and the development of three additional initiatives: quality control inspections, fuel management, and efforts to reduce community and environmental impacts.

Liberty recognized that the volume of work would outpace the ability to successfully manage its implementation, and an assessment of the VM organization was initiated to determine an appropriate structure for program management. From the assessment, a staffing plan was developed to accommodate recent program growth.

Safety, compliance, and service reliability are the stated goals for the vegetation management program. In order to achieve these goals Liberty must employ properly trained personnel and contractors. Additionally, it is imperative that all internal personnel and contractors are trained on, and able to execute, Liberty's wildfire mitigation plan. The response to Section 5.4 provides a comprehensive overview of the minimum requirements for both internal personnel and the contracted workforce.

3. Region prioritization

Liberty's contract specifications describe minimum requirements for contract personnel. Liberty reviews contract personnel qualifications to remain in compliance with the stated requirements and works with vendors to assign personnel to appropriate tasks. This process is applied consistently throughout the Liberty service territory.

4. Progress on initiative

Liberty requires employees within the VM Department to hold professional credentials and to complete ongoing training necessary to maintain applicable certifications. Being a Certified Arborist by the International Society of Arboriculture (ISA) with three years of relevant experience is the minimum requirement to be employed by Liberty as System Arborists. Additional training and credentials beyond the minimum are encouraged to further the professional development of employees and to provide a well-trained, motivated workforce. In August 2021, Liberty completed an assessment of the quantity and quality of internal personnel in relation to the ability to achieve VM program objectives. While not the only method used, professional certifications and credentials are helpful in conducting a qualitative analysis of workforce competencies. Liberty employs a very qualified workforce with a high concentration of advanced credentials (Table 5.4- 1).Insufficient VM workforce was identified as the biggest threat to program success. Liberty took appropriate action and identified the staffing levels necessary to maintain program effectiveness. Liberty is currently filling the additional positions and once fully staffed, the VM Department will have doubled in size since filing Liberty's 2020 Wildfire Mitigation Plan.

Table 7.3.5- 10: VM Credentials or Certifications

Applicable Credential or Certification	2021 Liberty Utility Arborists with Credential	
ISA Certified Arborist	5	100%
ISA Tree Risk Assessment Qualification	5	100%
ISA Certified Arborist Utility Specialist	3	60%
ISA Board Certified Master Arborist	1	20%
Utility Vegetation Management Certificate	1	20%

Liberty's program is effective at mitigating risk by ensuring adequately trained internal personnel and contractors manage and provide vegetation management services. Liberty will continue the use of its current processes and make adjustments, as necessary.

5. Future improvements to initiative

While Liberty requires and expects vegetation inspection and maintenance service contractors to provide adequate training, the VM Department vision is to be recognized as having a best-in-class utility vegetation management program. This requires Liberty to attract, retain, and develop best in class vegetation management personnel. With this in mind, Liberty will continue to support the development and expansion of utility vegetation management training such as that offered by the University of Wisconsin, Stevens Point, the 5-week tree worker training at Butte College in Oroville California, and other external professional development and training opportunities. In addition to encouraging participation in professional development offered by the utility vegetation management industry, Liberty is beginning to develop opportunities for personnel conducting vegetation management activities at Liberty. Depending on the subject and learning objectives, training will be developed by a combination of Liberty's highly qualified utility arborists and consultants who are subject matter experts in specific fields within utility vegetation management. Specific enhancements planned include both standard and specialized learning opportunities including:

- Electrical hazard awareness training
- Internal and external peer-to-peer training and knowledge sharing

- Liberty specific plant identification training for IVM program development
- Industry standards and best practices training for utility VM operations
- Communication training

7.3.5.15. Identification and remediation of "at-risk species"

Liberty has developed a Hazard Tree Management Plan (VM-03) for the purpose of identifying, documenting, and mitigating trees that are located within the Utility Strike Zone and are expected to pose a risk to electric facilities based on the tree's observed structural condition and site considerations. The plan includes an overview of tree risk associated with electric lines and equipment, inspection types, risk assessment levels, work priority levels, and mitigation actions.

Identification of at-risk species are typically performed by completing a Level 1: Limited Visual Assessment per ANSI A300 (Part 9) Tree Risk Assessment and in accordance with Liberty's Hazard Tree Management Plan. This is accomplished by conducting an assessment from one side of the tree (side nearest the electric facilities) and can be ground-based, vehicle-based, or aerial-based, as appropriate for the site conditions, type of infrastructure, and tree population being considered. A Level 1 assessment focuses on identifying obvious tree defects that are observable from the side of the tree nearest the electric facilities. If a condition of concern is identified during the Level 1 assessment, recommendations are developed regarding possible mitigation. If the Level 1 assessment cannot sufficiently determine the severity of the condition, a Level 2 assessment is conducted. Structural and site conditions that indicate a possible hazardous condition and could pose a risk to electric facilities are listed below. These are considered when performing a tree risk assessment.

Table 7.3.5- 11: Hazard Tree Attributes

Hazard Tree Attributes
Basal wound
Bleeding and/or resinous
Bulges and/or swellings
Cankers, including bleeding & gall rust
Cavities
Codominant or multiple stems from base or higher on trunk
Conks indicating heart rot, root rot, sap rot or canker rot
Cracks including shear
Dead branches and/or top
Dieback of twigs and/or branches
Embedded wires or cables
Excessive lean toward electric facilities or excessive bow
Fire damage
Foliage – off-color, flagging or loss
Hazard beam
History of limb failure(s) on tree
Included bark
Insect activity such as frass from termites, bark beetles or carpenter ants
Lightning damage

Hazard Tree Attributes
Live crown ratio below 30%
Mistletoe – dwarf or broad-leaf
Nesting holes – birds, mammals, insects
Dead palm fronds that can dislodge during high winds
Past poor pruning practices
Roots injured, exposed, undermined or uplifted
Seam
Species failure patterns
Unnatural or structurally unsound canopy weight distribution
Weak, unsound branch attachments

Table 7.3.5- 12: Hazard Site Attributes

Site Attributes
Areas known to be affected by introduced tree pathogens
Areas of recent clearing/new edge
Change in drainage
Change in grade
Construction – including trenching, paving or road construction
Cultural disturbance to landscape - natural or unnatural
Diseased center – dead tree in middle and dying trees around it
High stand density with single species composition
High Winds (fire watch)
History of failure(s) at site
History of repeated outages on circuit
Fire damage
Recent thinning or logging
Slope (by grade or percentage)
Soils prone to slides
Specific conditions like high winds
Storm damage

The tree composition in Liberty's service territory includes 24 different species. However, a select few make up the majority of the maintenance workload. Jeffrey pine, White Fir, Lodgepole Pine, and Quaking Aspen account for 90 percent of the trees along Liberty's distribution and transmission lines. Growth rate evaluations are done on all tree species during vegetation management inspections. Deciduous trees, particularly Siberian Elm and Black Cottonwood are prominent in the Antelope Valley, Sierra Valley and along stream environment zones throughout the service territory, exhibit very fast growth characteristics. Based on various tree characteristics and frequency along its lines, Liberty considers the following trees at-risk species:

- Jeffrey Pine
- White Fir
- Lodgepole Pine
- Quaking Aspen
- Siberian Elm
- Black Cottonwood

Once a tree has been identified as a hazard, there are various mitigation actions that can be taken based on the specific conditions at the site. These actions include the following:

- Complete tree removal: Complete tree removals must meet one of the following criteria:
  - The distance between the tree and Liberty's lines or facilities is equal to or less than the height of the tree and the Facility Protect mitigation (see below) is not feasible.
  - The tree is expected to pose a risk to electric facilities and shows characteristics that make the tree, or parts thereof, unstable, and the Facility Protect mitigation is not feasible.
- Facility protect: In some instances, a complete tree removal may not be required to mitigate the risk the tree poses to electric facilities. If appropriate conditions exist, portions of a tree can be pruned or removed to mitigate the risk. The hazard condition is not caused by or exacerbated by its site considerations.
- Monitoring: Assessed trees may be monitored when they are considered stable and are not expected to pose a risk to electric facilities in the foreseeable future but show signs of emerging hazard tree attributes or changing site considerations.
- Property owner – contractor assist: Only specially-trained and certified tree crews can work near high-voltage electric facilities. Property owners who hire their own tree workers to prune or remove trees near electric facilities should first notify Liberty. As part of the VM Program, Liberty will assess and remove portions of trees to a level that would allow workers that are not qualified to work within 10-feet of high-voltage electric facilities to remove or prune the remainder of the tree.

1. Risk to be mitigated

Tree and limb failures are common throughout the Liberty service territory. In order to reduce the risk of those failures contacting electric facilities, a process has been developed to identify, document and mitigate at-risk vegetation.

2. Initiative selection

As part of its Vegetation Management Program, Liberty manages thousands of trees within and along easements. Given the magnitude, Liberty cannot continuously assess every tree for possible defects. Even under the best circumstances and with the highest standard of care, tree failure cannot be predicted with 100% accuracy. Although Liberty is unable to reasonably foresee all tree failures all the time, by exercising good professional judgment and using a systematic approach, such as the one described in the Hazard Tree Management Plan, it is possible to significantly reduce the risk of tree failures that can damage electric facilities.

It is not possible to accurately identify or predict all trees that will fail, particularly during force majeure events. These events could include unforeseeable weather events or failures related to conditions that cannot be observed such as those related to root systems or the inner structure of the tree.

3. Region prioritization

Liberty has implemented a Vegetation Threat Procedure (VM-05) to identify methods of prioritization for vegetation threats discovered along electric lines and equipment through the implementation of its vegetation inspection programs. The Vegetation Threat Procedure prioritizes vegetation threats to be mitigated based on observed vegetation and surrounding environmental conditions. Although there is no region prioritization, Liberty may perform separate pre-fire season hazard tree inspections in designated Public Resource Code areas, Extreme (Tier 3) and Very High (Tier 2) fire areas as needed.

4. Progress on initiative

Table 7.3.5- 13: Vegetation Threat Mitigation Tree Work (2016-2021)

Year	Pruning	Removing	Total	Removal Rate	Overall Increase
2016	1,327	1,850	3,176	58%	
2017	1,990	2,482	4,472	56%	41%
2018	2,984	3,626	6,610	55%	48%
2019	5,870	5,185	11,056	47%	67%
2020	7,052	6,590	13,642	48%	23%
2021	7,820	6,537	14,537	46%	5%

5. Future improvements to initiative

None contemplated at this time.

7.3.5.16. Removal and remediation of trees with strike potential to electric lines and equipment

Mitigation of trees with the potential to strike electric lines and equipment are addressed in Section 7.3.5.15.

7.3.5.17. Substation inspections

Although Liberty does not currently have a specific applicable WMP initiative,, the inspections performed in Sections 7.3.5.2, 7.3.5.3, 7.3.5.11, and 7.3.5.12 support vegetation management work surrounding substations.

7.3.5.18. Substation vegetation management

Liberty's vegetation management work within the substation footprint is cleared on an as-needed basis using herbicide, pre-emergent and hand treatments. Although Liberty does not currently have a specific applicable WMP initiative,, the inspections performed in Sections 7.3.5.2, 7.3.5.3, 7.3.5.11, and 7.3.5.12 support vegetation management work surrounding substations.

7.3.5.19. Vegetation management system

In 2021, Liberty began preparing for an upgrade to its enterprise GIS program with plans for integrating operations and maintenance activities with all other business processes. The Vegetation Management System (VMS), where the vegetation inspection and maintenance data are stored, will need to be reconfigured to integrate with the new enterprise system. The VMS manages tree work inventories and workloads. The VMS also tracks circuit inspections, notification and tree work progress, provides work orders, notification letters and report generating functions, retains historical inspection and tree work data, and has a variety of query options to specify select tree inventories as needed (*i.e.*, routine circuit work on Federal lands for a specific inspection year or a random sample for quality control or assurance audits).

1. Risk to be mitigated

There is an inherent challenge to assign vegetation management work, track work progress, audit completed work, and re-assign work that is needed in the future. In order to meet this challenge, Liberty has implemented the Vegetation Management System throughout its footprint.

2. Initiative selection

Trees are inventoried if a specific tree requires remediation for the current inspection; therefore, a new tree is only added to the inventory in VMS if it is being listed for tree work. Every tree inventoried on the system is assigned its own tree ID number. If a tree that has been worked in the past requires work again, that specific tree record is updated to create a new work order and inspection record for the current inspection taking place, but the unique tree ID number for that tree does not change. Past work orders and inspection records for that tree are retained. During the inspection process, trees not requiring work are not inventoried and/or updated. Photographs, tree work authorization forms, and other documents associated with specific trees can be linked to the tree records through local network drives. Each individual tree is also assigned a status drop-down in order to track notifications, project progress, and tree work completion. Upon receipt of signed and completed work requests, an individual tree records status is changed to a completed status.

3. Region prioritization

The Vegetation Management System has been implemented throughout the Liberty system.

4. Progress on initiative

This initiative has been fully implemented.

5. Future improvements to initiative

Liberty is redefining the processes for data collection and is implementing workflow management applications to accommodate the GIS upgrade. Liberty's VM group plans to continue discussing improvements in tracking overall circuit work. Liberty has implemented additional software and data collection systems to manage and track project specific tree inventories as the program has evolved. Liberty will continue to evaluate feasibility and effectiveness of alternative systems used to manage increasing workloads, tree inventories, and program data. Liberty will continue to explore emerging technologies to improve work process efficiencies and reporting functionality.

7.3.5.20. Vegetation management to achieve clearances around electric lines and equipment

Liberty's VM program is designed to comply with all regulations including the clearances set forth in G.O. 95, Table 1, Public Resources Code (PRC) 4292, and PRC 4293. This is accomplished by performing comprehensive inspections as described in Sections 7.3.5.2, 7.3.5.3, 7.3.5.7, 7.3.5.8, 7.3.5.11, and 7.3.5.12 and performing the needed work as described in Liberty's plans and procedures.

1. Risk to be mitigated

Vegetation is a living organism and must be inspected/monitored on a regular basis to comply with stated regulations. In order to accomplish this, Liberty conducts annual inspections of its facilities in order to identify needed vegetation management work. Work performed as a result of these inspections meets the clearance recommendations set forth in Appendix E of G.O. 95, Rule 35 (14.4kV and 60kV – 12' to 15'; 120kV – 30'), PRC 4292, PRC 4293, and applicable California Code of Regulations - Title 14.

2. Initiative selection

Although not a static population, Liberty manages approximately 700,000 trees within and along its easements. Liberty continually monitors these trees using various inspection methods to comply with the clearance requirements set forth in applicable regulations. Liberty also performs pole brushing on approximately 5,000 poles throughout its service territory in order to comply with requirements set forth in applicable regulations.

3. Region prioritization

Liberty implements this inspection and clearing strategy throughout its system.

4. Progress on initiative

This initiative has been fully implemented.

5. Future improvements to initiative

Although there are currently no specific improvements needed or identified, Liberty continually evaluates its processes to meet the highest level of compliance with all mandated regulations.

7.3.5.21. Vegetation management activities post-fire

Liberty is currently managing post-fire mitigation work in accordance with Liberty's special use permit on Federal lands, and in accordance with Section 7.3.5.15 and Liberty's Hazard Tree Management Plan (VM-03) on other lands.

7.3.6. Grid Operations and Protocols

7.3.6.1. Automatic recloser operations

1. Risk to be mitigated

Primarily, the risk mitigated is wildfire, by de-energizing during end-of-line faults that substation relays may not pick up or take long to clear the fault. Having reclosers on the line in series allows for better clearing times for faults downstream of the line reclosers, thus better mitigating fire risk. As many as three devices in series have been employed on some of Liberty's longer distribution lines. Additionally, line reclosers can be used as smart switches to more rapidly isolate the faulted area and rapidly restore customers not in the faulted area where it is still safe to restore power. System automation also provides reliability benefits with the ability to quickly switch to isolate faults and restore load as much as possible. This is also known as FLISR (Fault Location, Isolation, and Service Restoration). It will be a valuable resource for more rapid service restoration after any PSPS event as well.

2. Initiative selection

Liberty's current system automation equipment uses traditional substation and line recloser relaying. One benefit is the ability to automatically reclose during non-high fire threat days, to clear temporary faults, and quickly restore power. The current system has the benefit of remote control and the ability to quickly change settings remotely, such as putting a device into one-shot (fire mode) during high fire threat days. For wildfire mitigation, the use of line reclosers places protective relaying closer to end-of-line faults, allowing the device to quickly clear faults that substation relaying may not pick up. Liberty is exploring the use of fast trip/one-shot (historically known as 'hot line tagging') during high fire threat days to limit energy to overhead faults.

Line recloser installation is an effective wildfire and PSPS mitigation measure. By placing line reclosers with high speed relaying devices out on distribution lines, line faults with lower fault current can be more rapidly detected and cleared. Adding DA will enable faults to be rapidly cleared and isolated for better fault location information and rapid system restoration, restoring power to customers in areas where re-energizing line is still safe. The relays also provide valuable information on the type of fault and fault current levels. The ability to remote control these devices will enable more rapid service restoration after any PSPS de-energization event.

3. Region prioritization

Liberty has made progress on implementation of new reclosers and aging recloser replacements in Tier 3 and Tier 2 areas within the Lake Tahoe basin. Liberty is expanding its recloser installations and replacements into its more remote Tier 2 areas going forward. Most of Liberty's substations currently have new technology relaying and with control and data acquisition (SCADA). Substations with older electromechanical relaying are scheduled for rebuild in future WMP cycles.

4. Progress on initiative

Two additional line reclosers were installed and operational in 2021, with plans for an additional four in 2022. Liberty plans to continue to replace or install at least three line reclosers per year going forward.

5. Future improvements to initiative

Liberty plans to continue installing new line reclosers to better sectionalize and have relaying devices closer to end-of-line to help detect low current faults. Liberty is planning to install four additional line reclosers in 2022 and to replace or install at least three line reclosers per year going forward. Additionally, Liberty is planning on a DA pilot program starting 2022. Liberty plans to house a DA controller at one of its substations and control multiple communication enabled reclosers and substation breakers. This allows for FLISR technology to be implemented on our system. It has the added benefit of more rapid restoration after a PSPS event.

7.3.6.2. Protective equipment and device settings

1. Risk to be mitigated

Primarily, the risk mitigated is ignitions. By more rapidly clearing a fault and limiting the energy or spark, the current that may cause a spark is greatly reduced. By utilizing faster clearing times, fault current is much more rapidly cleared, thus reducing the risk of an ignition for many fault types, such as wire down, wire slap, and most vegetation faults.

2. Initiative selection

As discussed previously, Liberty's current system automation equipment uses traditional substation and line recloser relaying. Recently, Liberty has explored the use of fast trip/one-shot (historically known as 'hot line tagging') during high fire threat days to limit energy to overhead faults and minimize chance of ignition without PSPS. However, this can lead to larger and longer outages. To address this, Liberty is starting to explore fault detection with communications to more quickly determine the location of the fault when using fast trips to mitigate a PSPS situation.

This initiative is low cost but very effective. It utilizes existing protective devices in the field and involves simply changing the settings, many of which are done remotely. All of Liberty's substation breakers and line reclosers can be placed into 'hot-line tag' and reduce the fault clearing time to as fast as possible. This is a great alternative in many cases to a PSPS should the conditions warrant.

3. Region prioritization

Liberty plans to use this initiative during high fire threat days in areas identified as significant risk for ignition. Liberty will also utilize this method to reduce PSPS events to the extent possible based on risk of ignition in the affected areas.

4. Progress on initiative

This initiative is already effectively in place with Liberty's existing protective devices in the field. It will only be enhanced by Liberty's programs to add more line reclosers and upgraded substation technology.

5. Future improvements to initiative

Liberty plans to continue installing new line reclosers to better sectionalize and have relaying devices closer to end-of-line to help detect low current faults. Liberty is planning to install four additional line reclosers in 2022 and to replace or install at least three line reclosers per year going forward. Also, Liberty has embarked on a collaborative research project with the University of Nevada, Reno to perform a study on better protective device coordination when utilizing fast curve technology.

7.3.6.3. Crew-accompanying ignition prevention and suppression resources and services

Refer to Section 7.3.6.4.

7.3.6.4. Personnel work procedures and training in conditions of elevated fire risk

1. Risk to be mitigated

Liberty has designated the type of work activities that may be performed in its service territory under certain FPI Operating Conditions (*e.g.*, low condition, moderate condition, high condition, very high condition, and Extreme or Red Flag Warning condition). As conditions increase in severity, activities that present an increased risk of ignition have additional mitigation requirements. Where risk cannot be mitigated, work activity will cease. Personnel work procedures and proper training help mitigate the risk of an ignition while performing at-risk activities that are necessary to maintain and operate the Liberty electric system.

The following summarizes the work activity guidelines for each of Liberty's Operating Conditions:

Low Fire Risk: As determined by the Wildfire Prevention Department, Low or "Normal" Fire Risk is defined as periods where the potential for wildfires and associated ignition risks are low but may sometimes still exist within Tier 2 or 3 of the HFTD. Some O&M activities may have stipulations and additional fire mitigation activities may be required. The Low Fire Risk status is the default operational state and the FPI is indicated as "Blue."

Moderate Fire Risk: As determined by the Wildfire Prevention Department, Moderate Fire Risk is defined as periods where the potential for wildfires and associated ignition risks are not elevated but still exist within Tier 2 or 3 of the HFTD. Some O&M activities may have stipulations and additional fire mitigation activities may be required. The FPI is indicated as "Green."

High Fire Risk: As determined by the Wildfire Prevention Department, High Fire Risk is defined as periods of increasing risk of wildfires and associated ignition risks within Tier 2 or 3 of the HFTD. Many O&M activities have stipulations and additional fire mitigation activities are sometimes required. The High Fire Risk status is indicated as "Yellow."

Very High Fire Risk: As determined by the Wildfire Prevention Department, Very High Fire Risk is defined as periods of increasing risk of wildfires and associated ignition risks within Tier 2 or 3 of the HFTD. Many O&M activities have stipulations and additional fire mitigation activities are required. The Very High Fire Risk status is indicated as "Orange."

Extreme Fire Risk: As determined by the Wildfire Prevention Department, Extreme Fire Risk is defined as periods of significant risk of wildfires and the associated ignition risks within Tier 2 or 3 of the HFTD. All O&M activities have stipulations, and significant fire mitigation activities are required. Most overhead work activities will cease, except where not performing the work would create a greater risk than doing so. In those cases where at-risk work needs to be performed, a Liberty Fire Safety Monitor or Leader is assigned, and additional mitigation steps are implemented. The Extreme Fire Risk status is indicated as "Red."

2. Initiative selection

The safety of Liberty's customers, personnel, and cooperating agencies are all considered during the development and subsequent refinements of Liberty's personnel work procedures and training. Wildfire presents a large risk to all these groups and these procedures help to greatly reduce the chance that Liberty's activities cause ignitions and that Liberty personnel are prepared in the event of a wildfire in an area in which they are working.

3. Region prioritization

Liberty's Fire Prevention Plan requires that all employees, contractors, and consultants that conduct activities in the wildland areas of the service territory receive this training on an annual basis. The training includes definitions of at-risk work, wildland areas, FPI, and a matrix that can be used to determine the minimum fire prevention requirements for at risk activities. Information is also provided related to working on, or adjacent to wildland fires, reporting wildland fires, and guidance for taking fire suppression action.

4. Progress on initiative

Liberty has refined and updated its FPI Operating Conditions since 2020 and plans to continue to conduct training on fire prevention and emergency actions at any ignition found. Liberty will continue refining procedures designed to prevent ignitions from Liberty equipment or activities throughout our service area.

5. Future improvements to initiative

Liberty's Wildfire Prevention Division continues to explore other opportunities to improve FPI Operating Conditions and safety training processes to train personnel to be prepared to work in elevated fire risk conditions. Procedures and training are reviewed annually, and feedback from attendees, other IOUs/agencies, and from public safety partners is incorporated into future training.

7.3.6.5. Protocols for PSPS re-energization

1. Risk to be mitigated

Primarily, the risk is long interruption of service to a variety of customer types, including medical baseline customers. Service restoration is unique for each emergency event and restoration prioritization is influenced by several factors including safety, accessibility, availability of repair parts, availability of personnel, etc. This element of the plan identifies general restoration prioritization guidelines but allows for the Incident Commander, or designee, to alter priorities according to the circumstances of the emergency and in coordination with essential load customers and government agencies.

2. Initiative selection

As outlined in Liberty's Corporate Emergency Management Plan ("CEMP") pursuant to G.O. 166, Liberty has developed a PSPS plan that supplements and enhances protocols for preparedness and service restoration in the event of a PSPS or other emergency. Liberty reviews the plan annually to bolster its preparedness plan to not only meet compliance standards for service restoration but to also reduce impacts of PSPS events on its customers. Liberty's Comprehensive Emergency Management Plan (CEMP) addresses the procedures for damage assessment (pg. 21) and restoration (pg. 22) that would be followed in the event of a wildfire. Refer to Attachment H: Liberty's CEMP.

3. Region prioritization

Restoration Guidelines include:

i. Restore radial transmission and substations;
ii. Restore distribution circuits with essential customers such as health care facilities, utilities, public safety, governmental facilities, and Green Cross customers;
iii. Restore circuits with the greatest number of customers;
iv. Restore primary taps, followed by secondary lines;
v. Restore individual services which are accessible and serviceable;
vi. Restore essential customers.

Below is the priority list of essential customers. Priority assumes circuits, equipment, and services are accessible and repairable.

i. Health care hospitals
   a. Primary care hospitals
ii. Utility Services/Districts
   a. Public Utility Districts
   b. Telecommunications
   c. Water/Water Treatment
   d. Pipeline
iii. Public safety agencies
   a. Public Safety Dispatch Centers
   b. Law enforcement facilities/holding facilities
   c. Fire operations facilities
   d. Transportation equipment and facilities
iv. Government facilities
v. Green Cross customers

4. Progress on initiative

Liberty has developed its PSPS plan and will review the plan annually and will make improvements if deemed necessary. Liberty plans to exercise its PSPS plan annually and incorporate lessons learned.

5. Future improvements to initiative

Liberty reviews the plan annually to bolster its preparedness plan to meet compliance standards for service restoration.

7.3.6.6. PSPS events and mitigation of PSPS impacts

1. Risk to be mitigated

Liberty's PSPS program is meant to be used a last resort wildfire mitigation. The decision to implement a PSPS is not taken lightly, which is why Liberty has invested heavily in the program. Developing thresholds, PSPS protocols and procedures, weather monitoring tools, community outreach efforts, CRC's, and training personnel are all part of these investments. As the program has progressed from 2019 to now, Liberty has greatly improved the level of preparedness needed to execute a PSPS and minimize the impacts to customers and remains dedicated to continued improvement.

2. Initiative selection

Liberty has not executed a PSPS event since the program was developed in 2019. However, Liberty has invested heavily in its PSPS program, including developing thresholds, PSPS protocols and procedures, weather monitoring tools, community outreach efforts, AFN Plans, CRC's, and training personnel.

3. Region prioritization

Liberty has established plans and protocols to support all of its customers during potential PSPS events, including its most vulnerable and MBL customers. Additionally, Liberty is working to develop PSPS risk zones within its service territory.

4. Progress on initiative

As the program has progressed from 2019 to now, Liberty has greatly improved the level of preparedness needed to execute a PSPS and minimize the impacts to customers.

5. Future improvements to initiative

Liberty remains dedicated to continued improvement of its PSPS program and mitigating the impacts to its customers of potential PSPS events. Refer to Sections 7.3.6.4, 7.3.6.5, 7.3.9.1, 7.3.9.2, 7.3.9.3 and Section 8 for more information on Liberty's PSPS program. Additionally, in February 2022, Liberty filed an application at the CPUC for a Customer Resiliency Program intended to provide customers, including MBL customers, with greater energy resiliency during PSPS and other hazardous events. Refer to Attachment B for additional information regarding Liberty's Customer Resiliency Program.

7.3.6.7. Stationed and on-call ignition prevention and suppression resources and services

Refer to Section 7.3.6.4.

7.3.7. Data Governance

7.3.7.1. Centralized repository for data

1. Risk to be mitigated

The efficiency and accuracy of data processing related to work performed is intended to provide safe and reliable business information to reduce the costs associated with field errors, delays, infrastructure vulnerabilities and miscommunication. Multiple copies of spreadsheets, out of date information and miscommunication can introduce risks when guiding decisions. The centralization of data creates an empowered workforce that can act quicker in the right places to provide safer, more reliable services.

2. Initiative selection

Relational and transactional data is a constantly changing process that challenges users to achieve accuracy and timeliness. The centralization of data sources requires appropriate systems and skillsets that can provide data integrity and security while providing appropriate access and tools to perform analysis. Liberty will advance this process of data sophistication to achieve a robust framework of integrated business intelligence and move towards dashboard capabilities for driving risk based decision-making. Liberty strives to empower its workforce with the most efficient methodologies it can provide to mitigate risk, lower costs and provide reliability in service.

3. Region prioritization

Continued centralization and sophistication of data systems will improve systems over the entire service territory with emphasis on Tier 3 and identified high fire risk areas.

4. Progress on initiative

The results of the full system survey asset inventory completed in 2020 provided the basis for an asset management system that can be used for prioritizing work based on wildfire risk modeling and fire risk maps and can enable Liberty to respond to infractions with increased speed, volume, and improved accuracy. Throughout 2021, Liberty continued to improve protocols and train its staff on digital field collection forms and integrating data sources that will assist Liberty to further leverage data governance upgrades and adoption of new technologies.

Liberty has three major software upgrades underway that will impact this initiative, including upgrades to its Geographic Information System ("GIS"), Outage Management System ("OMS"), and Responder database. In designing a solution that considers these major system upgrades and integrates with all current data sources, Liberty has initiated conversations and requests for information with consultants offering data analytics solutions.

5. Future improvements to initiative

Liberty's overall goal is to develop an integrated data management and reporting solution to improve data consistency and efficiencies internally and for the WMP reporting process. Liberty intends to leverage its centralized data repository framework to create a series of business information dashboards and cloud-based performance metric display pages.

Liberty continues to advance its usage of a centralized data storage and integrate relational data systems. While there is currently no centralized wildfire risk data repository, there are established databases maintained individually in silos that includes an outage incident reporting system (Responder), geographic information systems ("GIS"), Vegetation Management System database ("VMS"), and an initial asset database from the system-wide survey. Other risk-based decision-making data sources, such as environmental impacts, work planning and tracking using Reax fire map overlays, system hardening efforts, and overall systems analysis will improve with integration of data from all systems.

As Liberty moves forward with new methods of integration, analysis and reporting, Liberty's risk-based decision-making process will continue to add efficiency and sophistication. The platform supporting storage, processing and utilization of all Liberty proprietary and outside sourced data is expected to mature and standardize within the next two to three years. Liberty has established data sources providing a wealth of information that once summarized and integrated can be used for planning work efforts that fully leverage risk based decision-making. By compiling selected data from these data sources in a centralized location in real-time, information can be utilized by different groups, such as vegetation management, and coordinate regional inspections and repair work based on previously evaluated high risk areas. Liberty can also increasingly utilize this data framework for system hardening initiatives.

7.3.7.2. Collaborative research on utility ignition and/or wildfire

1. Risk to be mitigated

The primary risk to be mitigated is wildfire ignitions due to intermittent issues and high impedance faults. High Impedance Fault Detection ("HIFD") technology is well suited to detect faults that are high impedance in nature.

2. Initiative selection

HIFD is a collaborative research project between the University of Nevada, Reno ("UNR") and Liberty. This technology is well suited to detect faults that are high impedance in nature. It is believed that this technology will work particularly well in the Lake Tahoe Basin in light of the poor grounding conditions in the area. Liberty selected HIFD for its ability to clear high impedance faults. With the poor grounding in much of Liberty's territory, this technology seems well suited to clear faults rapidly before ignitions. Traditional protection measures have not performed well with these types of faults on poorly grounded networks.

3. Region prioritization

Region prioritization will be focused primarily in the Tier 3 region, moving out to Tier 2 if the technology is proven to reduce wildfire ignition risk.

4. Progress on initiative

Liberty plans to deploy HIFD in 2022. The HIFD settings produced by University of Nevada Reno will be installed into the protection relays feeding our piloted lines. Liberty will set these to alarm on a HIF and subsequently inspect.

5. Future improvements to initiative

For selected lines, Liberty will evaluate how much quicker high impedance faults are detected.

7.3.7.3. Documentation and disclosure of wildfire-related data and algorithms

Refer to Section 7.3.7.1.

7.3.7.4. Tracking and analysis of risk event data

Refer to Section 7.3.7.1.

7.3.8. Resource Allocation Methodology

7.3.8.1. Allocation methodology development and application

Refer to Section 7.3.7.1.

7.3.8.2. Risk reduction scenario development and analysis

Refer to Section 7.3.7.1.

7.3.8.3. Risk-spend-efficiency analysis – not to include PSPS

Refer to Section 4.3 and Section 7.1.

7.3.9. Emergency Planning and Operations

The emergency preparedness and response plans described in Liberty's WMP comply with Cal. Pub. Util. Code §§ 768.6, 8386. Specifically, the WMP complies with the following mandates:

- Sharing elements of vested interest of the WMP and emergency response plan with relevant cities and counties to provide input and feedback.
- Direction to routinely update and improve the WMP.
- Accounting of responsibilities of persons responsible for executing the WMP.
- Appropriate and feasible procedures for notifying customers that may be impacted.
- Plans to prepare for and restore service, including workforce mobilization.
- Plans for community outreach and public awareness before, during, and after a wildfire.
- Emergency communications that include plans to provide messages in English, Spanish, German, French, and Chinese (Mandarin and Cantonese). Languages prevalent in Liberty's service area are English and Spanish, based on United States Census data.
- Protocols for compliance with Commission reporting guidelines.

7.3.9.1. Adequate and trained workforce for service restoration

1. Risk to be mitigated

Primarily, the risk is long interruption of service to a variety of customer types, including medical baseline customers. Service restoration is unique to each emergency and restoration prioritization is influenced by several factors including safety, accessibility, availability of repair parts, and availability of personnel.

2. Initiative selection

Having an adequate and trained workforce is part of Liberty's normal operating procedures. Liberty employs a staff of qualified journeymen linemen in order to handle day-to-day activities as well as respond to emergencies. Liberty has addressed limitations in resource sufficiency through mutual aid agreements and if needed, can add additional entities in major emergencies through these agreements. Mutual assistance entities include NV Energy, Western Region Mutual Assistance Agreement ("WRMAA"), and the California Utilities Emergency Association ("CUEA"). Liberty is also in the process of adding additional qualified journeyman linemen to its workforce to better handle both day-to-day and emergency work. Liberty utilizes contract crews for some work and will utilize contractors for emergencies when necessary.

3. Region prioritization

Restoration guidelines include:

i. Restore radial transmission and substations;
ii. Restore distribution circuits with essential customers such as health care facilities, utilities, public safety governmental facilities, and Green Cross customers;
iii. Restore circuits with the greatest number of customers;
iv. Restore primary taps, followed by secondary lines;
v. Restore individual services which are accessible and serviceable;
vi. Restore essential customers.

Below is the priority list of essential customers. Priority assumes circuits, equipment, and services are accessible and repairable.

a. Health Care Hospitals
    a. Primary Care Hospitals
b. Utility Services/Districts
    a. Public Utility Districts
    b. Telecommunications
    c. Water/Water Treatment
    d. Pipeline
c. Public Safety Agencies
    a. Public Safety Dispatch Centers
    b. Law enforcement facilities/holding facilities
    c. Fire operations facilities
    d. Transportation equipment and facilities
d. Government facilities
e. Green Cross customers

4. Progress on initiative

Liberty has this plan in place.

5. Future improvements to initiative

Liberty is in the process of adding additional crew members to improve emergency restoration and normal day-to-day work.

7.3.9.2. Community outreach, public awareness, and communications efforts

1. Risk to be mitigated

Wildfires are a year-round threat in California. As a result, Liberty executes a robust, year-round communications and outreach effort to increase community resiliency to wildfires and educate customers and the public about PSPS and how to prepare for potential de-energization events. The goal of this effort is the increase awareness and community resiliency to wildfires and PSPS.

2. Initiative selection

Liberty conducts PSPS and wildfire-specific communications in three phases: before, during, and following an emergency event. Efforts before focus on immediate actions customers and the public can employ to remain safe, resilient and updated during the emergency. During the event, Liberty focuses on providing real-time awareness and updates about the event and how to remain safe. Following the event, Liberty focuses on transparency, from educating customers and the public on the impact of the event to soliciting customer feedback to improve communication efforts for any future event.

3. Region prioritization

Public education and communication efforts target Liberty's service territory with a particular focus on the areas that are most at risk of PSPS or wildfire (High Fire Threat District). Liberty also focuses on areas with an elevated percentage of at-risk customers, such as MBL and AFN customers.

4. Progress on initiative

Liberty's wildfire mitigation communications and public education initiative consists of direct and indirect engagement through community outreach materials and engagement campaigns. Materials produced over the course of the year are tailored to match Liberty's respective audience and phase. Additionally, communications and outreach efforts will be enhanced and adjusted to reflect feedback received and emerging best practices.

Prior to a potential event: In 2021, Liberty expanded its public education and outreach efforts associated with its wildfire mitigation plan. Safety and resiliency communications were part of a territory-wide public education campaign. These communications focused on personal preparedness and community resiliency. Also, in light of COVID-19 considerations, special emphasis was placed on digital outreach to engage customers on important emergency, wildfire, and PSPS information.

- Online town halls: As mentioned above, the COVID-19 pandemic altered how Liberty communicated with customers and the general public. Community-based virtual town halls were held to provide information about Liberty's local wildfire mitigation efforts, PSPS, and how to prepare and remain resilient through the events. Virtual town halls were advertised on Liberty's social media platforms and promoted via email communications. Liberty anticipates the continued need for virtual events; therefore, planning for future events will focus on garnering more participation in these community events.
- Community Newsletter outreach: Liberty continually looks for new ways to reach its customers. In 2021, Liberty continued its public education campaign through community-based newsletters and magazines. The purpose of the campaign was to promote personal preparedness during an emergency, wildfire, or PSPS. Liberty also provided PSPS messaging, including educational material on the factors that determine a PSPS and how Liberty would communicate to customers and community partners during a de-energization event.
- Digital communications: In 2021, Liberty launched a digital ad campaign specific to Wildfire Mitigation and PSPS preparation and awareness. Topics included defensible space, emergency preparedness, medical baseline program information, general PSPS information and preparation tips, communication of PSPS public workshops, and the importance of updating contact information in Liberty systems to enable PSPS and emergency notifications. Liberty anticipates the continued need for digital communications in 2022 and beyond.
- CBO outreach: Liberty engaged regional CBOs to help disseminate critical preparedness information. CBOs were provided with a digital toolkit, which included information about assistance programs, the MBL program, etc. Liberty has recently added two positions to expand CBO relationship networks and communications channels and plans to make further progress throughout 2022, including a bilingual Outreach Coordinator.

During an event: Liberty will execute standard communication protocols such as, but not limited to, customer notifications, media updates and situational awareness postings across social media channels. In addition, Liberty will activate a series of additional tactics to inform customers and the public about the latest developments during emergency, wildfire, and PSPS events.

During an event, Liberty will assign dedicated liaisons who are responsible for conveying real-time updates and outreach material to our public safety partners, elected officials, critical facilities and CBOs. Liberty will also employ standard communication channels to promote emergency service resources including, but not limited to social media channels, broadcast and print media, and the Liberty website. As part of its expanded outreach, Liberty will coordinate roadside changeable message signs with Caltrans throughout affected communities to keep impacted residents informed. These signs will be critically important to educate tourists in Liberty's service territory.

Liberty will disseminate detailed information on the emergency, wildfire, or PSPS event, including a list and maps of impacted communities, critical facilities, and estimated number of impacted customers and share it with local public safety partners and elected officials. Liberty facilitated daily workshops for both Public Safety Partners and customers during its potential PSPS event in September 2021 and intends on continuing this practice in 2022.

To expand its digital outreach, Liberty will distribute public service announcements ("PSAs") to read live on the airwaves and coordinate with CalOES to distribute wireless emergency alerts to impacted regions. The templates allow for the addition of real-time awareness details and provide referral to Liberty's social media platforms for additional safety information and updates.

Following an event: Communicating with customers and the public early and often is essential to the region's wildfire preparedness. Liberty engages in discussions and solicits feedback from its communities and stakeholders regarding proactive safety preparations, mitigation measures and community support strategies to reduce infrastructure-related ignitions and mitigate impacts of a wildfire or PSPS.

In 2021, Liberty reached out to customers through formal surveys to establish a baseline awareness of wildfire mitigation and PSPS-related messaging and communications at the beginning of wildfire season. At the end of the 2021 wildfire season, customers were again surveyed to measure the effectiveness of public education efforts and communications. Liberty will use the gathered feedback to evaluate, refine and improve customer and public education efforts for 2022 and follow a similar process in the coming years.

5. Future improvements to initiative

In 2022, Liberty plans to invest in improvements that enhance both wildfire safety and PSPS communications. As previously noted, these efforts include the expansion of the MBL and AFN campaign to better communicate with at-risk populations. The public education campaign will start earlier in the year and will work to expand the reach of communications within the service territory. Liberty reviewed survey results and assessed effectiveness of its communication campaign to implement an adjusted strategy for 2022

AFN identification and available resource communication will continue to be a focus in 2022. Liberty continues to work on modifications to its systems to allow and improve the recording of AFN customer categories and data beyond MBL customers. Supplemental to established surveys, Liberty plans to implement a survey effort with a focus on AFN customers to measure awareness of support and satisfaction with level of utility communication regarding PSPS preparedness and event updates.

Liberty will also continue to build partnerships with CBOs. Many of these organizations target at-risk communities and can help refine communications and further identify AFN populations within the territory.

7.3.9.3. Customer support in emergencies

1. Risk to be mitigated

Emergencies and wildfires can leave customers looking for support in many areas. Liberty provides assistance to those who are directly impacted. Customers eligible for the wildfire customer protections described below are those directly impacted by the wildfires and identified as such by Liberty or who have self-reported as being impacted. Directly impacted customers would include those without electric service or those needing to re-locate (either temporarily or permanently) due to wildfire damage.

2. Initiative selection

Liberty provides emergency residential and non-residential customer protections for wildfire victims, as ordered by the CPUC. Examples of protections include billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, and specific support for low income and MBL customers. The descriptions below reflect Liberty's customer protection measures during and after a wildfire or PSPS event:

- Outage reporting: Throughout the lifecycle of an adverse weather event, it is important that the customer is adequately informed and prepared at all times. Liberty utilizes a multi-channel approach for real-time situational awareness. After extreme weather conditions are forecasted and the National Weather Service issues a Red Flag Warning, Liberty begins to coordinate with local government agencies, community-based organizations, and public safety partners approximately 72 hours prior to the event. Communications are then initiated with customers via Everbridge, broadcast media and social media channels. These communications drive traffic to Liberty's social media and/or dedicated PSPS landing page for more information and real-time situation updates. As the event progresses, these notifications become more specific and targeted to customers as the situation warrants. Along with outage updates the channels listed above provide information related to wildfire safety, emergency preparedness, PSPS, and Community Resource Centers.
- Support for low-income and MBL customers: Refer to Attachment G: Liberty 2022 Plan to Support AFN Populations During PSPS for specific measures that Liberty has developed to support AFN customers during emergencies, including PSPS events. Additionally, low-income/CARE and MBL customers will be offered special payment arrangements resulting from fire-related outages, as necessary.
- Billing adjustments: Liberty will suspend billing until power is restored to impacted customers.
- Deposit waivers: Liberty will waive deposit requirements for customers who are seeking to re-establish service at either the same location or a new location.
- Extended payment plans: Special consideration will be granted for payment extension when customers experience tremendous loss (*i.e.* property loss).
- Suspension of disconnection and nonpayment fees: For customers impacted by wildfires, Liberty will suspend disconnection for non-payment and associated fees, waive the deposit and late fee requirements for affected customers who pay their utility bills late, and not report late payments by customers who are eligible for these protections to credit reporting agencies or to other such services.
- Repair processing and timing: Timing for repair procedures will be determined on the severity of the wildfire. As feasible, Liberty will accelerate the repair process.
- Access to utility representatives: If Liberty's offices are not impacted by the wildfire event, operations will resume and customer service representatives will be available to provide support. If offices are impacted, nearby offices and corporate communications will be available to customers.

3. Region prioritization

These customer protections are available to customers throughout Liberty's service territory. Liberty will provide descriptions of the customer protections offered to affected customers on a special landing page on its website and promote the page with social media campaigns. In addition, Liberty will contact impacted customers via multiple channels to bring awareness regarding these protections.

4. Progress on initiative

In 2021, Liberty continued to focus on outreach to its most vulnerable customers. This included outreach to MBL customers, including efforts to update contact records for wildfire event communications. CBO outreach was a focus in

2021, as Liberty understands that local organizations can utilize established communication channels to spread awareness and provide support to their respective communities.

5. Future improvements to initiative

Liberty will continue to evaluate new partnerships, programs and service offerings both directly provided by Liberty, as well as provided through community partnerships.

7.3.9.4. Disaster and emergency preparedness plan

In accordance with G.O. 166, Liberty has a CEMP that outlines the policies and procedures for disaster and emergency events. The CEMP has undergone an internal review for improvement, and the Emergency Manager is responsible for oversight or the plan. In addition to annual reviews, Liberty continually looks for opportunities to improve the plan and to collaborate with local agencies, communities, and other stakeholders to maintain protocols and satisfy requirements.

7.3.9.5. Preparedness and planning for service restoration

As outlined in Liberty's CEMP pursuant to G.O. 166, Liberty has developed a PSPS plan that supplements and enhances protocols for preparedness and service restoration in the event of a disaster or emergency. Liberty reviews the plan annually to bolster its preparedness plan to meet compliance standards for service restoration. Please refer to Section 7.3.6.4 for more initiative details.

7.3.9.6. Protocols in place to learn from wildfire events

Any major wildfire event caused by Liberty would be considered an emergency situation, and activation of the CEMP would be in place. Post-incident lessons learned meetings and documentation would be generated and circulated, with resulting emergency preparedness improvements shared in training sessions with key personnel in the company.

7.3.10. Stakeholder Cooperation and Community Engagement

Liberty understands communication is essential to help mitigate the risk of wildfires and adverse impacts of PSPS events for our customers and community partners. Liberty remains committed to partnering with utility customers, elected officials, community-based organizations ("CBOs"), first responders, and all other public safety and community partners, understanding each partner plays a unique role in achieving wildfire prevention and mitigation in our service territory. Liberty provides an essential service, and it takes its role very seriously. This is especially true during times of potential PSPS events, when communities depend on complete, accurate, and timely information to protect their health and safety.

Liberty will continue to strive to educate stakeholders about wildfire preparedness, including PSPS events. It is Liberty's goal to enable those it serves with the necessary resources to navigate the adverse impacts of an emergency, wildfire, or PSPS event. Through educational campaigns and strategic partnerships, Liberty has implemented a robust, external communication strategy, which reflects lessons learned and evolving best practices. Liberty also leverages its partnerships with CBOs and stakeholders to amplify and disseminate emergency preparedness information.

Liberty remains committed to fostering these relationships and collaborating on new ways to better serve its communities in 2022 and beyond. As outlined below, Liberty will continue to leverage its partner network and agency relationships and will continue to strive for transparent education and messaging.

7.3.10.1. Community engagement

1. Risk to be mitigated

Working together with public safety partners, CBOs and customers is an important part of Liberty's wildfire safety education program. Communities are encouraged to understand the critical safety work underway in their area and are more prepared for wildfire season, specifically Public Safety Power Shutoff (PSPS) events. The goals of Liberty's detailed outreach and engagement plan includes the following, among others:

- Identifying and engaging with key stakeholder groups;
- Creating alignment between Liberty, customers, public safety partners, elected officials and the general public;
- Identifying opportunities to collaborate with key local agencies in the design and planning of wildfire mitigation work to leverage efficiencies in project execution or the pursuit of projects that are closely aligned with community priorities;
- Preparing public safety partners, agencies, and customers for PSPS events, mitigating the risks associated with those events for our most vulnerable customers; and
- Identifying AFN customers, AFN support resources, and engaging with CBO networks.

In addition, Liberty designs, translates, distributes and evaluates communications, including AFN and non-English speaking customers, to help facilitate the following for its customers and communities:

- Awareness of Liberty's wildfire mitigation efforts
- Increased personal preparedness for PSPS and wildfire events;
- Balanced communication to customer populations; and
- Customer self-identification of AFN status.

2. Initiative selection

Liberty develops an outreach and engagement plan for the various stakeholders within our service territory. Key stakeholders include public safety partners, including federal, state, local and tribal agencies, critical facilities such as water agencies, communications providers and hospitals, and customers, including MBL and AFN customers. Throughout the year, Liberty engages with these stakeholders regarding the company's critical wildfire mitigation efforts. Liberty's main outreach and engagement objectives for 2022 include:

- Adapting to shifting needs and priorities in emergency preparedness and wildfire mitigation;
- Hosting regionalized discussions with public safety partners to enhance knowledge of regional driving factors for PSPS events and other potential emergency events in their areas;
- Strengthening partnerships between public safety partners and Liberty representatives, establishing point-of-contacts that can address their needs both during an emergency event and throughout the year;
- Customizing outreach approach and cadence based upon the community's wildfire risk, with a key focus on providing more heavily impacted communities with information and resources; and
- Approaching public safety partners and customers with transparency while providing timely and accurate information that supports emergency preparedness and localized wildfire mitigation efforts

To further explain Liberty's community engagement approach, this section has been organized into the following categories:

Strategy and actions taken to identify and contact key community stakeholders: Liberty aims to collaborate with stakeholders to inform them of wildfire safety work in their area and address unique, local issues in real-time. Liberty recognizes its public safety partners and community organizations evolve to meet changing emergency conditions as Liberty does. That is why Liberty works to keep contact lists updated throughout the year, identifying and maintaining relationships within federal, state, local, and tribal agencies on a quarterly basis. These relationships enable Liberty representatives to include public safety partners and other stakeholder groups in future outreach engagements and in-emergency notifications.

Liberty collaborates with stakeholder representatives throughout its service territory, from local to federal levels. Liberty also has representatives who coordinate regularly with critical facilities and large businesses and are responsible for identifying and maintaining these contacts. Liberty representatives work to build trust with their respective stakeholder groups and are empowered to share information and seek feedback on future wildfire mitigation work.

Beyond existing relationships, Liberty continues to establish partnerships with CBO and AFN entities that may assist Liberty in our outreach and engagement efforts to at-risk populations. These entities can assist with identifying customer groups that require additional, specialized outreach. Liberty also follows best practice guidelines and seeks input from the other California IOUs and through its advisory committees to identify additional stakeholders.

Increase public awareness and support of utility wildfire mitigation activity: Wildfires are now a year-round threat in California. Throughout the year, Liberty executes comprehensive wildfire safety and PSPS preparedness outreach, using lessons learned and feedback received from other IOUs, customers, and stakeholders. Further, Liberty conducts community outreach to educate public safety partners, customers, and the general public on aspects of our wildfire mitigation practices, such as vegetation management and system hardening, and the role they play in helping to reduce wildfire risks in their communities.

In light of the COVID-19 pandemic, Liberty will adhere to public health guidelines when executing its outreach plan, including making all communications available in a digital form. In 2021, Liberty collaborated with public safety partners, critical facilities, and other stakeholders on outreach, including designing in-person and virtual meetings and community town halls. Liberty will continue to follow prevailing public health guidance when planning 2022 engagements and will also consider the preferences of public safety partners, customers, communities, and internal staff.

- **Public safety partner and critical facilities outreach**: Liberty works closely with public safety partners and critical facilities to inform them of Liberty's wildfire safety work in their area. Liberty encourages public safety partners and critical facilities to provide feedback and play an active role in providing additional outreach support to increase awareness and support of utility wildfire mitigation activities.
    - Listening sessions: Liberty meets with public safety partners in its service territory to share regional plans for wildfire mitigation, system resiliency and address steps being taken to incorporate the feedback received during the previous wildfire season. The purpose of the listening sessions is to provide public safety partners with an opportunity to have detailed conversations regarding wildfire mitigation work planned in their community and PSPS improvements. Feedback from the sessions has helped to shape local planning for PSPS events, including critical facility locations, community resource center (CRC) locations, and local contacts for emergency response
    - PSPS Tabletop Exercises: Liberty invites public safety partners to PSPS tabletop exercises, testing Liberty's ability to effectively communicate with our partners during PSPS events. Tabletop exercises help clarify roles and responsibilities during a PSPS event and provide an opportunity to identify possible areas of improvement. These PSPS tabletop exercises and workshops are a continued best practice in 2022. In 2021, Liberty hosted two tabletop exercises.
    - Additional PSPS workshops: Liberty hosts additional PSPS workshops for public safety partners, as needed. Liberty prioritizes topics that are most valuable to the jurisdictions, including localized drivers of PSPS, wildfire mitigation activities in their communities, and other topics of interest. Liberty aims to co-host public-facing events with public safety partners to address questions and concerns from the community related to PSPS and wildfires and partner on additional external outreach and engagement opportunities.
    - Stakeholder meetings: In 2021, Liberty conducted meetings with multiple stakeholder groups. Liberty will continue these meetings throughout 2022. Throughout 2022, Liberty will continue to engage with public safety partners and critical facilities to support wildfire, PSPS and emergency preparedness planning, including topics such as business continuity, backup power options, safety, among others.

- **Customer and Community Outreach**: Liberty engages with customers and communities regarding wildfire safety and PSPS preparedness year-round to increase public awareness and support of Liberty wildfire mitigation activities. Liberty prioritizes engagement with those most likely to be impacted by PSPS, which includes customers within Tier 2 and Tier 3 High Fire Threat District (HFTD) areas. It also includes additional touch points for MBL customers, those with limited English proficiency and the AFN community. Liberty will leverage multiple channels, such as virtual town halls, e-mails, bill inserts, postcards, radio, digital advertisements, print media, informational videos, social media, website, and possibly face-to-face meetings. Liberty will continue direct-to-customer outreach campaigns that are focused on, but are not limited to, personal PSPS preparedness, gathering updated contact information and sharing PSPS and emergency safety tips.
    - Communication for AFN populations and limited English proficiency populations: Liberty translates "critical information," which includes resources focused on emergency preparedness, wildfire safety, and PSPS preparedness. Additionally, Liberty continues to establish partnerships with CBOs to provide additional outreach support. Please see Section 8.4 for details on Liberty's communications for AFN populations.
    - Virtual Town Halls and other Community Events: Liberty hosts virtual town halls dedicated to providing information about Liberty's local wildfire mitigation efforts, PSPS and how to prepare and remain resilient through the events. Liberty plans to host events prior to July 1, 2022.These events are designed for anyone who is interested in learning more about Liberty's wildfire mitigation efforts and allow community members to ask questions and share feedback. Liberty plans to continue to host and/or participate in community events focused on customers with disabilities, seniors, and low-income customers, including participation in meetings hosted by CBOs. In 2022, the format and timing of community events will depend on COVID-19 safety protocols. As it becomes safe for customers, communities, and employees to gather, Liberty plans to resume in-person events, based on state and local health guidance.
    - Direct-to-Customer Outreach: To help customers prepare for emergencies and potential PSPS events, Liberty plans to conduct a multi-channel outreach and awareness campaign throughout 2022 including e-mails, homeowner's association ("HOA") newsletters, postcards, and more. Topics include, but are not limited to, calls to update customer contact information, directions to enroll in the MBL program, and PSPS awareness, AFN self-identification, and preparedness messaging. Virtual and in-person meetings with CBOs were an area of focus in 2021, and with two new positions focused on expanding these networks, Liberty plans to continue this effort throughout 2022. The addition of a bilingual Outreach Coordinator position will expand Liberty's ability to access local communities and provide additional Spanish communication support in 2022.
    - Website: Liberty's website is a key resource for information about wildfire mitigation activities, PSPS readiness initiatives, and PSPS event information. Liberty's website allows customers to have access to information before, during, and after a wildfire and/or PSPS event as well as a variety of topics associated with wildfire including wildfire safety, emergency preparedness, and PSPS planning and preparedness. Liberty looks to continually improve accessibility of materials throughout 2022.
    - Informational Videos: Liberty uses informational videos to inform customers about wildfire mitigation and PSPS preparedness. Liberty looks to continually improve accessibility of materials throughout 2022.
    - Social Media: Liberty regularly provides customer preparedness resources through its social media channels, including Twitter and Facebook. Liberty continues to work with public safety partners and CBOs to assist with communications and share information before and during PSPS events. Liberty plans to leverage its social media platform throughout 2022.

- Purchased Media/Advertising Campaign: This includes PSPS and WFM information in print, digital, and radio.
- Monthly Email: Liberty sends customers that provided an email address an email monthly. Liberty will provide information about wildfire mitigation activities and PSPS readiness initiatives periodically. In addition to the monthly email, Liberty will provide PSPS event information when applicable. Liberty plans to leverage its email platform throughout 2022.

- **Strategy and Actions Taken to Design, Translate, Distribute, and Evaluate Effectiveness of Related Communications**: As noted above, Liberty engages with public safety partners and critical facilities in multiple formats that foster open and transparent communication and encourage key stakeholders to provide candid feedback. When feasible, feedback is implemented into operational and/or engagement plans. Below is a list of evaluation mechanisms that Liberty employs to assess effectiveness of public safety partner and critical facility outreach and identify improvements as needed:
    - After-engagement internal evaluations: After each type of engagement (*e.g.*, listening sessions and tabletop exercises), Liberty evaluates feedback from stakeholders and determines where improvements can be made before the next engagement opportunity.
    - Feedback from local Liberty representatives: Local Liberty representatives seek feedback on communication effectiveness from public safety partners, community stakeholders and customers throughout the year, both in formal engagements and during informal conversations. Liberty evaluates the feedback and determines where improvements can be made before the next engagement opportunity.
    - Evaluation of feedback: The section above (Strategies and Actions Taken to Identify and Contact Key Community Stakeholders) also notes the various ways Liberty engages with customers. To measure effectiveness, Liberty collects feedback from customers on outreach and identifies barriers and areas for improvement. The feedback is collected both prior to and after wildfire and/or PSPS events. Below is a list of evaluation mechanisms that Liberty employs to assess effectiveness of customer outreach and identify improvements as needed:
        - Opinion surveys: Before and after the start of wildfire season, Liberty conducts semi-annual surveys with customers (in both English and non-English languages) to capture awareness and recall, understanding of, and satisfaction with Liberty's customer communications and to measure statistically significant changes over time. In 2021, CBOs were engaged in this survey effort and interviewed to gain perspectives helpful in determining effectiveness of Liberty's outreach and education.
        - Customer Feedback: Liberty regularly reviews customer sentiments received directly by the Customer Care Department, email, and social media outlets.
        - Web Traffic: Liberty measures traffic to relevant pages on its website, such as wildfire alerts, updates to contact information, wildfire, and PSPS safety pages. Website traffic is currently measured by assessing number of unique visitors, visits, and page views.
        - Click-through-rates of advertisements: Click-through-rate of advertisements is an industry-accepted standard that measures the number of people visiting a webpage who access a hyperlink to an advertisement (*e.g.*, wildfire safety). Advertisement click-through-rates measure the immediate response to an advertisement but not necessarily the overall response. Customers may see the advertisement, absorb the messaging, and choose to act later.

- Liberty filed its independent survey results as part of its 2021 PSPS Post Season Report on March 31, 2022. Liberty will continue to apply best practices and leverage lessons learned from its 2021 customer outreach experiences.

- **Strategies and Actions Taken to Address Concerns and Serve Needs of AFN Populations and Non-English-Speaking Customers**: Liberty is committed to providing additional services to AFN and medically sensitive customers by partnering with organizations that assist and provide services to these populations. Liberty will continue to encourage awareness and enrollment of the MBL Program. Please see Section 8.4, which provides more details on Liberty's AFN population support strategy before and during PSPS events, including programs that serve these customers, preparedness outreach, and events that serve AFN populations. This is also detailed in Liberty's 2022 AFN Plan, filed at the CPUC on January 31, 2022, and included as Attachment G.
    - MBL outreach: Liberty will continue to conduct outreach to eligible customers to drive participation in the program, collect contact information in preparation for PSPS events, and share other relevant programs and service information to streamline communications, as appropriate. This support includes:
        - Providing support to CBOs for outreach to MBL and AFN customers;
        - Increasing engagement with the healthcare industry to encourage more program enrollments;
        - Providing master meter tenant education with both owners and tenants;
        - And adding self-identified AFN customers to our outreach efforts.
    - AFN communities: Liberty will engage stakeholders who represent, support and advocate for our income-qualified customers and AFN communities to provide relevant updates and encourage participation in support programs such as California Alternate Rates for Energy, Energy Savings Assistance and MBL. Liberty will continue to seek other ways and opportunities to engage disadvantaged and underserved communities' stakeholders and customers, including:
        - Increasing network of CBOs throughout Liberty service territory;
        - Improving accessibility of information available to AFN customers;
        - Encouraging customer self-identification of AFN status;
        - Proactively seeking out opportunities to increase program awareness;
        - Utilizing a targeted outreach approach including community events and identifying opportunities for CBO and tribal collaboration to access AFN communities;
        - Providing bilingual support through utilization of new bilingual Outreach Coordinator;
        - Communicating via website, social media, customer emails, bill inserts, toolkits, and community meetings

3. Region prioritization

Public education and communication efforts target Liberty's entire service territory with a particular focus on the areas that are most at risk of PSPS or wildfire (High Fire Threat District). Liberty also focuses on areas with an elevated percentage of at-risk customers (MBL and AFN customers). Accordingly, in 2022, certain regions may receive more frequent and more customized engagements according to their needs based upon their past experiences with PSPS and/or wildfires

4. Progress on initiative

Below are some of Liberty's key 2021 engagement and outreach highlights:

- Attended or participated in over 23 meetings or events with various community leaders and public safety partners to share information related to Liberty's wildfire mitigation efforts, PSPS preparedness and community outreach

- Held four regional PSPS workshops / virtual town halls provide a localized update on wildfire safety work happening in respective communities and answer customer questions;
- Placed over 36 posts on Liberty's social media channels;
- Held 18 virtual and/or in-person meetings with CBOs to expand and/or establish local relationships to understand community needs and identify collaboration opportunities in terms of program enrollment, program awareness, and PSPS preparedness.

In 2022, Liberty plans to continue awareness campaigns that it pursued in 2021, with a focus on improved customer, community, utility readiness, and resiliency in the face of growing wildfire threat. Other unforeseen factors may have an impact on Liberty's outreach approach for 2022.

5. Future improvements to initiative

As referenced in the responses above, Liberty will continue to ground stakeholder cooperation and community engagement initiatives in customer and stakeholder feedback received annually. As new information, best practices, and lessons learned are available, Liberty will refine its stakeholder outreach and community engagement approach. A focus on AFN support will be considered in Liberty's approach in 2022

7.3.10.2. Cooperation and best practice sharing with agencies outside CA

Liberty continues to cooperate and share best practices with agencies outside California. Because of Liberty's proximity to Nevada, there are several collaborative efforts between NV Energy and Liberty. For example, Liberty and NV Energy share weather data and fuel sampling resources in order to reduce costs of these respective programs to customers. Further, NV Energy and Liberty hold recurring meetings to share updates to system hardening programs and to discuss local staffing and resources and other wildfire mitigation-related activities. Liberty is a member of the Western Energy Institute's (WEI) Western Region Mutual Assistance Group (WRMAG), which is a collaboration of western utilities that provide mutual assistance for emergency relief. Liberty is also a member of the Edison Electric Institute (EEI) and participates in EEI's wildfire mitigation working group to explore new wildfire mitigation technologies and share best practices.

7.3.10.3. Cooperation with suppression agencies

Refer to Sections 7.3.9.2 and Section 7.3.10.1.

7.3.10.4. Forest service and fuel reduction cooperation and joint roadmap

Refer to Sections 7.3.5.1 and Section 7.3.5.5.

8. PUBLIC SAFETY POWER SHUTOFF (PSPS)

8.1 Directional Vision for Necessity of PSPS

***Instructions**: Describe any lessons learned from PSPS since the last WMP submission and describe expectations for how the utility's PSPS program will evolve over the coming 1, 3, and 10 years. Be specific by including a description of the utility's protocols and thresholds for PSPS implementation. Include a quantitative description of the projected evolution over time of the circuits and numbers of customers that the utility expects will be impacted by any necessary PSPS events. The description of protocols must be sufficiently detailed and clear to enable a skilled operator to follow the same protocols.*

When calculating anticipated PSPS, consider recent weather extremes, including peak weather conditions over the past 10 years as well as recent weather years, and how the utility's current PSPS protocols would have been applied to those years.

Liberty has not executed a PSPS event since the program was developed in 2019, but in recent years California has seen an increase in catastrophic wildfire activity. Liberty's PSPS program is meant to be used a last resort and the decision to implement a PSPS is not taken lightly, which is why Liberty has invested heavily in the program. Developing thresholds, PSPS protocols and procedures, weather monitoring tools, community outreach efforts, CRC's, and training personnel are all part of these investments. As the program has progressed from 2019 to now, Liberty has greatly improved the level of preparedness needed to execute a PSPS and minimize the impacts to customers and remains dedicated to continued improvement.

There have been two potential events in which Liberty has made notifications to customers and other partners of the possibility of a PSPS where the decision was made not to de-energize. These events, as well as training exercises and collaboration with stakeholders familiar with PSPS events, have led to lessons learned in the form of post-event reports, hot washes, and cooperator feedback.

Some key lessons learned are as follows:

- Improve Public Safety Partner portal to provide more information regarding specific PSPS events to stakeholders.
- Streamline Incident Management Team ("IMT") meetings to make more efficient use of time. Have sub-meetings that prepare for situational report- outs in IMT meetings.
- Improve critical facility mapping so that it is incorporated in GIS and customer information system ("CIS").
- PSPS Event communication to make all departments to make aware of the need for all available employees to assist in PSPS response.
- Consolidate PSPS Operations and Communications playbooks to make rolls and responsibilities clear for IMT.

Many of these lessons learned have been captured in Liberty's updated PSPS playbook, first developed in 2020, with an updated version in 2022 to incorporate additional lessons learned and process flow for executing a PSPS event.

In the next three years, Liberty plans to develop an updated methodology for PSPS decision-making. Currently, Liberty's PSPS decision-making factors are based on weather characteristics that are known to have a high probability of consequential ignitions. The existing model is limited since it does not account for the implementation of WMP initiatives that can reduce the probability of ignition. As Liberty implements more technology, system hardening, and situational awareness, there will be a need to incorporate those efforts into PSPS decision-making. Grid hardening efforts include replacing overhead lines with covered conductor to protect high fire risk areas during volatile weather events and building resiliency corridors, including installation of microgrids in targeted high fire risk areas. The combination of covered conductor installations, resiliency corridors, and microgrids will reduce impacts and frequency of PSPS events and service interruptions. In the next few years, as the implementation of those efforts reduce the risk of ignition, the PSPS model will need to reflect those improvements in Liberty's PSPS thresholds. Additionally, in 2022 Liberty will be working to create a PSPS risk model that helps to quantify the risk of de-energizing power lines on customers so that it can weigh though risks against the consequences of ignition under extreme wildfire conditions.

Liberty has developed best practices to establish safeguards for customers, and the public, during PSPS events. In addition, Liberty efforts to provide mobile generation, enhanced communication devices, charging stations, battery storage for medical baseline customers, and other necessary customer facilities for PSPS events are ongoing.

Instructions for Table *8.1- 1**:** Rank order, from highest (1 – greatest anticipated change in reliability or impact on ignition probability or estimated wildfire consequence over the next 10 years) to lowest (9 - minimal change or impact, next 10 years), the characteristics of PSPS events (e.g., numbers of customers affected, frequency, scope, and duration), regardless of if the change is an increase or a decrease. To the right of the ranked magnitude of impact, indicate whether the impact would be a significant increase in reliability, a moderate increase in reliability, limited or no impact, a moderate decrease in reliability, or a significant decrease in reliability. For each characteristic, include comments describing the expected change and expected impact, using quantitative estimates wherever possible.*

Table 8.1- 1: Anticipated characteristics of PSPS use over next 10 years

Rank order 1-9	PSPS characteristic	Significantly increase; increase; no change; decrease; significantly decrease	Comments
1	Number of customers affected by PSPS events (total)	Decrease	A key objective for Liberty is to limit the number of customers impacted by PSPS events through various WMP initiatives. In time, grid hardening efforts such as covered conductor, microgrids, and the addition of sectionalizing devices will help to reduce the number of customers affected by PSPS.
2	Number of customers affected by PSPS events (normalized by fire weather, *e.g.*, Red Flag Warning line mile days)	Decrease	A key objective for Liberty is to limit the number of customers impacted by PSPS events through various WMP initiatives. In time, grid hardening efforts such as covered conductor, microgrids, and the addition of sectionalizing devices will help to reduce the number of customers affected by PSPS.
3	Frequency of PSPS events in number of instances where utility operating protocol requires de-energization of a circuit or portion thereof to reduce ignition probability (total)	Decrease	Weather is the primary factor that drives PSPS frequency. In time, grid hardening efforts, such as covered wire and microgrids, will eventually lead to higher thresholds for de-energization, which would potentially reduce the frequency of PSPS events.
4	Frequency of PSPS events in number of instances where utility operating protocol requires de-energization of a circuit or portion thereof to reduce ignition probability (normalized by fire weather, *e.g.*, Red Flag Warning line mile days)	Decrease	Weather is the primary factor that drives PSPS frequency. In time, grid hardening efforts, such as covered wire and microgrids, will eventually lead to higher thresholds for de-energization, which would potentially reduce the frequency of PSPS events.

Rank order 1-9	PSPS characteristic	Significantly increase; increase; no change; decrease; significantly decrease	Comments
5	Scope of PSPS events in circuit-events, measured in number of events multiplied by number of circuits targeted for de-energization (total)	Decrease	The work that results in reducing impact to customers and the frequency of events will also reduce the scope of PSPS events.
6	Scope of PSPS events in circuit-events, measured in number of events multiplied by number of circuits targeted for de-energization (normalized by fire weather, *e.g.*, Red Flag Warning line mile days)	Decrease	The work that results in reducing impact to customers and the frequency of events will also reduce the scope of PSPS events.
7	Duration of PSPS events in customer hours (total)	Decrease	Weather events determine the length of time circuits need to be de-energized. If scope and number of customers are being reduced over time, then re-energization time should decrease, which is a factor in the duration of PSPS events. PSPS training could reduce the duration of PSPS events with increased preparedness.
8	Duration of PSPS events in customer hours (normalized by fire weather, *e.g.*, Red Flag Warning line mile days)	Decrease	Weather events determine the length of time circuits need to be de-energized. If scope and number of customers are being reduced over time, then re-energization time should decrease, which is a factor in the duration of PSPS events. PSPS training could reduce the duration of PSPS events with increased preparedness.
9	Other (Describe) – Rank as 9 and leave other columns blank if no other characteristics associated with PSPS		

8.2 Protocols on Public Safety Power Shut-off

***Instructions**: Describe protocols on Public Safety Power Shut-off (PSPS or de-energization), highlighting changes since the previous WMP submission:*

1. *Method used to evaluate the potential consequences of PSPS and wildfires. Specifically, the utility is required to discuss how the relative consequences of PSPS and wildfires are compared and evaluated. In addition, the utility must report the wildfire risk thresholds and decision-making process that determine the need for a PSPS.*

Currently, Liberty uses a combination of Energy Release Component ("ERC") percentile, wind gust, and Fosberg Fire Weather Index ("FFWI") to assess de-energization decisions. The current threshold for most PSPS zones is 40 mph wind gust and FFWI of 50, with slightly higher thresholds for windier circuits. See question 3 of this section below where Liberty describes the PSPS decision flow chart.

Recent PSPS risk analysis includes estimating the frequency, or likelihood of PSPS event given historic weather data gridded on Liberty's overhead lines. Gridded Real Time Mesoscale Analysis ("RTMA") data was analyzed to estimate the frequency with which Liberty's overhead network is exposed to wind gust and spell out values close to these thresholds. The result of this analysis is shown in Table 8.1- 2 and Table 8.1- 3 for July and November and the full year detailed months are in Attachment I. The Tables provide an estimate of the annualized number of line mile hours that exceed the wind gust and FFWI thresholds by month.

Table 8.1- 2: Annualized Line Mile Hours Exceeding Joint FFWI/Wind Gust Criteria by Month, July

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	52	11	2	0	0	0
	50	46	11	2	0	0	0
	55	30	10	2	0	0	0
	60	21	9	2	0	0	0
	65	13	7	2	0	0	0
	70	2	1	1	0	0	0

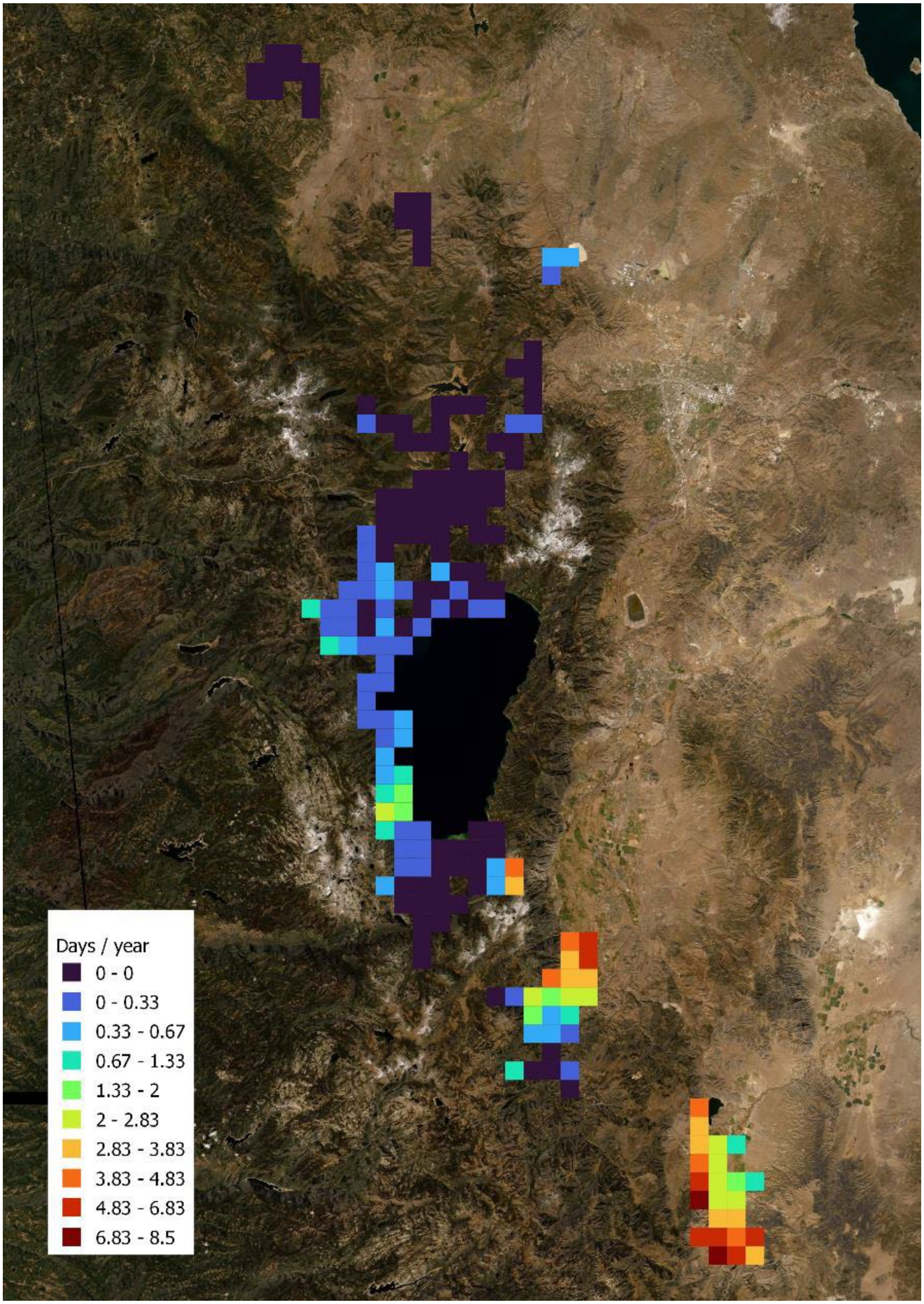
Table 8.1- 3: Annualized Line Mile Hours Exceeding Joint FFWI/Wind Gust Criteria by Month, November

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	1,631	1,119	742	463	265	182
	50	1,190	894	587	407	249	178
	55	907	735	515	365	241	176
	60	701	615	452	326	227	165
	65	527	485	384	291	204	155
	70	390	366	302	242	176	139

The monthly results demonstrate that wind gust and FFWI thresholds are conducive to PSPS likelihood is year-round and independent of fuel dryness. However, precipitation usually will preclude fire spread in Liberty's service territory from approximately December-April and these months are not factored into PSPS as a mitigation of fire risk. PSPS is most likely to occur in May to June, during low snow fall years, and from September to November for most years. The results also shows that peak PSPS frequency occurs during November, but only in years where season ending precipitation has not occurred. Although fuel moistures may trend toward seasonal lows in July and August, these tend to be the least windy months in Liberty's service territory because incoming troughs occur less frequently than later in the year, particularly October and November.

Although the analysis captures the seasonality of elevated fire weather conditions in Liberty's service territory, it provides no information regarding spatial patterns of elevated fire weather conditions. Another analysis performed on this dataset shows the PSPS risk map of the number of hourly records where wind gust exceeds 40 mph and FFWI simultaneously exceeds 50 in RTMA pixels containing overhead lines. See Figure X for the estimated number of days where wind gust and FFWI exceed thresholds (wind gust > 40 mph and FFWI > 50) by identifying days where 3 or more hourly records exceeded the same thresholds as the total annual hours in the same gridded plot. Since fuel dryness or presence of snow cover was not included in this analysis, Figure 8.1- 1 represents an upper limit on expected PSPS frequency, with actual PSPS frequency expected to be considerably lower.

Figure 8.1- 1: Number of days per year where 3 or more hourly records jointly exceed wind gust of 40 mph and FFWI 50



2. *Strategy to minimize public safety risk during high wildfire risk conditions and details of the considerations, including but not limited to a list and description of community assistance locations and services provided during a de-energization event.*

In coordination with the communities that it serves, Liberty has established a network of Community Resource Centers (“CRCs”) to assist communities in real time during extreme weather events. Planning factors for meeting the safety needs for access and functional needs and vulnerable populations have included local demographic data, as well as the company database of medical baseline customers. The establishment of CRCs was informed by presentations and discussions in seven Town Hall Meetings held in each of seven communities in Liberty’s service territory. Plan creation included consultation with regional local government, advisory boards, public safety partners, representatives of people/communities with access and functional needs, tribal representatives, senior citizen groups, business owners, community resource organizations, and public health and healthcare providers.

- Locations: If Liberty anticipates that the power will be off for an extended period, Liberty will open CRCs in the affected areas. The CRC locations selected by Liberty were identified through a rigorous process, which included input from fire and meteorological experts, as well as those areas most prone to extreme weather, as indicated by historical data. CRC locations identified to date include Walker CA, Markleeville CA, South Lake Tahoe CA, Truckee Tahoe Airport, Loyalton CA, and Portola CA .
- Accommodations: All CRCs are located in fixed facility locations known to the public. CRCs will have backup power or are located in areas that are contiguous to PSPS zones that would not be shut off in the event of a PSPS. They are ADA-compliant and meet the needs of people with access and functional needs, medical baseline, and other access and functional needs utility customers. FEMA June 2020 Mass Care Emergency Assistance Pandemic Planning Considerations were used to provide for adequate space for estimated occupancy and comply with social distancing and public health protocols.
- Services provided: Each CRC site meets fire codes and has at least two egress routes. Once activated, CRCs will operate in 14-hour shifts from 8:00 AM to 10:00 PM daily, until power to the affected community has been restored. The CRCs are capable of providing device charging stations, cellular network services, chairs, and restrooms. Volunteer organizations will provide bottled water and snacks to impacted area residents. Pre-identified Liberty subject matter experts (“SMEs”) will collaborate with volunteer staff at activated CRCs to communicate real-time PSPS updates directly to impacted community members.

Liberty’s additional strategies to improve public safety during high wildfire risk conditions include:

- Providing all field response employees with safety training aligned with their respective roles.
- Managing all electrical switching and reporting with appropriate controlling parties to enhance employee and public safety.
- Providing regular public information, typically in the form of media messages or alerts, regarding unsafe or hazardous areas or conditions.
- Utilizing the Emergency Alert System (“EAS”) through local or county Emergency Management or Public Safety offices in the event of an area emergency that is life or property threatening. Liberty will advise the emergency management agencies when such alert is necessary.
- Partnering with public safety agencies, as necessary, for traffic control and perimeter safety until qualified personnel arrive to clear the hazard situation.

3. Outline of tactical and strategic decision-making protocol for initiating a PSPS/de-energization (e.g., decision tree).

Liberty utilizes weather stations throughout its service territory and collaborates with Reax Engineering, a fire and weather scientific consultant, the National Weather Service ("NWS") in Reno, Nevada, and local fire officials, to monitor local weather conditions and evaluate when a PSPS should be initiated. The initiation of PSPS events are influenced by the following factors:

i. Red Flag Warnings: Issued by the NWS to alert of the onset, or possible onset, of critical weather or dry conditions that would lead to increases in utility-associated ignition probability and rapid rates of fire spread.
ii. Low humidity levels: Potential fuels are more likely to ignite when relative humidity is low and vapor pressure deficit is high.
iii. Forecast sustained winds and gusts: Fires burning under high winds can increase ember production rates and spotting distances. Winds also can transfer embers from lower fire risk areas into high risk areas, igniting spot fires and increasing wildfire potential.
iv. Dry fuel conditions: Trees and other vegetation act as fuel for wildfires. Fuels with low moisture levels easily ignite and can spread rapidly.
v. Observed Energy Release Component ("ERC")
vi. Observed wind gusts
vii. Observed Fosberg Fire Weather Index ("FFWI")
viii. Observed Burning Index ("BI")

In a case where the NWS forecasts three-second gusts greater than 50 mph, Liberty will check the location of those speeds, and areas where those speeds would peak, for the proximity to service equipment. If the gusts are near service equipment, the equipment is assessed to see if it is scheduled for repair. Liberty then monitors humidity and temperature levels to evaluate fuel conditions and forest susceptibility to fire for those areas. If an area is identified to be at risk of causing a wildfire, Liberty will first attempt to de-energize that line so that load at the end of the line can continue to be served. In the event that load has to be dropped, Liberty will attempt to minimize the lost load and customer disruption.

Liberty employs two de-energization decision trees, one for the Topaz and Muller 1296 r3 PSPS zones, and another for all other zones. In each case, the ERC, observed wind gust, and FFWI criteria are evaluated simultaneously to test whether any exceed the defined threshold:

Figure 8.1- 2 below represents the de-energization decision tree for Topaz and Muller 1296 r3 PSPS zones:

Figure 8.1- 2: De-energization Decision Tree for Topaz and Muller 1296 r3 PSPS Zones

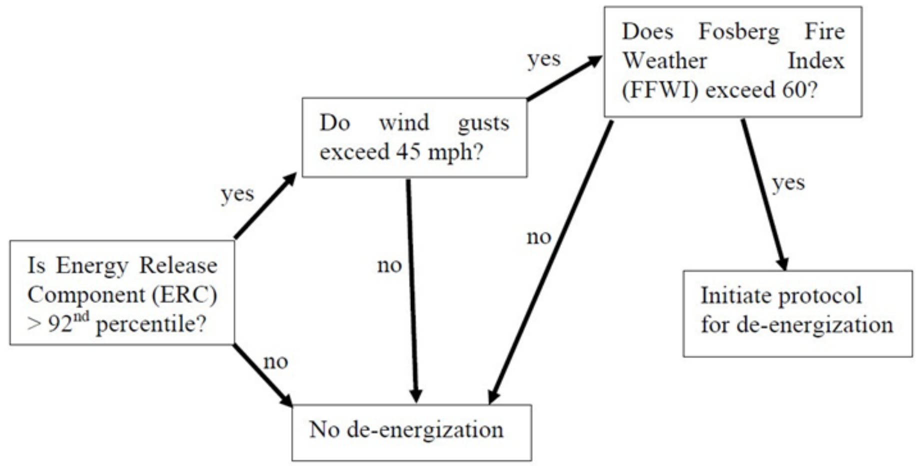
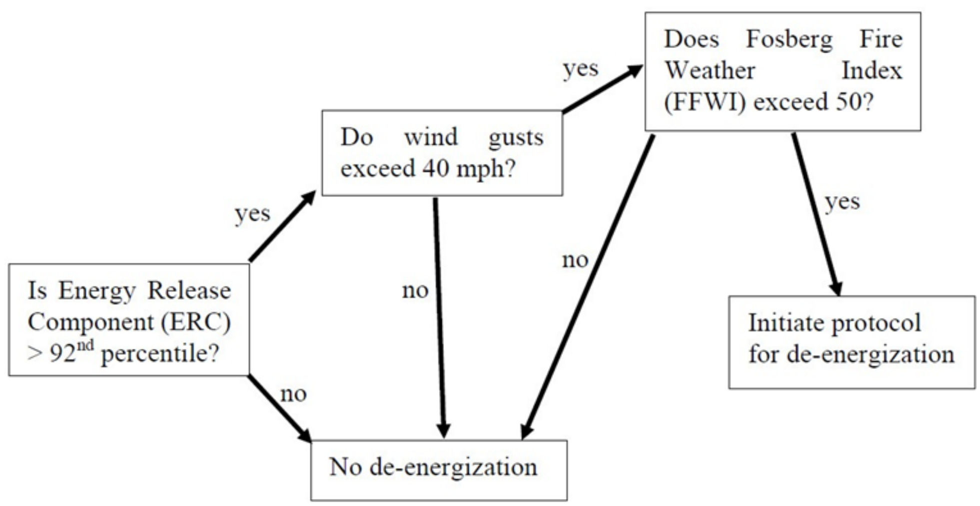


Figure 8.1- 3 below represents the de-energization decision tree for all other zones.

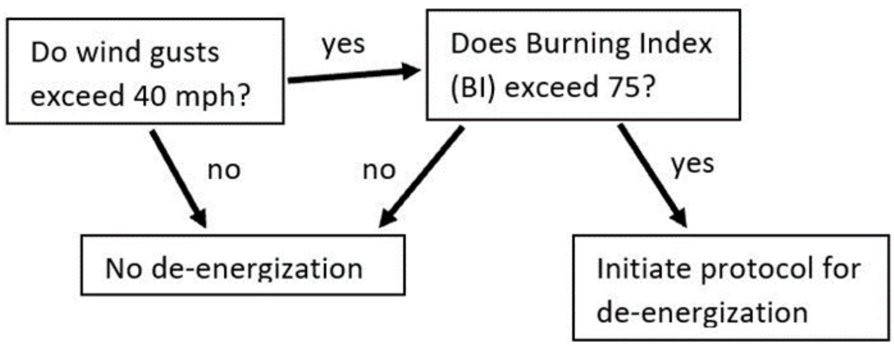
Figure 8.1- 3: De-energization Decision Tree for other PSPS zones



In January 2021, Liberty's Fire and Weather Scientific consultant, Reax Engineering, formulated an enhanced version of its fire weather forecasting tool to include an additional parameter known as Burning Index, or BI. BI adds an increased layer of information regarding fire potential to its existing predictive formula. It accounts for predominant fuel type, live and dead fuel moisture, and short-term fluctuations in fire weather conditions. Use of this new formula with increased information from newly installed additional weather stations will enable further granularity in the area of alternative responses to initiating a PSPS, such as managing recloser technology, de-energizing specific circuits and /or increasing patrols in specific geographic areas of concern. Liberty now utilizes both the current predictive formula and the enhanced model in order to assess de-energization decisions.

Figure 8.1- 4 below shows the current BI/gust de-energization formulation that is being evaluated by back testing against historical weather station observations and archived weather forecast data. The purpose of this formulation is to try to better capture "black swan" events, where extremely high winds may still have the ability to cause dangerous fire conditions even though temperatures are low and humidity levels are not critical, which can happen in the spring or fall more than the middle of the typical fire season.

Figure 8.1- 4: De-energization Decision Tree that Liberty is Utilizing in Addition to Figures 8-1 and 8-2



4. *Strategy to provide for safe and effective re-energization of any area that is de-energized due to PSPS protocol.*

Once Liberty has confirmed that conditions have subsided to the point that an energized grid does not pose a wildfire threat, the utility will begin the process of re-energizing power lines. Once a decision to re-energize has been made, Liberty will:

i. Patrol affected circuits prior to re-energization
ii. Inform all media and partners of the successful conclusion of the de-energization event and provide an update when power has been restored.
iii. Inform all customers impacted by the de-energization event that power has been restored via Everbridge (email, voice, and/or text).
iv. Post the time of power restoration(s) on the Liberty website and social media at the conclusion of the de-energization event.
v. Follow up with media and partners to facilitate effective communication and to determine if additional steps or efforts would be beneficial in the future.
vi. Provide a report to the Director of the Safety and Enforcement Division no later than 10 business days after the conclusion of the PSPS event that includes (i) an explanation of the decision to shut off power; (ii) all factors considered in the decision to shut off power, including wind speed, temperature, humidity, and moisture in the vicinity of the de-energized circuits; (iii) the time, place, and duration of the shut-off event; (iv) the number of affected customers, broken down by residential, medical baseline, commercial/industrial, and other; (v) any wind-related damage to overhead power-line facilities in the areas where power is shut off; (vi) a description of the notice to customers and any other mitigation provided; and (vii) any other matters the utility believes are relevant to the Commission's assessment of the reasonableness of Liberty's decision to shut off power.

5. *Company standards relative to customer communications, including consideration for the need to notify priority essential services – critical first responders, public safety partners, critical facilities and infrastructure, operators of telecommunications infrastructure, and water utilities/agencies. This section, or an appendix to this section, must include a complete listing of which entities the electrical corporation considers to be priority essential services. This section must also include a description of strategy and protocols to ensure timely notifications to customers, including access and functional needs populations, in the languages prevalent within the utility's service territory.*

Liberty will work to provide as much advanced notification as prudent to customers who may be affected by a PSPS event, and Liberty plans to provide even more advanced warning of a PSPS event to public safety partners, local utilities, and critical infrastructure, before a PSPS event is imminent. In order to avoid desensitization of the public, advanced notice to customers will be provided in a shorter timeframe and only when a PSPS event is likely. Under these considerations, Liberty has developed the following notification guidelines:

i. Up to eight days in advance: cities, counties, emergency services (public safety partners), regional utilities, cell tower operators, and critical facilities.
ii. Up to 72 hours in advance: medical baseline or medically sensitive patients, and cities, counties, emergency services (public safety partners), regional utilities, cell tower operators, and critical facilities.
iii. Up to 48 hours in advance: all affected or potentially affected customers, public safety partners, CPUC, and the media.
iv. Up to 24 hours in advance: all affected or potentially affected customers, public safety partners, CPUC and the media.
v. Immediately before de-energization: all affected or potentially affected customers, public safety partners, CPUC and the media.
vi. During the PSPS Event: all affected or potentially affected customers, public safety partners, CPUC, and the media.
vii. At the conclusion of the PSPS Event: all affected or potentially affected customers, public safety partners, CPUC, and the media.

A list of Priority Entities/Critical Facilities is below:

a. Health Care Hospitals
    a. Primary Care Hospitals
b. Utility Services/Districts
    a. Public Utility Districts
    b. Telecommunications
    c. Water/Water Treatment
    d. Pipeline
c. Public Safety Agencies
    a. Public Safety Dispatch Centers
    b. Law enforcement facilities/holding facilities
    c. Fire operations facilities
    d. Transportation equipment and facilities
d. Government facilities
e. Green Cross customers

Liberty will lead the communication effort and outreach for PSPS events. Liberty will be clear with its public safety partners when the information is intended to be public. When notifications are intended to be public, Liberty will provide clear messaging and request that each partner and media outlet assist in the distribution of the same information and messaging. To this point, Liberty has embarked on a system-wide outreach and awareness campaign to help customers and partners understand and prepare for a PSPS event.

6. *Protocols for mitigating the public safety impacts of these protocols, including impacts on first responders, health care facilities, operators of telecommunications infrastructure, and water utilities/agencies.*

Liberty provides ongoing public electric safety courses and information so the public will be prepared when an emergency event occurs. These programs are provided year-round to all levels of schools, business, service clubs, trade shows, and expositions. Additionally, Liberty routinely provides electric safety training to local and regional law enforcement, fire, county and state transportation, and other emergency response agencies.

During an emergency event, Liberty may utilize stand-by personnel, trained in general electrical safety, to observe and report hazardous conditions and assist in perimeter safety around identified hazards due to unsafe conditions until qualified electric personnel arrive. Personnel safety is identified as a key element in Liberty's Emergency Response Plan. Electric trade personnel, including groundpersons, helpers, apprentices, journeyman lineman, troublemen, and inspectors are provided the highest level of safety and skills training to perform in both daily and emergency situations. Only trained personnel may perform safety sensitive functions including switching, de-energizing, overhead and underground operations, repairing and assessing damage.

To improve employee and public safety, the design, installation and operation of equipment and automatic protection schemes for transmission and substation equipment must remain in place. Employees follow procedures in accordance with OSHA 1910.269 regulations. Non-trade personnel that are mobilized to assist with emergency repair (metering, meter reading, construction, etc.) are trained in general electric safety before assisting in emergency field response.

Liberty will respond to immediate life safety concerns as its top priority. Once a hazardous situation is reported, immediate response will be provided by line crews, trouble men, inspectors or other trained personnel to assess and mitigate risk. Additionally:

i. All field response employees shall undergo safety training aligned with their respective roles.
ii. All electrical switching and reporting shall be managed by the appropriate controlling parties to enhance employee and public safety.
iii. Liberty will provide regular public information, typically in the form of media messages or alerts, regarding unsafe or hazardous areas or conditions that the public should be informed about.
iv. In the event of an area emergency that is life or property threatening, the Emergency Alert System ("EAS") shall be enabled through the local or county Emergency Management or Public Safety office. Liberty will advise the emergency management agencies when such alert is essential.
v. Public safety agencies will be utilized, as necessary, for traffic control and perimeter safety until qualified personnel arrive to clear the hazard situation. Agencies will be used, if necessary, to control public disturbances and establish safety controls for the public.
vi. Employees will be monitored for appropriate meal breaks, hours worked, and safety compliance; when emergencies are expected to last more than 24 hours. Shifts will be established to cover work, and employees will be given appropriate rest periods.
vii. Weather and road conditions will be are monitored for worsening conditions so that workers are not stranded at remote work locations.
viii. Work may be curtailed until safe work conditions prevail.

8.3 Projected changes to PSPS impact

***Instructions**: Describe utility-wide plan to reduce scale, scope and frequency of PSPS for each of the following time periods, highlighting changes since the prior WMP report and including key program targets used to track progress over time,*

1. *By June 1 of current year*
2. *By September 1 of current year*
3. *By next WMP Update*

Liberty has focused extensive efforts on evaluating its current PSPS protocols and expanding on those protocols. Specifically, in January 2021, Liberty's Fire and Weather Scientific consultant, Reax Engineering, formulated an enhanced version of its fire weather forecasting tool to include an additional parameter known as Burning Index, or BI. BI adds an increased layer of information regarding fire potential to its predictive formula. The BI decision tree is currently being monitored in parallel with the original decision trees for the 2022 upcoming fire season.

Liberty is also finalizing updates to the PSPS playbook, which will consolidate both an operations and communications playbook into one comprehensive PSPS playbook. This is meant to provide a single source of documentation to be used during PSPS events and will lead to easier to follow processes and communications procedures. Updates will include some lessons learned from previous near misses and feedback collected from stakeholders. Liberty's upcoming PSPS training exercises will include participation from local public safety partners, critical facility operators, CBO's, as well as the CPUC, CalOES, and CAL FIRE.

By the next WMP update, Liberty will expand on the updated risk modeling work that uses zonal statistics generated for each circuit to summarize fire model outputs at the circuit level which would make existing PSPS zones more precise. The data in Table 4.5- 2 from Section 4.5.1.2 showing modeled fire size by circuit can be generated into polygons such as PSPS zone. More granular PSPS zones can lead to better circuit segment isolation potentially reduce PSPS impacts during certain weather conditions.

8.4 Engaging vulnerable communities

***Instructions**: Report on the following:*

1. *Describe protocols for PSPS that are intended to mitigate the public safety impacts of PSPS on vulnerable, marginalized and/or at-risk communities. Describe how the utility is identifying these communities.*

Protecting the health and safety of its vulnerable/AFN customers and communities is among Liberty's highest priorities during an emergency, wildfire, or PSPS event. Liberty's protocols for PSPS that are intended to mitigate the public safety impacts of PSPS on AFN customers are described in detail in Liberty's 2022 AFN Plan, include as Attachment G. Liberty conducts outreach related to emergency preparedness, provides advanced notification during PSPS events and offers additional services and resources to these customers in advance of and during PSPS events. Throughout 2021, Liberty worked to make potential PSPS events less burdensome for its customers. These accomplishments include, but are not limited to:

- Development of partnerships with CBOs to help support AFN customers with resources before, during and after PSPS events or wildfires;
- Updating the Liberty website to share more transparent PSPS preparedness, awareness, and status information;
- Internal system modifications to improve ability to track AFN categories beyond MBL;
- Development of self-identification tool available on the web in both English and Spanish

In 2022, Liberty will continue to establish partnerships with CBOs and continue to integrate these groups into PSPS operations. Liberty is working to expand opportunities for customers to self-identify as AFN without impinging on any HIPAA and/or CCPA data privacy laws. Identification of AFN customers is outlined in Liberty's 2022 AFN Plan, included as Attachment G, and includes utilizing existing program enrollment data, AFN self-identification tools developed in 2021, CBO partnerships, and collaborative outreach.

PSPS notifications: Liberty will notify AFN customers before, during, and after a PSPS through the following channels:

- Everbridge alerts: Liberty will distribute an alert through the Everbridge system notifying customers of the status of the PSPS. The Everbridge system consists of a three-part alert: first a text is sent, then an email, and lastly a call.
- CBOs: Liberty will notify CBOs that serve AFN populations of the status of the PSPS and request that they distribute the alert to their contact list. These CBOs may include homeless shelters, food banks, special needs programs.
- Critical facilities and infrastructure: Liberty will notify critical facilities and infrastructure of the status of the PSPS and request that they distribute the alert to their own AFN contact lists. These critical facilities and infrastructure include police stations, fire stations, emergency operations centers, schools, jails and prisons, public health departments, medical facilities, including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers, and hospice facilities, and facilities associated with automobile, rail, and aviation transportation for civilian and military purposes.
- Website: Liberty will publish an alert to the website notifying customers of the status of the PSPS. Microsites are made available in both English and Spanish during a PSPS event.
- Social Media: Liberty will post content to Facebook and Twitter notifying customers of the status of the PSPS.
- Customer Email: Liberty will distribute an email to AFN customers notifying them of the status of the PSPS. An enhancement in 2021 includes Spanish language messaging within PSPS customer emails.
- News Release and Public Service Announcements: Liberty will distribute a news release and/or a public service announcement to local media outlets alerting customers of the status of the PSPS. In 2021, Liberty added multicultural media outlets to lists of media contacts utilized for PSPS notification.
- Customer Service Representatives (CSR): Liberty will arm CSRs with information and resources for AFN customers during a PSPS.
- MBL customer notification: To identify MBL customers for an event, Liberty identifies MBL customers with accounts in the potentially impacted PSPS zone. To contact MBL customers behind master-metered accounts, Liberty consults a list of master-metered locations to determine if these meters are in the PSPS de-energization zone. Each master meter has a database that provides behind-the-meter information. From this database, Liberty can identify MBL customers and what units they occupy. The communication steps utilized for MBL customer contact also apply to master-metered MBL customer contact. The MBL notification sequence is as follows:
    - i. Everbridge notification (providing text, email, and voice push notifications, with receipt verification capability);
    - ii. If no positive contact, phone call to customer from customer service representative;
    - iii. If no positive contact, physical site visit to the residence;
    - iv. If no positive contact, door hanger notification left at the residence

2. *List all languages which are "prevalent" in utility's territory. A language is prevalent if it is spoken by 1,000 or more persons in the utility's territory or if it is spoken by 5% or more of the population within a "public safety answering point" in the utility territory19 (D.20-03-004).*

Liberty is committed to providing resources to customers in their primary language. The following languages have been identified as "prevalent" in its service territory: English and Spanish.

3. *List all languages for which public outreach material is available, in written or oral form.*

To complement the public education channels across the service territory, Liberty has developed access to in-language PSPS and wildfire safety preparedness and event information designed to reach disadvantaged communities and non-English proficient audiences in the territory. Liberty provides wildfire safety and PSPS-related communications in the following required languages: English, Spanish, German, French and Chinese.

4. *Detail the community outreach efforts for PSPS and wildfire-related outreach. Include efforts to reach all languages prevalent in utility territory.*

Refer to Section 7.3.10, which describes Liberty's PSPS and wildfire-related outreach in detail.

8.5 PSPS-specific metrics

Instructions: *PSPS data reported quarterly. Placeholder tables below to be filled in based on quarterly data.*

Instructions for PSPS table Attachment 3: *In the attached spreadsheet document, report performance on the following PSPS metrics within the utility's service territory over the past seven years as needed to correct previously reported data. Where the utility does not collect its own data on a given metric, the utility is required to work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in the "Comments" column.*

Table 11: Recent Use of PSPS and Other PSPS Metrics is provided in Attachment A.

8.6 Identification of frequency de-energized circuits

Instructions: *Senate Bill 533 (2021) added an additional requirement to the WMPs. Pub. Util. Code Section 8386(c)(8) requires the "Identification of circuits that have frequently been de-energized[24] pursuant to a de-energization event to mitigate the risk of wildfire and the measures taken, or planned to be taken, by the electrical corporation to reduce the need for, and impact of, future de-energization of those circuits, including, but not limited to, the estimated annual decline in circuit de-energization and de-energization impact on customers, and replacing, hardening, or undergrounding any portion of the circuit or of upstream transmission or distribution lines." To comply with this statutory addition, utilities are required to populate Table 8.6-1 and provide a map showing the listed frequently de-energized circuits*.

Liberty has not executed a PSPS event since the program was developed in 2019.

[24] "Frequently de-energized circuit" has been defined in the glossary as "A circuit which has been de-energized pursuant to a de-energization event to mitigate the risk of wildfire three or more times in a calendar year."

9. APPENDIX

9.1 Definitions of initiative activities by category

Category	Initiative activity	Definition
A. Risk mapping and simulation	A summarized risk map that shows the overall ignition probability and estimated wildfire consequence along the electric lines and equipment	Development and use of tools and processes to develop and update risk map and simulations and to estimate risk reduction potential of initiatives for a given portion of the grid (or more granularly, *e.g.*, circuit, span, or asset). May include verification efforts, independent assessment by experts, and updates.
	Climate-driven risk map and modeling based on various relevant weather scenarios	Development and use of tools and processes to estimate incremental risk of foreseeable climate scenarios, such as drought, across a given portion of the grid (or more granularly, *e.g.*, circuit, span, or asset). May include verification efforts, independent assessment by experts, and updates.
	Ignition probability mapping showing the probability of ignition along the electric lines and equipment	Development and use of tools and processes to assess the risk of ignition across regions of the grid (or more granularly, *e.g.*, circuits, spans, or assets).
	Initiative mapping and estimation of wildfire and PSPS risk-reduction impact	Development of a tool to estimate the risk reduction efficacy (for both wildfire and PSPS risk) and risk-spend efficiency of various initiatives.
	Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment	Development and use of tools and processes to assess the impact of potential ignition and risk to communities (*e.g.*, in terms of potential fatalities, structures burned, monetary damages, area burned, impact on air quality and greenhouse gas, or GHG, reduction goals, etc.).
B. Situational awareness and forecasting	Advanced weather monitoring and weather stations	Purchase, installation, maintenance, and operation of weather stations. Collection, recording, and analysis of weather data from weather stations and from external sources.
	Continuous monitoring sensors	Installation, maintenance, and monitoring of sensors and sensorized equipment used to monitor the condition of electric lines and equipment.
	Fault indicators for detecting faults on electric lines and equipment	Installation and maintenance of fault indicators.
	Forecast of a fire risk index, fire potential index, or similar	Index that uses a combination of weather parameters (such as wind speed, humidity, and temperature), vegetation and/or fuel conditions, and other factors to judge current fire risk and to create a forecast indicative of fire risk. A sufficiently granular index shall inform operational decision-making.
	Personnel monitoring areas of electric lines and equipment in elevated fire risk conditions	Personnel position within utility service territory to monitor system conditions and weather on site. Field observations shall inform operational decisions.

Category	Initiative activity	Definition
	Weather forecasting and estimating impacts on electric lines and equipment	Development methodology for forecast of weather conditions relevant to utility operations, forecasting weather conditions and conducting analysis to incorporate into utility decision-making, learning and updates to reduce false positives and false negatives of forecast PSPS conditions.
C. Grid design and system hardening	Capacitor maintenance and replacement program	Remediation, adjustments, or installations of new equipment to improve or replace existing capacitor equipment.
	Circuit breaker maintenance and installation to de-energize lines upon detecting a fault	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.
	Covered conductor installation	Installation of covered or insulated conductors to replace standard bare or unprotected conductors (defined in accordance with G.O. 95 as supply conductors, including but not limited to lead wires, not enclosed in a grounded metal pole or not covered by: a “suitable protective covering” (in accordance with Rule 22.8), grounded metal conduit, or grounded metal sheath or shield). In accordance with G.O. 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non-conductive material having the electrical insulating efficiency (12kV/in. dry) and impact strength (20ft.-lbs) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.
	Covered conductor maintenance	Remediation and adjustments to installed covered or insulated conductors. In accordance with G.O. 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non-conductive material having the electrical insulating efficiency (12kV/in. dry) and impact strength (20ft.-lbs.) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.

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Category	Initiative activity	Definition
	Crossarm maintenance, repair, and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing crossarms, defined as horizontal support attached to poles or structures generally at right angles to the conductor supported in accordance with G.O. 95.
	Distribution pole replacement and reinforcement, including with composite poles	Remediation, adjustments, or installations of new equipment to improve or replace existing distribution poles (*i.e.*, those supporting lines under 65kV), including with equipment such as composite poles manufactured with materials reduce ignition probability by increasing pole lifespan and resilience against failure from object contact and other events.
	Expulsion fuse replacement	Installations of new and CAL FIRE-approved power fuses to replace existing expulsion fuse equipment.
	Grid topology improvements to mitigate or reduce PSPS events	Plan to support and 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, microgrids, or local generation.
	Installation of system automation equipment	Installation of electric equipment that increases the ability of the utility to automate system operation and monitoring, including equipment that can be adjusted remotely such as automatic reclosers (switching devices designed to detect and interrupt momentary faults that can reclose automatically and detect if a fault remains, remaining open if so).
	Maintenance, repair, and replacement of connectors, including hotline clamps	Remediation, adjustments, or installations of new equipment to improve or replace existing connector equipment, such as hotline clamps.
	Mitigation of impact on customers and other residents affected during PSPS event	Actions taken to improve access to electricity for customers and other residents during PSPS events, such as installation and operation of local generation equipment (at the community, household, or other level).
	Other corrective action	Other maintenance, repair, or replacement of utility equipment and structures so that they function properly and safely, including remediation activities (such as insulator washing) of other electric equipment deficiencies that may increase ignition probability due to potential equipment failure or other drivers.
	Pole loading infrastructure hardening and replacement program based on pole loading assessment program	Actions taken to remediate, adjust, or install replacement equipment for poles that the utility has identified as failing to meet safety factor requirements in accordance with G.O. 95 or additional utility standards in the utility's pole loading assessment program.
	Transformers maintenance and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing transformer equipment.

Category	Initiative activity	Definition
	Transmission tower maintenance and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing transmission towers (*e.g.*, structures such as lattice steel towers or tubular steel poles that support lines at or above 65kV).
	Undergrounding of electric lines and/or equipment	Actions taken to convert overhead electric lines and/or equipment to underground electric lines and/or equipment (*i.e.*, located underground and in accordance with G.O. 128).
	Updates to grid topology to minimize risk of ignition in HFTDs	Changes in the plan, installation, construction, removal, and/or undergrounding to minimize the risk of ignition due to the design, location, or configuration of utility electric equipment in HFTDs.
D. Asset management and inspections	Detailed inspections of distribution electric lines and equipment	In accordance with G.O. 165, careful visual inspections of overhead electric distribution lines and equipment where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.
	Detailed inspections of transmission electric lines and equipment	Careful visual inspections of overhead electric transmission lines and equipment where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.
	Improvement of inspections	Identifying and addressing deficiencies in inspections protocols and implementation by improving training and the evaluation of inspectors.
	Infrared inspections of distribution electric lines and equipment	Inspections of overhead electric distribution lines, equipment, and right-of-way using infrared (heat-sensing) technology and cameras that can identify "hot spots", or conditions that indicate deterioration or potential equipment failures, of electrical equipment.
	Infrared inspections of transmission electric lines and equipment	Inspections of overhead electric transmission lines, equipment, and right-of-way using infrared (heat-sensing) technology and cameras that can identify "hot spots", or conditions that indicate deterioration or potential equipment failures, of electrical equipment.
	Intrusive pole inspections	In accordance with G.O. 165, intrusive inspections involve movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading.
	LiDAR inspections of distribution electric lines and equipment	Inspections of overhead electric transmission lines, equipment, and right-of-way using LiDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).

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Category	Initiative activity	Definition
	LiDAR inspections of transmission electric lines and equipment	Inspections of overhead electric distribution lines, equipment, and right-of-way using LiDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).
	Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations	Inspections of overhead electric transmission lines, equipment, and right-of-way that exceed or otherwise go beyond those mandated by rules and regulations, including G.O. 165, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.
	Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations	Inspections of overhead electric distribution lines, equipment, and right-of-way that exceed or otherwise go beyond those mandated by rules and regulations, including G.O. 165, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.
	Patrol inspections of distribution electric lines and equipment	In accordance with G.O. 165, simple visual inspections of overhead electric distribution lines and equipment that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.
	Patrol inspections of transmission electric lines and equipment	Simple visual inspections of overhead electric transmission lines and equipment that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.
	Pole loading assessment program to determine safety factor	Calculations to determine whether a pole meets pole loading safety factor requirements of G.O. 95, including planning and information collection needed to support said calculations. Calculations shall consider many factors including the size, location, and type of pole; types of attachments; length of conductors attached; and number and design of supporting guys, per D.15-11-021.
	Quality assurance / quality control of inspections	Establishment and function of audit process to manage and confirm work completed by employees or subcontractors, including packaging QA/QC information for input to decision-making and related integrated workforce management processes.
	Substation inspections	In accordance with G.O. 175, inspection of substations performed by qualified persons and according to the frequency established by the utility, including record-keeping.

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Category	Initiative activity	Definition
E. Vegetation management and inspection	Additional efforts to manage community and environmental impacts	Plan and execution of strategy to mitigate negative impacts from utility vegetation management to local communities and the environment, such as coordination with communities to plan and execute vegetation management work or promotion of fire-resistant planting practices
	Detailed inspections of vegetation around distribution electric lines and equipment	Careful visual inspections of vegetation around the right-of-way, where individual trees are carefully examined, visually, and the condition of each rated and recorded.
	Detailed inspections of vegetation around transmission electric lines and equipment	Careful visual inspections of vegetation around the right-of-way, where individual trees are carefully examined, visually, and the condition of each rated and recorded.
	Emergency response vegetation management due to red flag warning or other urgent conditions	Plan and execution of vegetation management activities, such as trimming or removal, executed based upon and in advance of forecast weather conditions that indicate high fire threat in terms of ignition probability and wildfire consequence.
	Fuel management and reduction of “slash” from vegetation management activities	Plan and execution of fuel management activities that reduce the availability of fuel in proximity to potential sources of ignition, including both reduction or adjustment of live fuel (in terms of species or otherwise) and of dead fuel, including "slash" from vegetation management activities that produce vegetation material such as branch trimmings and felled trees.
	Improvement of inspections	Identifying and addressing deficiencies in inspections protocols and implementation by improving training and the evaluation of inspectors.
	LiDAR inspections of vegetation around distribution electric lines and equipment	Inspections of right-of-way using LiDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).
	LiDAR inspections of vegetation around transmission electric lines and equipment	Inspections of right-of-way using LiDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).
	Other discretionary inspections of vegetation around distribution electric lines and equipment	Inspections 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.
	Other discretionary inspections of vegetation around transmission electric lines and equipment	Inspections 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.

Category	Initiative activity	Definition
	Patrol inspections of vegetation around distribution electric lines and equipment	Visual inspections of vegetation along rights-of-way that is designed to identify obvious hazards. Patrol inspections may be carried out in the course of other company business.
	Patrol inspections of vegetation around transmission electric lines and equipment	Visual inspections of vegetation along rights-of-way that is designed to identify obvious hazards. Patrol inspections may be carried out in the course of other company business.
	Quality assurance / quality control of vegetation inspections	Establishment and function of audit process to manage and confirm work completed by employees or subcontractors, including packaging QA/QC information for input to decision-making and related integrated workforce management processes.
	Recruiting and training of vegetation management personnel	Programs to ensure that the utility is able to identify and hire qualified vegetation management personnel and to ensure that both full-time employees and contractors tasked with vegetation management responsibilities are adequately trained to perform vegetation management work, according to the utility's wildfire mitigation plan, in addition to rules and regulations for safety.
	Remediation of at-risk species	Actions taken to reduce the ignition probability and wildfire consequence attributable to at-risk vegetation species, such as trimming, removal, and replacement.
	Removal and remediation of trees with strike potential to electric lines and equipment	Actions taken to remove or otherwise remediate trees that could potentially strike electrical equipment, if adverse events such as failure at the ground-level of the tree or branch breakout within the canopy of the tree, occur.
	Substation inspection	Inspection of vegetation surrounding substations, performed by qualified persons and according to the frequency established by the utility, including record-keeping.
	Substation vegetation management	Based on location and risk to substation equipment only, actions taken to reduce the ignition probability and wildfire consequence attributable to contact from vegetation to substation equipment.
	Vegetation inventory system	Inputs, operation, and support for centralized inventory of vegetation clearances updated based upon inspection results, including (1) inventory of species, (2) forecasting of growth, (3) forecasting of when growth threatens minimum right-of-way clearances (“grow-in” risk) or creates fall-in/fly-in risk.
	Vegetation management to achieve clearances around electric lines and equipment	Actions taken to ensure that vegetation does not encroach upon the minimum clearances set forth in Table 1 of G.O. 95, measured between line conductors and vegetation, such as trimming adjacent or overhanging tree limbs.
F. Grid operations and protocols	Automatic recloser operations	Designing and executing protocols to deactivate automatic reclosers based on local conditions for ignition probability and wildfire consequence.

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Category	Initiative activity	Definition
	Crew-accompanying ignition prevention and suppression resources and services	Those firefighting staff and equipment (such as fire suppression engines and trailers, firefighting hose, valves, and water) that are deployed with construction crews and other electric workers to provide site-specific fire prevention and ignition mitigation during on-site work
	Personnel work procedures and training in conditions of elevated fire risk	Work activity guidelines that designate what type of work can be performed during operating conditions of different levels of wildfire risk. Training for personnel on these guidelines and the procedures they prescribe, from normal operating procedures to increased mitigation measures to constraints on work performed.
	Protocols for PSPS re-energization	Designing and executing procedures that accelerate the restoration of electric service in areas that were de-energized, while maintaining safety and reliability standards.
	PSPS events and mitigation of PSPS impacts	Designing, executing, and improving upon protocols to conduct PSPS events, including development of advanced methodologies to determine when to use PSPS, and to mitigate the impact of PSPS events on affected customers and local residents.
	Stationed and on-call ignition prevention and suppression resources and services	Firefighting staff and equipment (such as fire suppression engines and trailers, firefighting hose, valves, firefighting foam, chemical extinguishing agent, and water) stationed at utility facilities and/or standing by to respond to calls for fire suppression assistance.
G. Data governance	Centralized repository for data	Designing, maintaining, hosting, and upgrading a platform that supports storage, processing, and utilization of all utility proprietary data and data compiled by the utility from other sources.
	Collaborative research on utility ignition and/or wildfire	Developing and executing research work on utility ignition and/or wildfire topics in collaboration with other non-utility partners, such as academic institutions and research groups, to include data-sharing and funding as applicable.
	Documentation and disclosure of wildfire-related data and algorithms	Design and execution of processes to document and disclose wildfire-related data and algorithms to accord with rules and regulations, including use of scenarios for forecasting and stress testing.
	Tracking and analysis of near miss data	Tools and procedures to monitor, record, and conduct analysis of data on near miss events.
H. Resource allocation methodology	Allocation methodology development and application	Development of prioritization methodology for human and financial resources, including application of said methodology to utility decision-making.
	Risk reduction scenario development and analysis	Development of modeling capabilities for different risk reduction scenarios based on wildfire mitigation initiative implementation; analysis and application to utility decision-making.

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Category	Initiative activity	Definition
	Risk spend efficiency analysis	Tools, procedures, and expertise to support analysis of wildfire mitigation initiative risk-spend efficiency, in terms of MAVF and/ or MARS methodologies.
I. Emergency planning and preparedness	Adequate and trained workforce for service restoration	Actions taken to identify, hire, retain, and train qualified workforce to conduct service restoration in response to emergencies, including short-term contracting strategy and implementation.
	Community outreach, public awareness, and communications efforts	Actions to identify and contact key community stakeholders; increase public awareness of emergency planning and preparedness information; and design, translate, distribute, and evaluate effectiveness of communications taken before, during, and after a wildfire, including Access and Functional Needs populations and Limited English Proficiency populations in particular.
	Customer support in emergencies	Resources dedicated to customer support during emergencies, such as website pages and other digital resources, dedicated phone lines, etc.
	Disaster and emergency preparedness plan	Development of plan to deploy resources according to prioritization methodology for disaster and emergency preparedness of utility and within utility service territory (such as considerations for critical facilities and infrastructure), including strategy for collaboration with Public Safety Partners and communities.
	Preparedness and planning for service restoration	Development of plans to prepare the utility to restore service after emergencies, such as developing employee and staff trainings, and to conduct inspections and remediation necessary to re-energize lines and restore service to customers.
	Protocols in place to learn from wildfire events	Tools and procedures to monitor effectiveness of strategy and actions taken to prepare for emergencies and of strategy and actions taken during and after emergencies, including based on an accounting of the outcomes of wildfire events.
J. Stakeholder cooperation and community engagement	Community engagement	Strategy and actions taken to identify and contact key community stakeholders; increase public awareness and support of utility wildfire mitigation activity; and design, translate, distribute, and evaluate effectiveness of related communications. Includes specific strategies and actions taken to address concerns and serve needs of Access and Functional Needs populations and Limited English Proficiency populations in particular.
	Cooperation and best practice sharing with agencies outside CA	Strategy and actions taken 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.

Category	Initiative activity	Definition
	Cooperation with suppression agencies	Coordination with CAL FIRE, federal fire authorities, county fire authorities, and local fire authorities to support planning and operations, including support of aerial and ground firefighting in real-time, including information-sharing, dispatch of resources, and dedicated staff.
	Forest service and fuel reduction cooperation and joint roadmap	Strategy and actions taken to engage with local, state, and federal entities responsible for or participating in forest management and fuel reduction activities; and design utility cooperation strategy and joint stakeholder roadmap (plan for coordinating stakeholder efforts for forest management and fuel reduction activities).

9.2 Citations for relevant statutes, Commission directives, proceedings and orders

Instructions: *Throughout the WMP, cite relevant state and federal statutes, Commission directives, orders, and proceedings. Place the title or tracking number of the statute in parentheses next to comment, or in the appropriate column if noted in a table. Provide in this section a brief description or summary of the relevant portion of the statute. Track citations as end- notes and order (1, 2, 3…) across sections (e.g., if section 1 has 4 citations, section 2 begins numbering at 5).*

Table 9-1: Citations

WMP Section	State and Federal Statutes, Commission Directives, Orders and Proceedings	Description
All	Resolution WSD-011	Resolution implementing the requirements of Public Utilities Code Sections 8389(d)(1), (2) and (4), related to catastrophic wildfire caused by electrical corporations subject to the Commission's regulatory authority
All	Public Utilities Code § 8386	Law that requires electric corporations to submit wildfire mitigation plans
All	R.18-10-007	Order Instituting Rulemaking (OIR) to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)
Section 4.6	Resolution WSD-002	Guidance Resolution on 2020 Wildfire Mitigation Plans Pursuant to Public Utilities Code Section 8386
Section 4.6	Resolution WSD-007	Resolution Ratifying Action of the Wildfire Safety Division on Liberty Utilities' (CalPeco Electric) LLC's 2020 Wildfire Mitigation Plan Pursuant to Public Utilities Code Section 8386.
Section 4.2	R.20-07-013	OIR to Further Develop a Risk-based Decision-making Framework for Electric and Gas Utilities
Section 7.3.4	Public Resources Code § 4292	CAL FIRE requires 10 feet of minimum clearance around the base of the pole cleared of all flammable vegetation down to bare soil and the removal of all dead tree branches within this cylinder up to the cross-arm (within the State Responsibility Area)
Section 7.3.9	D.20-03-004	Decision on community awareness and public outreach before, during and after a wildfire, and explaining next steps for other Phase 2 issues.

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WMP Section	State and Federal Statutes, Commission Directives, Orders and Proceedings	Description
Section 8.4.2		Decision in Rulemaking 18-10-007 requiring IOUs to conduct community awareness and public outreach before, during, and after a wildfire in any language that is "prevalent" in its service territory or portions thereof.
Section 8.2	D.19-05-042	CPUC Decision Adopting De-Energization (Public Safety Power Shutoff) Guidelines (Phase 1 Guidelines)
Section 8.2	D.20-05-051	CPUC Decision Adopting Phase 2 Updated and Additional Guidelines for De-Energization of Electric Facilities to Mitigate Wildfire Risk
Section 7.1 Section 7.3 Section 7.4	General Order 95	Overhead electric line design, construction, and maintenance requirements in order to ensure adequacy of service and safety; covers topics such as proper grounding, clearances, strength requirements, and tree trimming
Section 7.1 Section 7.3 Section 7.4	General Order 165	Inspection requirements for transmission and distribution facilities in order to ensure safety and high-quality electrical service; sets maximum allowable inspection cycle lengths, scheduling and performance of corrective action, record-keeping, and reporting
Section 7.1 Section 7.3	General Order 174	Inspection requirements for substations to promote the safety of workers, the public, and enable adequacy of service
Section 4.1 Section 7.1	Wildfire Safety Division Draft GIS Data Reporting Requirements and Schema for California Electrical Corporations	Sets forth requirements for WMP spatial data submissions
Section 4.6	Wildfire Safety Division Evaluation of Liberty's First Quarterly Report	Assesses Liberty's 2020 WMP Class B Deficiencies

Attachment A

2021 WMP Performance Metrics Data

Utility	Liberty
Table No.	1
Date Modified	5/1/2022

Notes:
Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.

Note: These columns are placeholders for future QR submissions.

Table 1: Recent performance on progress metrics

Metric type	**#**	**Progress metric name**	**2015**	**2016**	**2017**	**2018**	**2019**	Q1 **2020**	Q2 **2020**	Q3 **2020**	Q4 **2020**	Q1 **2021**	Q2 **2021**	Q3 **2021**	Q4 **2021**	Q1 **2022**	Q2 **2022**	Q3 **2022**	Q4 **2022**	**Unit(s)**	**Comments**
1. Grid condition findings from inspection - Distribution lines in HFTD	1.a.	Number of circuit miles inspected from patrol inspections in HFTD - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# circuit miles	
	1.b.	Number of circuit miles inspected from detailed inspections in HFTD - Distribution lines	16	140	392	80.9	51.4	0	361	457.7	163	0	67	0	210					# circuit miles	
	1.c.	Number of circuit miles inspected from other inspections (list types of "other" inspections in comments) in HFTD - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# circuit miles	
	1.d.	Level 1 findings in HFTD for patrol inspections - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.e.	Level 1 findings in HFTD for detailed inspections - Distribution lines	0	0	3	0	0	0	19	37	0	0	1	0	8					# findings	
	1.f.	Level 1 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.g.	Level 2 findings in HFTD for patrol inspections - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.h.	Level 2 findings in HFTD for detailed inspections - Distribution lines	0	98	17	8	43	0	316	1102	7	0	7	0	72					# findings	
	1.i.	Level 2 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.j.	Level 3 findings in HFTD for patrol inspections - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.k.	Level 3 findings in HFTD for detailed inspections - Distribution lines	148	728	2375	523	776	0	2895	7020	171	0	83	0	343					# findings	
	1.l.	Level 3 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
1. Grid condition findings from inspection - Distribution lines total	1.a.ii.	Number of total circuit miles inspected from patrol inspections - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# circuit miles	
	1.b.ii.	Number of total circuit miles inspected from detailed inspections - Distribution lines	16	140	392	80.9	51.4	0	361	457.7	163	0	67	0	210					# circuit miles	
	1.c.ii.	Number of total circuit miles inspected from other inspections (list types of "other" inspections in comments) - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# circuit miles	
	1.d.ii.	Level 1 findings for patrol inspections - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.e.ii.	Level 1 findings for detailed inspections - Distribution lines	0	0	3	0	0	0	19	37	0	0	1	0	8					# findings	
	1.f.ii.	Level 1 findings for other inspections (list types of "other" inspections in comments) - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.g.ii.	Level 2 findings for patrol inspections - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.h.ii.	Level 2 findings for detailed inspections - Distribution lines	0	98	17	8	43	0	316	1102	7	0	7	0	72					# findings	
	1.i.ii.	Level 2 findings for other inspections (list types of "other" inspections in comments) - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.j.ii.	Level 3 findings for patrol inspections - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.k.ii.	Level 3 findings for detailed inspections - Distribution lines	148	728	2375	523	776	0	2895	7020	171	0	83	0	343					# findings	
	1.l.ii.	Level 3 findings for other inspections (list types of "other" inspections in comments) - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
1. Grid condition findings from inspection - Transmission lines in HFTD	1.a.iii.	Number of circuit miles inspected from patrol inspections in HFTD - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# circuit miles	
	1.b.iii.	Number of circuit miles inspected from detailed inspections in HFTD - Transmission lines	0	0	47.7	14.5	0	0	6.4	17.1	17.28	0	0	0	0					# circuit miles	
	1.c.iii.	Number of circuit miles inspected from other inspections (list types of "other" inspections in comments) in HFTD - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# circuit miles	
	1.d.iii.	Level 1 findings in HFTD for patrol inspections - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.e.iii.	Level 1 findings in HFTD for detailed inspections - Transmission lines	0	0	0	0	0	0	2	0	0	0	0	0	0					# findings	
	1.f.iii.	Level 1 findings in HFTD for other inspections (list types of "other" inspections in comments) - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.g.iii.	Level 2 findings in HFTD for patrol inspections - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.h.iii.	Level 2 findings in HFTD for detailed inspections - Transmission lines	0	0	0	0	0	0	0	1	0	0	0	0	0					# findings	
	1.i.iii.	Level 2 findings in HFTD for other inspections (list types of "other" inspections in comments) - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.j.iii.	Level 3 findings in HFTD for patrol inspections - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.k.iii.	Level 3 findings in HFTD for detailed inspections - Transmission lines	0	0	386	152	0	0	0	7	19	0	0	0	0					# findings	
	1.l.iii.	Level 3 findings in HFTD for other inspections (list types of "other" inspections in comments) - Distribution lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
1. Grid condition findings from inspection - Transmission lines total	1.a.iv.	Number of total circuit miles inspected from patrol inspections - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# circuit miles	
	1.b.iv.	Number of total circuit miles inspected from detailed inspections - Transmission lines	0	0	47.7	14.5	0	0	6.4	17.1	17.28	0	0	0	0					# circuit miles	
	1.c.iv.	Number of total circuit miles inspected from other inspections (list types of "other" inspections in comments) - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# circuit miles	
	1.d.iv.	Level 1 findings for patrol inspections - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.e.iv.	Level 1 findings for detailed inspections - Transmission lines	0	0	0	0	0	0	2	0	0	0	0	0	0					# findings	
	1.f.iv.	Level 1 findings for other inspections (list types of "other" inspections in comments) - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.g.iv.	Level 2 findings for patrol inspections - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.h.iv.	Level 2 findings for detailed inspections - Transmission lines	0	0	0	0	0	0	0	1	0	0	0	0	0					# findings	
	1.i.iv.	Level 2 findings for other inspections (list types of "other" inspections in comments) - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.j.iv.	Level 3 findings for patrol inspections - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
	1.k.iv.	Level 3 findings for detailed inspections - Transmission lines	0	0	386	152	0	0	0	7	19	0	0	0	0					# findings	
	1.l.iv.	Level 3 findings for other inspections (list types of "other" inspections in comments) - Transmission lines	0	0	0	0	0	0	0	0	0	0	0	0	0					# findings	
2. Vegetation clearance findings from inspection - total	2.a.i	Number of spans insepcted where at least some vegetation was found in non-compliant condition - total	298	294	296	959	1352	190	247	309	1051	142	154	219	1513					# of spans inspected with noncompliant clearance based on applicable rules and regulations at the time of inspection	
	2.a.ii	Number of spans insepcted for vegetation compliance - total	1940	1595	2072	11159	13938	4467	4123	3890	13645	4469	3074	3677	16056					# of spans inspected for vegetation compliance	
2. Vegetation clearance findings from inspection - in HFTD	2.b.i	Number of spans insepcted where at least some vegetation was found in non-compliant condition in HFTD	298	294	296	959	1352	190	247	309	1051	142	154	219	1513					# of spans inspected with noncompliant clearance based on applicable rules and regulations at the time of inspection	
	2.b.ii	Number of spans insepcted for vegetation compliance in HFTD	1940	1595	2072	11159	13938	4467	4123	3890	13645	4469	3074	3677	3056					# of spans inspected for vegetation compliance	
3. Community outreach metrics	3.a.	# Customers in an evacuation zone for utility-ignited wildfire																		# customers (if customer was in an evacuation zone for multiple wildfires, count the customer for each relevant wildfire)	
	3.b.	# Customers notified of evacuation orders																		# customers (count customer multiple times for each unique wildfire of which they were notified)	
	3.c.	% of customers notified of evacuation in evacuation zone of a utility-ignited wildfire																		Percentage of customers notified of evacuation	

Utility	Liberty	**Notes:**
Table No.	2	Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Date Modified	5/1/2022	HWW = High wind warning
		RFW = Red flag warning

Note: These columns are placeholders for future QR submissions.

Table 2: Recent performance on outcome metrics

Metric type	#	Outcome metric name	Wind Warning Status	HFTD Tier	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Risk Events	1.a.	Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events	All	1										0	0	0	0					Number per year	
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	RFW	1										0	0	0	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW	1										0	0	0	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & RFW	1										0	0	0	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & not RFW	1										0	0	0	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	All	2										21	13	9	81						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	RFW	2										0	3	1	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW	2										3	0	0	2						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & RFW	2										0	0	0	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & not RFW	2										3	0	0	2						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	All	3										1	0	0	15						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	RFW	3										0	0	0	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW	3										0	0	0	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & RFW	3										0	0	0	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & not RFW	3										0	0	0	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	All	Non- HFTD										3	1	4	4						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	RFW	Non- HFTD										0	0	1	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW	Non- HFTD										1	0	0	1						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & RFW	Non- HFTD										0	0	0	0						
		Number of all events with probability of ignition, including wires down, contacts with objects, line slap, events with evidence of heat generation, and other events that cause sparking or have the potential to cause ignition	HWW & not RFW	Non- HFTD										1	0	0	1						
1. Risk Events	1.b.	Number of wires down	All	1										0	0	0	0					Number of wires down per year	
		Number of wires down	RFW	1										0	0	0	0						
		Number of wires down	HWW	1										0	0	0	0						
		Number of wires down	HWW & RFW	1										0	0	0	0						
		Number of wires down	HWW & not RFW	1										0	0	0	0						
		Number of wires down	All	2										5	3	2	31						
		Number of wires down	RFW	2										0	1	0	0						
		Number of wires down	HWW	2										0	0	0	1						
		Number of wires down	HWW & RFW	2										0	0	0	0						
		Number of wires down	HWW & not RFW	2										0	0	0	1						
		Number of wires down	All	3										0	0	0	5						
		Number of wires down	RFW	3										0	0	0	0						
		Number of wires down	HWW	3										0	0	0	0						
		Number of wires down	HWW & RFW	3										0	0	0	0						
		Number of wires down	HWW & not RFW	3										0	0	0	0						
		Number of wires down	All	Non- HFTD										0	0	1	1						
		Number of wires down	RFW	Non- HFTD										0	0	1	0						
		Number of wires down	HWW	Non- HFTD										0	0	0	0						
		Number of wires down	HWW & RFW	Non- HFTD										0	0	0	0						
		Number of wires down	HWW & not RFW	Non- HFTD										0	0	0	0						
1. Risk Events	1.c.	Number of outage events not caused by contact with vegetation	All	1										0	0	0	0					Number of outage events per year	
		Number of outage events not caused by contact with vegetation	RFW	1										0	0	0	0						
		Number of outage events not caused by contact with vegetation	HWW	1										0	0	0	0						
		Number of outage events not caused by contact with vegetation	HWW & RFW	1										0	0	0	0						
		Number of outage events not caused by contact with vegetation	HWW & not RFW	1										0	0	0	0						
		Number of outage events not caused by contact with vegetation	All	2										40	35	43	222						
		Number of outage events not caused by contact with vegetation	RFW	2										0	1	1	0						
		Number of outage events not caused by contact with vegetation	HWW	2										1	0	0	18						
		Number of outage events not caused by contact with vegetation	HWW & RFW	2										0	0	0	0						
		Number of outage events not caused by contact with vegetation	HWW & not RFW	2										1	0	0	18						
		Number of outage events not caused by contact with vegetation	All	3										4	1	3	17						
		Number of outage events not caused by contact with vegetation	RFW	3										0	0	0	0						
		Number of outage events not caused by contact with vegetation	HWW	3										2	0	0	0						
		Number of outage events not caused by contact with vegetation	HWW & RFW	3										0	0	0	0						
		Number of outage events not caused by contact with vegetation	HWW & not RFW	3										2	0	0	0						
		Number of outage events not caused by contact with vegetation	All	Non- HFTD										8	3	7	17						
		Number of outage events not caused by contact with vegetation	RFW	Non- HFTD										0	1	1	0						
		Number of outage events not caused by contact with vegetation	HWW	Non- HFTD										1	0	0	0						
		Number of outage events not caused by contact with vegetation	HWW & RFW	Non- HFTD										0	0	0	0						
		Number of outage events not caused by contact with vegetation	HWW & not RFW	Non- HFTD										1	0	0	0						
1. Risk Events	1.d.	Number of outage events caused by contact with vegetation	All	1										0	0	0	0					Number of outage events per year	
		Number of outage events caused by contact with vegetation	RFW	1										0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW	1										0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & RFW	1										0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & not RFW	1										0	0	0	0						
		Number of outage events caused by contact with vegetation	All	2										8	7	3	54						
		Number of outage events caused by contact with vegetation	RFW	2										0	3	1	0						
		Number of outage events caused by contact with vegetation	HWW	2										2	0	0	1						
		Number of outage events caused by contact with vegetation	HWW & RFW	2										0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & not RFW	2										2	0	0	1						
		Number of outage events caused by contact with vegetation	All	3										0	0	0	11						
		Number of outage events caused by contact with vegetation	RFW	3										0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW	3										0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & RFW	3										0	0	0	0						
		Number of outage events caused by contact with vegetation	HWW & not RFW	3										0	0	0	0						

		Number of outage events caused by contact with vegetation	All	Non- HFTD										0	0	0	2
		Number of outage events caused by contact with vegetation	RFW	Non- HFTD										0	0	0	0
		Number of outage events caused by contact with vegetation	HWW	Non- HFTD										0	0	0	1
		Number of outage events caused by contact with vegetation	HWW & RFW	Non- HFTD										0	0	0	0
		Number of outage events caused by contact with vegetation	HWW & not RFW	Non- HFTD										0	0	0	1
2. Utility inspection findings - Distribution	2.a.	Number of Level 1 findings (distribution)	N/A	1						0	0	0	0	0	0	0	0
		Number of Level 1 findings (distribution)	N/A	2						0	47	7	1	0	0	0	7
		Number of Level 1 findings (distribution)	N/A	3						0	1	3	0	0	0	0	0
		Number of Level 1 findings (distribution)	N/A	Non- HFTD						0	13	26	0	0	0	0	0
	2.b.	Number of Level 2 findings (distribution)	N/A	1						0	0	0	0	0	0	0	0
		Number of Level 2 findings (distribution)	N/A	2						0	202	955	6	0	0	0	49
		Number of Level 2 findings (distribution)	N/A	3						0	39	88	0	0	0	0	0
		Number of Level 2 findings (distribution)	N/A	Non- HFTD						0	66	77	3	0	0	0	1
	2.c.	Number of Level 3 findings (distribution)	N/A	1						0	0	0	0	0	0	0	0
		Number of Level 3 findings (distribution)	N/A	2						0	435	1177	23	0	0	0	261
		Number of Level 3 findings (distribution)	N/A	3						0	492	520	0	0	0	0	1
		Number of Level 3 findings (distribution)	N/A	Non- HFTD						0	2086	7143	147	0	0	0	0
	2.d.	Number of distribution circuit miles inspected	N/A	1						0	0	0	0	0	0	0	0
		Number of distribution circuit miles inspected	N/A	2						448.73	448.73	448.73	448.73	448.73	448.73	448.73	448.73
		Number of distribution circuit miles inspected	N/A	3						34.51	34.51	34.51	34.51	34.51	34.51	34.51	34.51
		Number of distribution circuit miles inspected	N/A	Non- HFTD						30.23	30.23	30.23	30.23	30.23	30.23	30.23	30.23
2. Utility inspection findings - Transmission	2.a.ii	Number of Level 1 findings (transmission)	N/A	1													
		Number of Level 1 findings (transmission)	N/A	2													
		Number of Level 1 findings (transmission)	N/A	3													
		Number of Level 1 findings (transmission)	N/A	Non- HFTD													
	2.b.ii	Number of Level 2 findings (transmission)	N/A	1													
		Number of Level 2 findings (transmission)	N/A	2													
		Number of Level 2 findings (transmission)	N/A	3													
		Number of Level 2 findings (transmission)	N/A	Non- HFTD													
	2.c.ii	Number of Level 3 findings (transmission)	N/A	1													
		Number of Level 3 findings (transmission)	N/A	2													
		Number of Level 3 findings (transmission)	N/A	3													
		Number of Level 3 findings (transmission)	N/A	Non- HFTD													
	2.d.ii	Number of transmission circuit miles inspected	N/A	1													
		Number of transmission circuit miles inspected	N/A	2													
		Number of transmission circuit miles inspected	N/A	3													
		Number of transmission circuit miles inspected	N/A	Non- HFTD													
3	3.a.	Fatalities due to utility-related ignitions (total)	N/A	N/A	0	0	0	0	0	0	0	0	0				
	3.b.	Injuries due to utility-related igntions (total)	N/A	N/A	0	0	0	0	0	0	0	0	0				
4. Value of assets destroyed by utility-related ignitions, listed by asset type	4.a.	Value of assets destroyed by utility-related ignitions (total)	N/A	N/A	0	315649	0	0	9855	0	0	0	0				
5. Structures damaged or destroyed by utility-related ignitions	5.a.	Number of structures destroyed by utility-related ignitions (total)	N/A	N/A	0	18	0	0	0	0	0	0	0				
	5.b.	Critical infrastructure damaged/destroyed by utility-rleated ignitions (total)	N/A	N/A	0	0	0	0	0	0	0	0	0				
6. Acreage burned by utility-related ignitions	6.a.	Acreage burned by utility-rleated ignitions	N/A	N/A	10	196	0	0	1	0	0	0	0				
7. Number of utility-related ignitions	7.a.	Number of ignitions (total) according to existing ignition data reporting requirement	N/A	N/A	2	1	0	0	1	0	0	0	2				
	7.b.	Number of ignitions	All	1						0	0	0					
		Number of ignitions	RFW	1						0	0	0					
		Number of ignitions	HWW	1						0	0	0					
		Number of ignitions	HWW & RFW	1						0	0	0					
		Number of ignitions	HWW & not RFW	1						0	0	0					
		Number of ignitions	All	2						0	0	0					
		Number of ignitions	RFW	2						0	0	0					
		Number of ignitions	HWW	2						0	0	0					
		Number of ignitions	HWW & RFW	2						0	0	0					
		Number of ignitions	HWW & not RFW	2						0	0	0					
		Number of ignitions	All	3						0	0	0					
		Number of ignitions	RFW	3						0	0	0					
		Number of ignitions	HWW	3						0	0	0					
		Number of ignitions	HWW & RFW	3						0	0	0					
		Number of ignitions	HWW & not RFW	3						0	0	0					
		Number of ignitions	All	Non- HFTD						0	0	0					
		Number of ignitions	RFW	Non- HFTD						0	0	0					
		Number of ignitions	HWW	Non- HFTD						0	0	0					
		Number of ignitions	HWW & RFW	Non- HFTD						0	0	0					
		Number of ignitions	HWW & not RFW	Non- HFTD						0	0	0					
8. Fatalities resulting from utility wildfire mitigation initiatives	8.a.	Fatalities due to utility wildfire mitigation activities (total) - "activities" defined as all activities accounted for in the 2020 WMP proposed WMP spend	N/A	N/A	0	0	0	0	0	0	0	0	0				
9. OSHA-reportable injuries from utility wildfire mitigation initiatives	9.a.	OSHA-reportable injuries due to utility wildfire mitigation activities (total) - "activities" defined as all activities accounted for in the 2020 WMP proposed WMP spend	N/A	N/A	0	0	0	0	0	0	0	0	0				

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Note: These columns are placeholders for future QR submissions.

Table 3: List and description of additional metrics

Metric	Definition	Purpose	Assumptions made to connect metric to purpose	Third-party validation (if any)	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments

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Note: These columns are placeholders for future QR submissions.

Table 4: Fatalities due to utility wildfire mitigation initiatives

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Fatalities - Full-time Employee	1.a.	Fatalities due to utility inspection - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.b.	Fatalities due to vegetation management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.c.	Fatalities due to utility fuel management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.d.	Fatalities due to grid hardening - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	1.e.	Fatalities due to other - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
2. Fatalities - Contractor	2.a.	Fatalities due to utility inspection - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.b.	Fatalities due to vegetation management - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.c.	Fatalities due to utility fuel management - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.d.	Fatalities due to grid hardening - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	2.e.	Fatalities due to other - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
3. Fatalities - Member of public	3.a.	Fatalities due to utility inspection - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.b.	Fatalities due to vegetation management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.c.	Fatalities due to utility fuel management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.d.	Fatalities due to grid hardening - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	
	3.e.	Fatalities due to other - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# fatalities	

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Note: These columns are placeholders for future QR submissions.

Table 5: OSHA-reportable injuries due to utility wildfire mitigation initiatives

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. OSHA injuries - Full-time Employee	1.a.	OSHA injuries due to utility inspection - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.b.	OSHA injuries due to vegetation management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.c.	OSHA injuries due to utility fuel management - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.d.	OSHA injuries due to grid hardening - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	1.e.	OSHA injuries due to other - Full-time employee	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
2. OSHA injuries - Contractor	2.a.	OSHA injuries due to utility inspection - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.b.	OSHA injuries due to vegetation management - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.c.	OSHA injuries due to utility fuel management - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.d.	OSHA injuries due to grid hardening - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	2.e.	OSHA injuries due to other - Contractor	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
3. OSHA injuries - Member of public	3.a.	OSHA injuries due to utility inspection - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.b.	OSHA injuries due to vegetation management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.c.	OSHA injuries due to utility fuel management - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.d.	OSHA injuries due to grid hardening - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	
	3.e.	OSHA injuries due to other - Public	0	0	0	0	0	0	0	0	0	0	0	0	0					# OSHA-reportable injuries	

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Note: These columns are placeholders for future QR submissions.

Table 6: Weather patterns

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Unit(s)	Comments
1. Red Flag Warning Overhead circuit mile Days	1.a.	Red Flag Warning Overhead circuit mile days - entire utility territory	272	94	193	3134	869	0	101	4679	2093	0	1162	4946	16					Sum of overhead circuit miles of utility grid subject to Red Flag Warning each day within a given time period, calculated as the number of overhead circuit miles that were under an RFW multiplied by the number of days those circuit miles were under said RFW. For example, if 100 overhead circuit miles were under an RFW for 1 day, and 10 of those miles were under RFW for an additional day, then the total RFW OH circuit mile days would be 110.	
	1.b.	Red Flag Warning Overhead circuit mile days - HFTD Zone 1	0	0	0	0	1	0	0	3	2	0	1	0	0					Red Flag Warning Overhead circuit mile days, see above for definition	
	1.c.	Red Flag Warning Overhead circuit mile days - HFTD Tier 2	140	78	118	2593	727	0	99	3822	1737	0	983	4303	15					Red Flag Warning Overhead circuit mile days, see above for definition	
	1.d.	Red Flag Warning Overhead circuit mile days - HFTD Tier 3	0	0	0	306	77	0	0	442	212	0	108	519	0					Red Flag Warning Overhead circuit mile days, see above for definition	
	1.e.	Red Flag Warning Overhead circuit mile days - Non-HFTD	112	14	64	171	48	0	2	313	101	0	71	124	0					Red Flag Warning Overhead circuit mile days, see above for definition	
2. Wind conditions	2.a.	High wind warning overhead circuit mile days	864	3508	180	126	108	11	0	0	862	763	0	0	26					Sum of overhead circuit miles of utility grid subject to High Wind Warnings (HWW, as defined by the National Weather Service) each day within a given time period, calculated as the number of overhead circuit miles that were under an HWW multiplied by the number of days those miles were under said HWW. For example, if 100 overhead circuit miles were under an HWW for 1 day, and 10 of those miles were under HWW for an additional day, then the total HWW OH circuit mile days would be 110.	
3. Other	3.a.	Other relevant weather pattern metrics tracked (add additional rows as needed)																			

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Notes:
Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Data from 2015 - 2021 Q4 should be actual numbers. 2022 Q1 - 2024 should be projected. In future submissions update projected numbers with actuals

Table 7.1: Key recent and projected drivers of risk events

	Risk Event category	Cause category	#	Sub-cause category	Are risk events tracked for ignition driver? (yes / no)	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Unit(s)	Comments
						Number of risk events														Projected risk events								
x	Wire down event - Distribution	1. Contact from object - Distribution	1.a.	Veg. contact- Distribution	Yes	0	1	1	1	0	1	1	2	1	4	1	1	7	2	1	1	1	2	1	1	1	# risk events (excluding ignitions)	
			1.b.	Animal contact- Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			1.c.	Balloon contact- Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			1.d.	Vehicle contact- Distribution	Yes	0	0	0	0	0	0	0	1	0	0	2	1	0	0	0	1	0	0	0	1	0	# risk events (excluding ignitions)	
			1.e.	Other contact from object - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
		2. Equipment / facility failure - Distribution	2.a.	Connector damage or failure- Distribution	Yes	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			2.b.	Splice damage or failure — Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			2.c.	Crossarm damage or failure - Distribution	Yes	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			2.d.	Insulator damage or failure- Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			2.e.	Lightning arrestor damage or failure- Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			2.f.	Tap damage or failure - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			2.g.	Tie wire damage or failure - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			2.h.	Other - Distribution	Yes	0	1	0	0	2	0	0	0	0	0	0	0	0	1	1	0	0	1	1	0	0	# risk events (excluding ignitions)	
		3. Wire-to-wire contact - Distribution	3.a.	Wire-to-wire contact / contamination- Distribution	Yes	0	0	0	0	0	0	0	2	0	0	0	1	0	0	0	1	0	0	0	1	0	# risk events (excluding ignitions)	
		4. Contamination - Distribution	4.a.	Contamination - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
		5. Utility work / Operation	5.a.	Utility work / Operation	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
		6. Vandalism / Theft - Distribution	6.a.	Vandalism / Theft - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
		7. Other- Distribution	7.a.	All Other- Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
		8. Unknown- Distribution	8.a.	Unknown - Distribution	Yes	9	3	1	5	0	0	0	0	0	1	0	0	6	1	0	0	0	1	0	0	0	# risk events (excluding ignitions)	
x	Wire down event - Transmission	9. Contact from object - Transmission	9.a.	Veg. contact- Transmission																							# risk events (excluding ignitions)	
			9.b.	Animal contact- Transmission																							# risk events (excluding ignitions)	
			9.c.	Balloon contact- Transmission																							# risk events (excluding ignitions)	
			9.d.	Vehicle contact- Transmission																							# risk events (excluding ignitions)	
			9.e.	Other contact from object - Transmission																							# risk events (excluding ignitions)	
		10. Equipment / facility failure - Transmission	10.a.	Connector damage or failure- Transmission																							# risk events (excluding ignitions)	
			10.b.	Splice damage or failure — Transmission																							# risk events (excluding ignitions)	
			10.c.	Crossarm damage or failure - Transmission																							# risk events (excluding ignitions)	
			10.d.	Insulator damage or failure- Transmission																							# risk events (excluding ignitions)	
			10.e.	Lightning arrestor damage or failure- Transmission																							# risk events (excluding ignitions)	
			10.f.	Tap damage or failure - Transmission																							# risk events (excluding ignitions)	
			10.g.	Tie wire damage or failure - Transmission																							# risk events (excluding ignitions)	
			10.h.	Other - Transmission																							# risk events (excluding ignitions)	
		11. Wire-to-wire contact - Transmission	11.a.	Wire-to-wire contact / contamination- Transmission																							# risk events (excluding ignitions)	
		12. Contamination - Transmission	12.a.	Contamination - Transmission																							# risk events (excluding ignitions)	
		13. Utility work / Operation	13.a.	Utility work / Operation																							# risk events (excluding ignitions)	
		14. Vandalism / Theft - Transmission	14.a.	Vandalism / Theft - Transmission																							# risk events (excluding ignitions)	
		15. Other- Transmission	15.a.	All Other- Transmission																							# risk events (excluding ignitions)	
		16. Unknown- Transmission	16.a.	Unknown - Transmission																							# risk events (excluding ignitions)	
x	Outage - Distribution	17. Contact from object - Distribution	17.a.	Veg. contact- Distribution	Yes	16	18	14	34	5	7	11	21	5	8	7	10	40	12	10	10	5	12	10	10	5	# risk events (excluding ignitions)	
			17.b.	Animal contact- Distribution	Yes	3	11	2	22	0	1	14	6	1	1	2	6	3	2	6	6	1	2	6	6	1	# risk events (excluding ignitions)	
			17.c.	Balloon contact- Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			17.d.	Vehicle contact- Distribution	Yes	0	10	1	6	8	4	2	7	2	0	4	2	0	0	2	2	2	0	2	2	2	# risk events (excluding ignitions)	
			17.e.	Other contact from object - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
		18. Equipment / facility failure - Distribution	18.a.	Capacitor bank damage or failure- Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			18.b.	Conductor damage or failure — Distribution	Yes	10	5	4	9	3	4	6	16	3	0	5	10	2	3	7	7	3	3	7	7	3	# risk events (excluding ignitions)	
			18.c.	Fuse damage or failure - Distribution	Yes	16	46	50	122	10	9	10	13	15	10	1	15	19	0	15	15	15	0	15	15	15	# risk events (excluding ignitions)	
			18.d.	Lightning arrestor damage or failure- Distribution	Yes	0	1	1	4	0	1	0	1	0	0	1	0	0	0	0	1	0	0	0	1	0	# risk events (excluding ignitions)	
			18.e.	Switch damage or failure- Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			18.f.	Pole damage or failure - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			18.g.	Insulator and brushing damage or failure - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			18.h.	Crossarm damage or failure - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			18.i.	Voltage regulator / booster damage or failure - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			18.j.	Recloser damage or failure - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			18.k.	Anchor / guy damage or failure - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			18.l.	Sectionalizer damage or failure - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			18.m.	Connection device damage or failure - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
			18.n.	Transformer damage or failure - Distribution	Yes	7	13	7	22	2	3	12	15	3	0	4	2	3	1	7	7	3	1	7	7	3	# risk events (excluding ignitions)	
			18.o.	Other - Distribution	Yes	59	23	28	42	8	11	12	22	12	0	8	17	6	3	12	12	12	3	12	12	12	# risk events (excluding ignitions)	
		19. Wire-to-wire contact - Distribution	19.a.	Wire-to-wire contact / contamination- Distribution	Yes	0	2	1	4	6	2	0	3	3	11	0	1	0	7	0	3	3	7	0	3	3	# risk events (excluding ignitions)	
		20. Contamination - Distribution	20.a.	Contamination - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
		21. Utility work / Operation	21.a.	Utility work / Operation	Yes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
		22. Vandalism / Theft - Distribution	22.a.	Vandalism / Theft - Distribution	Yes	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	# risk events (excluding ignitions)	
		23. Other- Distribution	23.a.	All Other- Distribution	Yes	0	0	0	0	14	7	8	22	15	10	2	0	74	0	10	15	15	0	10	15	15	# risk events (excluding ignitions)	
		24. Unknown- Distribution	24.a.	Unknown - Distribution	Yes	0	0	0	0	0	0	0	0	0	20	10	0	99	41	0	0	0	41	0	0	0	# risk events (excluding ignitions)	
x	Outage - Transmission	25. Contact from object - Transmission	25.a.	Veg. contact- Transmission																							# risk events (excluding ignitions)	
			25.b.	Animal contact- Transmission																							# risk events (excluding ignitions)	
			25.c.	Balloon contact- Transmission																							# risk events (excluding ignitions)	
			25.d.	Vehicle contact- Transmission																							# risk events (excluding ignitions)	
			25.e.	Other contact from object - Transmission																							# risk events (excluding ignitions)	
		26. Equipment / facility failure - Transmission	26.a.	Capacitor bank damage or failure- Transmission																							# risk events (excluding ignitions)	
			26.b.	Conductor damage or failure — Transmission																							# risk events (excluding ignitions)	
			26.c.	Fuse damage or failure - Transmission																							# risk events (excluding ignitions)	
			26.d.	Lightning arrestor damage or failure- Transmission																							# risk events (excluding ignitions)	
			26.e.	Switch damage or failure- Transmission																							# risk events (excluding ignitions)	
			26.f.	Pole damage or failure - Transmission																							# risk events (excluding ignitions)	
			26.g.	Insulator and brushing damage or failure - Transmission																							# risk events (excluding ignitions)	
			26.h.	Crossarm damage or failure - Transmission																							# risk events (excluding ignitions)	
			26.i.	Voltage regulator / booster damage or failure - Transmission																							# risk events (excluding ignitions)	
			26.j.	Recloser damage or failure - Transmission																							# risk events (excluding ignitions)	
			26.k.	Anchor / guy damage or failure - Transmission																							# risk events (excluding ignitions)	
			26.l.	Sectionalizer damage or failure - Transmission																							# risk events (excluding ignitions)	
			26.m.	Connection device damage or failure - Transmission																							# risk events (excluding ignitions)	
			26.n.	Transformer damage or failure - Transmission																							# risk events (excluding ignitions)	
			26.o.	Other - Transmission																							# risk events (excluding ignitions)	
		27. Wire-to-wire contact - Transmission	27.a.	Wire-to-wire contact / contamination- Transmission																							# risk events (excluding ignitions)	
		28. Contamination - Transmission	28.a.	Contamination - Transmission																							# risk events (excluding ignitions)	
		29. Utility work / Operation	29.a.	Utility work / Operation																							# risk events (excluding ignitions)	
		30. Vandalism / Theft - Transmission	30.a.	Vandalism / Theft - Transmission																							# risk events (excluding ignitions)	
		31. Other- Transmission	31.a.	All Other- Transmission																							# risk events (excluding ignitions)	
		32. Unknown- Transmission	32.a.	Unknown - Transmission																							# risk events (excluding ignitions)	

Utility	Liberty
Table No.	7.2
Date Modified	5/1/2022

Notes:
Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
Data from 2015 - 2021 should be actual numbers. 2022 and 2023 should be projected. In future submissions update projected numbers with actuals

Table 7.2: Key recent and projected drivers of ignitions

x

						Number of ignitions								Projected ignitions		
Metric type	**#**	**Ignition driver**	**Line Type**	**HFTD tier**	**Are ignitions tracked for ignition driver? (yes / no)**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Unit(s)**	**Comments**
1. Contact from object	1.a.i	Veg. contact	Distribution	Non-HFTD	Yes				0	0	0	0	0		# ignitions	
	1.a.ii	Veg. contact	Distribution	HFTD Zone 1	Yes				0	0	0	0	0		# ignitions	
	1.a.iii	Veg. contact	Distribution	HFTD Tier 2	Yes				0	1	3	4	0		# ignitions	
	1.a.iv	Veg. contact	Distribution	HFTD Tier 3	Yes				0	0	0	0	0		# ignitions	
	1.a.v	Veg. contact	Distribution	System	Yes				0	1	3	4	0		# ignitions	
	1.a.vi	Veg. contact	Transmission	Non-HFTD											# ignitions	
	1.a.vii	Veg. contact	Transmission	HFTD Zone 1											# ignitions	
	1.a.viii	Veg. contact	Transmission	HFTD Tier 2								2			# ignitions	
	1.a.ix	Veg. contact	Transmission	HFTD Tier 3											# ignitions	
	1.a.x	Veg. contact	Transmission	System											# ignitions	
	1.b.i	Animal contact	Distribution	Non-HFTD	Yes				0	0	0	0	0		# ignitions	
	1.b.ii	Animal contact	Distribution	HFTD Zone 1	Yes				0	0	0	0	0		# ignitions	
	1.b.iii	Animal contact	Distribution	HFTD Tier 2	Yes				0	0	0	0	0		# ignitions	
	1.b.iv	Animal contact	Distribution	HFTD Tier 3	Yes				0	0	0	0	0		# ignitions	
	1.b.v	Animal contact	Distribution	System	Yes				0	0	0	0	0		# ignitions	
	1.b.vi	Animal contact	Transmission	Non-HFTD											# ignitions	
	1.b.vii	Animal contact	Transmission	HFTD Zone 1											# ignitions	
	1.b.viii	Animal contact	Transmission	HFTD Tier 2											# ignitions	
	1.b.ix	Animal contact	Transmission	HFTD Tier 3											# ignitions	
	1.b.x	Animal contact	Transmission	System											# ignitions	
	1.c.i	Balloon contact	Distribution	Non-HFTD	Yes				0	0	0	0	0		# ignitions	
	1.c.ii	Balloon contact	Distribution	HFTD Zone 1	Yes				0	0	0	0	0		# ignitions	
	1.c.iii	Balloon contact	Distribution	HFTD Tier 2	Yes				0	0	0	0	0		# ignitions	
	1.c.iv	Balloon contact	Distribution	HFTD Tier 3	Yes				0	0	0	0	0		# ignitions	
	1.c.v	Balloon contact	Distribution	System	Yes				0	0	0	0	0		# ignitions	
	1.c.vi	Balloon contact	Transmission	Non-HFTD											# ignitions	
	1.c.vii	Balloon contact	Transmission	HFTD Zone 1											# ignitions	
	1.c.viii	Balloon contact	Transmission	HFTD Tier 2											# ignitions	
	1.c.ix	Balloon contact	Transmission	HFTD Tier 3											# ignitions	
	1.c.x	Balloon contact	Transmission	System											# ignitions	
	1.d.i	Vehicle contact	Distribution	Non-HFTD	Yes				0	0	0	0	0		# ignitions	
	1.d.ii	Vehicle contact	Distribution	HFTD Zone 1	Yes				0	0	0	0	0		# ignitions	
	1.d.iii	Vehicle contact	Distribution	HFTD Tier 2	Yes				0	0	0	1	0		# ignitions	
	1.d.iv	Vehicle contact	Distribution	HFTD Tier 3	Yes				0	0	0	0	0		# ignitions	
	1.d.v	Vehicle contact	Distribution	System	Yes				0	0	0	1	0		# ignitions	
	1.d.vi	Vehicle contact	Transmission	Non-HFTD											# ignitions	
	1.d.vii	Vehicle contact	Transmission	HFTD Zone 1											# ignitions	
	1.d.viii	Vehicle contact	Transmission	HFTD Tier 2											# ignitions	
	1.d.ix	Vehicle contact	Transmission	HFTD Tier 3											# ignitions	
	1.d.x	Vehicle contact	Transmission	System											# ignitions	
	1.e.i	Other contact from object	Distribution	Non-HFTD	Yes				0	0	0	0	0		# ignitions	
	1.e.ii	Other contact from object	Distribution	HFTD Zone 1	Yes				0	0	0	0	0		# ignitions	
	1.e.iii	Other contact from object	Distribution	HFTD Tier 2	Yes				0	0	0	0	0		# ignitions	
	1.e.iv	Other contact from object	Distribution	HFTD Tier 3	Yes				0	0	0	0	0		# ignitions	
	1.e.v	Other contact from object	Distribution	System	Yes				0	0	0	0	0		# ignitions	
	1.e.vi	Other contact from object	Transmission	Non-HFTD											# ignitions	
	1.e.vii	Other contact from object	Transmission	HFTD Zone 1											# ignitions	
	1.e.viii	Other contact from object	Transmission	HFTD Tier 2											# ignitions	
	1.e.ix	Other contact from object	Transmission	HFTD Tier 3											# ignitions	
	1.e.x	Other contact from object	Transmission	System											# ignitions	
2. Equipment / facility failure	2.a.i	Capacitor bank damage or failure	Distribution	Non-HFTD	Yes				0	0	0	0	0		# ignitions	
	2.a.ii	Capacitor bank damage or failure	Distribution	HFTD Zone 1	Yes				0	0	0	0	0		# ignitions	
	2.a.iii	Capacitor bank damage or failure	Distribution	HFTD Tier 2	Yes				0	0	0	0	0		# ignitions	
	2.a.iv	Capacitor bank damage or failure	Distribution	HFTD Tier 3	Yes				0	0	0	0	0		# ignitions	
	2.a.v	Capacitor bank damage or failure	Distribution	System	Yes				0	0	0	0	0		# ignitions	
	2.a.vi	Capacitor bank damage or failure	Transmission	Non-HFTD											# ignitions	
	2.a.vii	Capacitor bank damage or failure	Transmission	HFTD Zone 1											# ignitions	
	2.a.viii	Capacitor bank damage or failure	Transmission	HFTD Tier 2											# ignitions	
	2.a.ix	Capacitor bank damage or failure	Transmission	HFTD Tier 3											# ignitions	
	2.a.x	Capacitor bank damage or failure	Transmission	System											# ignitions	
	2.b.i	Conductor damage or failure	Distribution	Non-HFTD	Yes				0	0	0	0	0		# ignitions	
	2.b.ii	Conductor damage or failure	Distribution	HFTD Zone 1	Yes				0	0	0	0	0		# ignitions	

2.b.iii	Conductor damage or failure	Distribution	HFTD Tier 2	Yes	0	0	1	1	0	# ignitions
2.b.iv	Conductor damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
2.b.v	Conductor damage or failure	Distribution	System	Yes	0	0	1	1	0	# ignitions
2.b.vi	Conductor damage or failure	Transmission	Non-HFTD							# ignitions
2.b.vii	Conductor damage or failure	Transmission	HFTD Zone 1							# ignitions
2.b.viii	Conductor damage or failure	Transmission	HFTD Tier 2							# ignitions
2.b.ix	Conductor damage or failure	Transmission	HFTD Tier 3							# ignitions
2.b.x	Conductor damage or failure	Transmission	System							# ignitions
2.c.i	Fuse damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
2.c.ii	Fuse damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
2.c.iii	Fuse damage or failure	Distribution	HFTD Tier 2	Yes	1	2	2	0	0	# ignitions
2.c.iv	Fuse damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
2.c.v	Fuse damage or failure	Distribution	System	Yes	0	2	2	0	0	# ignitions
2.c.vi	Fuse damage or failure	Transmission	Non-HFTD							# ignitions
2.c.vii	Fuse damage or failure	Transmission	HFTD Zone 1							# ignitions
2.c.viii	Fuse damage or failure	Transmission	HFTD Tier 2							# ignitions
2.c.ix	Fuse damage or failure	Transmission	HFTD Tier 3							# ignitions
2.c.x	Fuse damage or failure	Transmission	System							# ignitions
2.d.i	Lightning arrestor damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
2.d.ii	Lightning arrestor damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
2.d.iii	Lightning arrestor damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions
2.d.iv	Lightning arrestor damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
2.d.v	Lightning arrestor damage or failure	Distribution	System	Yes	0	0	0	0	0	# ignitions
2.d.vi	Lightning arrestor damage or failure	Transmission	Non-HFTD							# ignitions
2.d.vii	Lightning arrestor damage or failure	Transmission	HFTD Zone 1							# ignitions
2.d.viii	Lightning arrestor damage or failure	Transmission	HFTD Tier 2							# ignitions
2.d.ix	Lightning arrestor damage or failure	Transmission	HFTD Tier 3							# ignitions
2.d.x	Lightning arrestor damage or failure	Transmission	System							# ignitions
2.e.i	Switch damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
2.e.ii	Switch damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
2.e.iii	Switch damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions
2.e.iv	Switch damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
2.e.v	Switch damage or failure	Distribution	System	Yes	0	0	0	0	0	# ignitions
2.e.vi	Switch damage or failure	Transmission	Non-HFTD							# ignitions
2.e.vii	Switch damage or failure	Transmission	HFTD Zone 1							# ignitions
2.e.viii	Switch damage or failure	Transmission	HFTD Tier 2							# ignitions
2.e.ix	Switch damage or failure	Transmission	HFTD Tier 3							# ignitions
2.e.x	Switch damage or failure	Transmission	System							# ignitions
2.f.i	Pole damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
2.f.ii	Pole damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
2.f.iii	Pole damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	3	0	# ignitions
2.f.iv	Pole damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
2.f.v	Pole damage or failure	Distribution	System	Yes	0	0	0	3	0	# ignitions
2.f.vi	Pole damage or failure	Transmission	Non-HFTD							# ignitions
2.f.vii	Pole damage or failure	Transmission	HFTD Zone 1							# ignitions
2.f.viii	Pole damage or failure	Transmission	HFTD Tier 2							# ignitions
2.f.ix	Pole damage or failure	Transmission	HFTD Tier 3							# ignitions
2.f.x	Pole damage or failure	Transmission	System							# ignitions
2.g.i	Insulator and brushing damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
2.g.ii	Insulator and brushing damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
2.g.iii	Insulator and brushing damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions
2.g.iv	Insulator and brushing damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
2.g.v	Insulator and brushing damage or failure	Distribution	System	Yes	0	0	0	0	0	# ignitions
2.g.vi	Insulator and brushing damage or failure	Transmission	Non-HFTD							# ignitions
2.g.vii	Insulator and brushing damage or failure	Transmission	HFTD Zone 1							# ignitions
2.g.viii	Insulator and brushing damage or failure	Transmission	HFTD Tier 2							# ignitions
2.g.ix	Insulator and brushing damage or failure	Transmission	HFTD Tier 3							# ignitions
2.g.x	Insulator and brushing damage or failure	Transmission	System							# ignitions
2.h.i	Crossarm damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
2.h.ii	Crossarm damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
2.h.iii	Crossarm damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	1	0	# ignitions
2.h.iv	Crossarm damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
2.h.v	Crossarm damage or failure	Distribution	System	Yes	0	0	0	1	0	# ignitions
2.h.vi	Crossarm damage or failure	Transmission	Non-HFTD							# ignitions
2.h.vii	Crossarm damage or failure	Transmission	HFTD Zone 1							# ignitions
2.h.viii	Crossarm damage or failure	Transmission	HFTD Tier 2							# ignitions
2.h.ix	Crossarm damage or failure	Transmission	HFTD Tier 3							# ignitions
2.h.x	Crossarm damage or failure	Transmission	System							# ignitions
2.i.i	Voltage regulator / booster damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions

2.i.ii	Voltage regulator / booster damage or failure	Distribution	HFTD Zone 1	Yes		0	0	0	0	0		# ignitions
2.i.iii	Voltage regulator / booster damage or failure	Distribution	HFTD Tier 2	Yes		0	0	0	0	0		# ignitions
2.i.iv	Voltage regulator / booster damage or failure	Distribution	HFTD Tier 3	Yes		0	0	0	0	0		# ignitions
2.i.v	Voltage regulator / booster damage or failure	Distribution	System	Yes		0	0	0	0	0		# ignitions
2.i.vi	Voltage regulator / booster damage or failure	Transmission	Non-HFTD									# ignitions
2.i.vii	Voltage regulator / booster damage or failure	Transmission	HFTD Zone 1									# ignitions
2.i.viii	Voltage regulator / booster damage or failure	Transmission	HFTD Tier 2									# ignitions
2.i.ix	Voltage regulator / booster damage or failure	Transmission	HFTD Tier 3									# ignitions
2.i.x	Voltage regulator / booster damage or failure	Transmission	System									# ignitions

	2.j.i	Recloser damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
	2.j.ii	Recloser damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
	2.j.iii	Recloser damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions
	2.j.iv	Recloser damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
	2.j.v	Recloser damage or failure	Distribution	System	Yes	0	0	0	0	0	# ignitions
	2.j.vi	Recloser damage or failure	Transmission	Non-HFTD							# ignitions
	2.j.vii	Recloser damage or failure	Transmission	HFTD Zone 1							# ignitions
	2.j.viii	Recloser damage or failure	Transmission	HFTD Tier 2							# ignitions
	2.j.ix	Recloser damage or failure	Transmission	HFTD Tier 3							# ignitions
	2.j.x	Recloser damage or failure	Transmission	System							# ignitions
	2.k.i	Anchor / guy damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
	2.k.ii	Anchor / guy damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
	2.k.iii	Anchor / guy damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions
	2.k.iv	Anchor / guy damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
	2.k.v	Anchor / guy damage or failure	Distribution	System	Yes	0	0	0	0	0	# ignitions
	2.k.vi	Anchor / guy damage or failure	Transmission	Non-HFTD							# ignitions
	2.k.vii	Anchor / guy damage or failure	Transmission	HFTD Zone 1							# ignitions
	2.k.viii	Anchor / guy damage or failure	Transmission	HFTD Tier 2							# ignitions
	2.k.ix	Anchor / guy damage or failure	Transmission	HFTD Tier 3							# ignitions
	2.k.x	Anchor / guy damage or failure	Transmission	System							# ignitions
	2.l.i	Sectionalizer damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
	2.l.ii	Sectionalizer damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
	2.l.iii	Sectionalizer damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions
	2.l.iv	Sectionalizer damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
	2.l.v	Sectionalizer damage or failure	Distribution	System	Yes	0	0	0	0	0	# ignitions
	2.l.vi	Sectionalizer damage or failure	Transmission	Non-HFTD							# ignitions
	2.l.vii	Sectionalizer damage or failure	Transmission	HFTD Zone 1							# ignitions
	2.l.viii	Sectionalizer damage or failure	Transmission	HFTD Tier 2							# ignitions
	2.l.ix	Sectionalizer damage or failure	Transmission	HFTD Tier 3							# ignitions
	2.l.x	Sectionalizer damage or failure	Transmission	System							# ignitions
	2.m.i	Connection device damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
	2.m.ii	Connection device damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
	2.m.iii	Connection device damage or failure	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions
	2.m.iv	Connection device damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
	2.m.v	Connection device damage or failure	Distribution	System	Yes	0	0	0	0	0	# ignitions
	2.m.vi	Connection device damage or failure	Transmission	Non-HFTD							# ignitions
	2.m.vii	Connection device damage or failure	Transmission	HFTD Zone 1							# ignitions
	2.m.viii	Connection device damage or failure	Transmission	HFTD Tier 2							# ignitions
	2.m.ix	Connection device damage or failure	Transmission	HFTD Tier 3							# ignitions
	2.m.x	Connection device damage or failure	Transmission	System							# ignitions
	2.n.i	Transformer damage or failure	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
	2.n.ii	Transformer damage or failure	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
	2.n.iii	Transformer damage or failure	Distribution	HFTD Tier 2	Yes	2	0	2	0	0	# ignitions
	2.n.iv	Transformer damage or failure	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
	2.n.v	Transformer damage or failure	Distribution	System	Yes	2	0	2	0	0	# ignitions
	2.n.vi	Transformer damage or failure	Transmission	Non-HFTD							# ignitions
	2.n.vii	Transformer damage or failure	Transmission	HFTD Zone 1							# ignitions
	2.n.viii	Transformer damage or failure	Transmission	HFTD Tier 2							# ignitions
	2.n.ix	Transformer damage or failure	Transmission	HFTD Tier 3							# ignitions
	2.n.x	Transformer damage or failure	Transmission	System							# ignitions
	2.o.i	Other	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
	2.o.ii	Other	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
	2.o.iii	Other	Distribution	HFTD Tier 2	Yes	2	6	5	3	0	# ignitions
	2.o.iv	Other	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
	2.o.v	Other	Distribution	System	Yes	2	6	5	3	0	# ignitions
	2.o.vi	Other	Transmission	Non-HFTD							# ignitions
	2.o.vii	Other	Transmission	HFTD Zone 1							# ignitions
	2.o.viii	Other	Transmission	HFTD Tier 2							# ignitions
	2.o.ix	Other	Transmission	HFTD Tier 3							# ignitions
	2.o.x	Other	Transmission	System							# ignitions
3. Wire-to-wire contact	3.a.i	Wire-to-wire contact / contamination	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions
	3.a.ii	Wire-to-wire contact / contamination	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions
	3.a.iii	Wire-to-wire contact / contamination	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions
	3.a.iv	Wire-to-wire contact / contamination	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions
	3.a.v	Wire-to-wire contact / contamination	Distribution	System	Yes	0	0	0	0	0	# ignitions
	3.a.vi	Wire-to-wire contact / contamination	Transmission	Non-HFTD							# ignitions
	3.a.vii	Wire-to-wire contact / contamination	Transmission	HFTD Zone 1							# ignitions
	3.a.viii	Wire-to-wire contact / contamination	Transmission	HFTD Tier 2							# ignitions
	3.a.ix	Wire-to-wire contact / contamination	Transmission	HFTD Tier 3							# ignitions

	3.a.x	Wire-to-wire contact / contamination	Transmission	System							# ignitions	
4. Contamination	4.a.i	Contamination	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions	
	4.a.ii	Contamination	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions	
	4.a.iii	Contamination	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions	
	4.a.iv	Contamination	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions	
	4.a.v	Contamination	Distribution	System	Yes	0	0	0	0	0	# ignitions	
	4.a.vi	Contamination	Transmission	Non-HFTD							# ignitions	
	4.a.vii	Contamination	Transmission	HFTD Zone 1							# ignitions	
	4.a.viii	Contamination	Transmission	HFTD Tier 2							# ignitions	
	4.a.ix	Contamination	Transmission	HFTD Tier 3							# ignitions	
	4.a.x	Contamination	Transmission	System							# ignitions	
5. Utility work / Operation	5.a.i	Utility work / Operation	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions	
	5.a.ii	Utility work / Operation	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions	
	5.a.iii	Utility work / Operation	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions	
	5.a.iv	Utility work / Operation	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions	
	5.a.v	Utility work / Operation	Distribution	System	Yes	0	0	0	0	0	# ignitions	
	5.a.vi	Utility work / Operation	Transmission	Non-HFTD							# ignitions	
	5.a.vii	Utility work / Operation	Transmission	HFTD Zone 1							# ignitions	
	5.a.viii	Utility work / Operation	Transmission	HFTD Tier 2							# ignitions	
	5.a.ix	Utility work / Operation	Transmission	HFTD Tier 3							# ignitions	
	5.a.x	Utility work / Operation	Transmission	System							# ignitions	
6. Vandalism / Theft	6.a.i	Vandalism / Theft	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions	
	6.a.ii	Vandalism / Theft	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions	
	6.a.iii	Vandalism / Theft	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions	
	6.a.iv	Vandalism / Theft	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions	
	6.a.v	Vandalism / Theft	Distribution	System	Yes	0	0	0	0	0	# ignitions	
	6.a.vi	Vandalism / Theft	Transmission	Non-HFTD							# ignitions	
	6.a.vii	Vandalism / Theft	Transmission	HFTD Zone 1							# ignitions	
	6.a.viii	Vandalism / Theft	Transmission	HFTD Tier 2							# ignitions	
	6.a.ix	Vandalism / Theft	Transmission	HFTD Tier 3							# ignitions	
	6.a.x	Vandalism / Theft	Transmission	System							# ignitions	
7. Other	7.a.i	All Other	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions	
	7.a.ii	All Other	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions	
	7.a.iii	All Other	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions	
	7.a.iv	All Other	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions	
	7.a.v	All Other	Distribution	System	Yes	0	0	0	0	0	# ignitions	
	7.a.vi	All Other	Transmission	Non-HFTD							# ignitions	
	7.a.vii	All Other	Transmission	HFTD Zone 1							# ignitions	
	7.a.viii	All Other	Transmission	HFTD Tier 2							# ignitions	
	7.a.ix	All Other	Transmission	HFTD Tier 3							# ignitions	
	7.a.x	All Other	Transmission	System							# ignitions	
8. Unknown	8.a.i	Unknown	Distribution	Non-HFTD	Yes	0	0	0	0	0	# ignitions	
	8.a.ii	Unknown	Distribution	HFTD Zone 1	Yes	0	0	0	0	0	# ignitions	
	8.a.iii	Unknown	Distribution	HFTD Tier 2	Yes	0	0	0	0	0	# ignitions	
	8.a.iv	Unknown	Distribution	HFTD Tier 3	Yes	0	0	0	0	0	# ignitions	
	8.a.v	Unknown	Distribution	System	Yes	0	0	0	0	0	# ignitions	
	8.a.vi	Unknown	Transmission	Non-HFTD							# ignitions	
	8.a.vii	Unknown	Transmission	HFTD Zone 1							# ignitions	
	8.a.viii	Unknown	Transmission	HFTD Tier 2							# ignitions	
	8.a.ix	Unknown	Transmission	HFTD Tier 3							# ignitions	
	8.a.x	Unknown	Transmission	System							# ignitions	

Utility	Liberty
Table No.	8
Date Modified	5/1/2022

Table 8: State of service territory and utility equipment

	Metric type	#	Outcome metric name	Non-HFTD 2015	HFTD Zone 1 2015	HFTD Tier 2 2015	HFTD Tier 3 2015	Non-HFTD 2016	HFTD Zone 1 2016	HFTD Tier 2 2016	HFTD Tier 3 2016	Non-HFTD 2017	HFTD Zone 1 2017	HFTD Tier 2 2017	HFTD Tier 3 2017	Non-HFTD 2018	HFTD Zone 1 2018	HFTD Tier 2 2018	HFTD Tier 3 2018	Non-HFTD 2019	HFTD Zone 1 2019	HFTD Tier 2 2019	HFTD Tier 3 2019	Non-HFTD 2020	HFTD Zone 1 2020	HFTD Tier 2 2020	HFTD Tier 3 2020	Non-HFTD 2021	HFTD Zone 1 2021	HFTD Tier 2 2021	HFTD Tier 3 2021	Non-HFTD 2022	HFTD Zone 1 2022	HFTD Tier 2 2022	HFTD Tier 3 2022	Unit(s)	Comments
x	1. State of service territory and equipment in urban areas	1.a.	Circuit miles (including WUI and non-WUI)																					30	0	429	0	29	0	428	0	29	0	428	0	Circuit miles	
		1.b.	Circuit miles in WUI																					27	0	401	0	27	0	400	0	27	0	400	0	Circuit miles in WUI	
		1.c.	Number of critical facilities (including WUI and non-WUI)																					0	0	138	3	0	0	21	0	0	0	21	0	Number of critical facilities	
		1.d.	Number of critical facilities in WUI																					0	0	79	3	0	0	17	0	0	0	17	0	Number of critical facilities in WUI	
		1.e.	Number of customers (including WUI and non-WUI)																					1214	0	16521	1	1214	0	16521	1	1214	0	16521	1	Number of customers	
		1.f.	Number of customers in WUI																					1191	0	16194	1	1191	0	16194	1	1191	0	16194	1	Number of customers in WUI	
		1.g.	Number of customers belonging to access and functional needs populations (including WUI and non-WUI)																					5	0	124	0	5	0	125	0	5	0	125	0	Number of customers belonging to access and functional needs populations	
		1.h.	Number of customers belonging to access and functional needs populations in WUI																					4	0	123	0	5	0	124	0	5	0	124	0	Number of customers belonging to access and functional needs populations in WUI	
		1.i.	Circuit miles of overhead transmission lines (including WUI and non-WUI)																					1	0	1	0	1	0	1	0	1	0	1	0	Circuit miles of overhead transmission lines	
		1.j.	Circuit miles of overhead transmission lines in WUI																					0	0	1	0	0	0	1	0	0	0	1	0	Circuit miles of overhead transmission lines in WUI	
		1.k.	Circuit miles of overhead distribution lines (including WUI and non-WUI)																					6	0	324	0	6	0	323	0	6	0	323	0	Circuit miles of overhead distribution lines	
		1.l.	Circuit miles of overhead distribution lines in WUI																					5	0	306	0	5	0	306	0	5	0	306	0	Circuit miles of overhead distribution lines in WUI	
		1.m.	Number of substations (including WUI and non-WUI)																					0	0	3	0	0	0	2	0	0	0	2	0	Number of substations	
		1.n	Number of substations in WUI																					0	0	2	0	0	0	1	0	0	0	1	0	Number of substations in WUI	
		1.o.	Number of weather stations (including WUI and non-WUI)																					0	0	1	0	0	0	1	0	0	0	1	0	Number of weather stations	
		1.p.	Number of weather stations in WUI																					0	0	0	0	0	0	0	0	0	0	0	0	Number of weather stations in WUI	
x	2. State of service territory and equipment in rural areas	2.a.	Circuit miles (including WUI and non-WUI)																					24	0	1135	136	24	0	1127	136	24	0	1127	136	Circuit miles	
		2.b.	Circuit miles in WUI																					16	0	874	116	16	0	870	116	16	0	870	116	Circuit miles in WUI	
		2.c.	Number of critical facilities (including WUI and non-WUI)																					0	0	138	1	3	0	38	3	3	0	38	3	Number of critical facilities	
		2.d.	Number of critical facilities in WUI																					0	0	49	1	1	0	29	3	1	0	29	3	Number of critical facilities in WUI	
		2.e.	Number of customers (including WUI and non-WUI)																					574	0	23260	2961	574	0	23260	2961	574	0	23260	2961	Number of customers	
		2.f.	Number of customers in WUI																					447	0	21705	2816	447	0	21705	2816	447	0	21705	2816	Number of customers in WUI	
		2.g.	Number of customers belonging to access and functional needs populations (including WUI and non-WUI)																					3	0	34	24	4	0	38	23	4	0	38	23	Number of customers belonging to access and functional needs populations	
		2.h.	Number of customers belonging to access and functional needs populations in WUI																					3	0	32	20	4	0	35	21	4	0	35	21	Number of customers belonging to access and functional needs populations in WUI	
		2.i.	Circuit miles of overhead transmission lines (including WUI and non-WUI)																					0	0	15	2	0	0	15	2	0	0	15	2	Circuit miles of overhead transmission lines	
		2.j.	Circuit miles of overhead transmission lines in WUI																					0	0	3	0	0	0	3	0	0	0	3	0	Circuit miles of overhead transmission lines in WUI	
		2.k.	Circuit miles of overhead distribution lines (including WUI and non-WUI)																					19	0	757	123	19	0	751	123	19	0	751	123	Circuit miles of overhead distribution lines	
		2.l.	Circuit miles of overhead distribution lines in WUI																					13	0	583	108	13	0	581	107	13	0	581	107	Circuit miles of overhead distribution lines in WUI	
		2.m.	Number of substations (including WUI and non-WUI)																					0	0	7	1	0	0	7	1	0	0	6	1	Number of substations	
		2.n	Number of substations in WUI																					0	0	3	0	0	0	3	0	0	0	3	0	Number of substations in WUI	
		2.o.	Number of weather stations (including WUI and non-WUI)																					0	0	15	1	0	0	15	1	0	0	15	1	Number of weather stations	
		2.p.	Number of weather stations in WUI																					0	0	0	0	0	0	0	0	0	0	0	0	Number of weather stations in WUI	
x	3. State of service territory and equipment in highly rural areas	3.a.	Circuit miles (including WUI and non-WUI)																					79	0	228	0	78	0	227	0	78	0	227	0	Circuit miles	
		3.b.	Circuit miles in WUI																					61	0	146	0	61	0	146	0	61	0	146	0	Circuit miles in WUI	
		3.c.	Number of critical facilities (including WUI and non-WUI)																					0	0	138	0	15	0	21	0	15	0	21	0	Number of critical facilities	
		3.d.	Number of critical facilities in WUI																					0	0	6	0	12	0	11	0	12	0	11	0	Number of critical facilities in WUI	
		3.e.	Number of customers (including WUI and non-WUI)																					1921	0	2468	0	1921	0	2468	0	1921	0	2468	0	Number of customers	
		3.f.	Number of customers in WUI																					1764	0	2113	0	1764	0	2113	0	1764	0	2113	0	Number of customers in WUI	
		3.g.	Number of customers belonging to access and functional needs populations (including WUI and non-WUI)																					38	0	30	0	42	0	23	0	42	0	23	0	Number of customers belonging to access and functional needs populations	
		3.h.	Number of customers belonging to access and functional needs populations in WUI																					37	0	30	0	40	0	23	0	40	0	23	0	Number of customers belonging to access and functional needs populations in WUI	
		3.i.	Circuit miles of overhead transmission lines (including WUI and non-WUI)																					0	0	0	0	0	0	0	0	0	0	0	0	Circuit miles of overhead transmission lines	
		3.j.	Circuit miles of overhead transmission lines in WUI																					0	0	0	0	0	0	0	0	0	0	0	0	Circuit miles of overhead transmission lines in WUI	
		3.k.	Circuit miles of overhead distribution lines (including WUI and non-WUI)																					70	0	184	0	68	0	184	0	68	0	184	0	Circuit miles of overhead distribution lines	
		3.l.	Circuit miles of overhead distribution lines in WUI																					54	0	112	0	52	0	112	0	52	0	112	0	Circuit miles of overhead distribution lines in WUI	
		3.m.	Number of substations (including WUI and non-WUI)																					1	0	2	0	1	0	2	0	1	0	2	0	Number of substations	
		3.n	Number of substations in WUI																					1	0	1	0	1	0	1	0	1	0	1	0	Number of substations in WUI	
		3.o.	Number of weather stations (including WUI and non-WUI)																					3	0	9	0	3	0	9	0	3	0	9	0	Number of weather stations	
		3.p.	Number of weather stations in WUI																					0	0	5	0	0	0	5	0	0	0	5	0	Number of weather stations in WUI	

Utility	Liberty	Notes:
Table No.	9	Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV. Report net additions using positive numbers and net removals and undergrounding using negative numbers for circuit miles and numbers of substations. Only report changes expected within the target year.
Date Modified	5/1/2022	For example, if 20 net overhead circuit miles are planned for addition by 2023, with 15 being added by 2022 and 5 more added by 2023, then report "15" for 2022 and "5" for 2023. Do not report cumulative change across years. In this case, do not report "20" for 2023, but instead the number planned to be added for just that year, which is "5".

Table 9: Location of actual and planned utility equipment additions or removal year over year

				Actual													
				Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3		
	Metric type	**#**	**Outcome metric name**	**2020**	**2020**	**2020**	**2020**	**2021**	**2021**	**2021**	**2021**	**2022**	**2022**	**2022**	**2022**	**Unit(s)**	**Comments**
x	1. Planned utility equipment net addition (or removal) year over year - in urban areas	1.a.	Circuit miles of overhead transmission lines (including WUI and non-WUI)	0	0	0	0	0	0	0	0	0	0	0	0	Circuit miles	
		1.b.	Circuit miles of overhead distribution lines (including WUI and non-WUI)	0	0	0	0	0	0	0	0	0	0	-0.3	0	Circuit miles	
		1.c.	Circuit miles of overhead transmission lines in WUI	0	0	0	0	0	0	0	0	0	0	0	0	Circuit miles in WUI	
		1.d.	Circuit miles of overhead distribution lines in WUI	0	0	0	0	0	0	0	0	0	0	-0.3	0	Circuit miles in WUI	
		1.e.	Number of substations (including WUI and non-WUI)	0	0	0	0	0	0	-1	0	0	0	0	0	Number of substations	
		1.f.	Number of substations in WUI	0	0	0	0	0	0	-1	0	0	0	0	0	Number of substations in WUI	
		1.g.	Number of weather stations (including WUI and non-WUI)	0	0	1	0	0	0	0	0	0	0	0	0	Number of weather stations	
		1.h.	Number of weather stations in WUI	0	0	1	0	0	0	0	0	0	0	0	0	Number of weather stations in WUI	
x	2. Planned utility equipment net addition (or removal) year over year - in rural areas	2.a.	Circuit miles of overhead transmission lines (including WUI and non-WUI)	0	0	0	0	0	0	0	0	0	0	0	0	Circuit miles	
		2.b.	Circuit miles of overhead distribution lines (including WUI and non-WUI)	0	0	0	0	-0.1	0	-0.4	0	0	0	-0.35	0	Circuit miles	
		2.c.	Circuit miles of overhead transmission lines in WUI	0	0	0	0	0	0	0	0	0	0	0	0	Circuit miles in WUI	
		2.d.	Circuit miles of overhead distribution lines in WUI	0	0	0	0	-0.1	0	-0.4	0	0	0	0	0	Circuit miles in WUI	
		2.e.	Number of substations (including WUI and non-WUI)	0	0	0	0	0	0	0	0	0	0	-1	0	Number of substations	
		2.f.	Number of substations in WUI	0	0	0	0	0	0	0	0	0	0	0	0	Number of substations in WUI	
		2.g.	Number of weather stations (including WUI and non-WUI)	0	0	8	0	0	0	0	0	0	0	0	0	Number of weather stations	
		2.h.	Number of weather stations in WUI	0	0	8	0	0	0	0	0	0	0	0	0	Number of weather stations in WUI	
x	3. Planned utility equipment net addition (or removal) year over year - in highly rural areas	3.a.	Circuit miles of overhead transmission lines (including WUI and non-WUI)	0	0	0	0	0	0	0	0	0	0	0	0	Circuit miles	
		3.b.	Circuit miles of overhead distribution lines (including WUI and non-WUI)	0	0	0	0	0	0	0	0	0	0	0	0	Circuit miles	
		3.c.	Circuit miles of overhead transmission lines in WUI	0	0	0	0	0	0	0	0	0	0	0	0	Circuit miles in WUI	
		3.d.	Circuit miles of overhead distribution lines in WUI	0	0	0	0	0	0	0	0	0	0	0	0	Circuit miles in WUI	
		3.e.	Number of substations (including WUI and non-WUI)	0	0	0	0	0	0	0	0	0	0	0	0	Number of substations	
		3.f.	Number of substations in WUI	0	0	0	0	0	0	0	0	0	0	0	0	Number of substations in WUI	
		3.g.	Number of weather stations (including WUI and non-WUI)	2	0	8	0	0	0	0	0	0	0	0	0	Number of weather stations	
		3.h.	Number of weather stations in WUI	0	0	0	0	0	0	0	0	0	0	0	0	Number of weather stations in WUI	

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Notes:
Transmission lines refer to all lines at or above 65kV, and distribution lines refer to all lines below 65kV.
In future submissions update planned upgrade numbers with actuals
In the comments column on the far-right, enter the relevant program target(s) associated

Table 10: Location of actual and planned utility infrastructure upgrades year over year

				Actual								Projected					
				Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3	Non-HFTD	HFTD Zone 1	HFTD Tier 2	HFTD Tier 3		
	Metric type	**#**	**Outcome metric name**	**2020**	**2020**	**2020**	**2020**	**2021**	**2021**	**2021**	**2021**	**2022**	**2022**	**2022**	**2022**	**Unit(s)**	**Comments**
x	1. Planned utility infrastructure upgrades year over year - in urban areas	1.a.	Circuit miles of overhead transmission lines planned for upgrades (including WUI and non-WUI)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Circuit miles	
		1.b.	Circuit miles of overhead distribution lines planned for upgrades (including WUI and non-WUI)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	Circuit miles	
		1.c.	Circuit miles of overhead transmission lines planned for upgrades in WUI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Circuit miles in WUI	
		1.d.	Circuit miles of overhead distribution lines planned for upgrades in WUI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	Circuit miles in WUI	
		1.e.	Number of substations planned for upgrades (including WUI and non-WUI)	0	0	1	0	0	0	1	0	0	0	0	0	Number of substations	
		1.f.	Number of substations planned for upgrades in WUI	0	0	1	0	0	0	1	0	0	0	0	0	Number of substations in WUI	
		1.g.	Number of weather stations planned for upgrades (including WUI and non-WUI)	0	0	1	0	0	0	1	0	0	0	0	0	Number of weather stations	
		1.h.	Number of weather stations planned for upgrades in WUI	0	0	1	0	0	0	1	0	0	0	0	0	Number of weather stations in WUI	
x	2. Planned utility infrastructure upgrades year over year - in rural areas	2.a.	Circuit miles of overhead transmission lines planned for upgrades (including WUI and non-WUI)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	Circuit miles	
		2.b.	Circuit miles of overhead distribution lines planned for upgrades (including WUI and non-WUI)	0.0	0.0	3.6	0.0	0.0	0.0	3.6	0.0	0.0	0.0	7.4	6.5	Circuit miles	
		2.c.	Circuit miles of overhead transmission lines planned for upgrades in WUI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	Circuit miles in WUI	
		2.d.	Circuit miles of overhead distribution lines planned for upgrades in WUI	0.0	0.0	1.1	0.0	0.0	0.0	1.7	0.0	0.0	0.0	0.2	0.6	Circuit miles in WUI	
		2.e.	Number of substations planned for upgrades (including WUI and non-WUI)	0	0	0	0	0	0	2	1	1	0	0	0	Number of substations	
		2.f.	Number of substations planned for upgrades in WUI	0	0	0	0	0	0	2	1	1	0	0	0	Number of substations in WUI	
		2.g.	Number of weather stations planned for upgrades (including WUI and non-WUI)	0	0	0	0	0	0	2	1	1	0	0	0	Number of weather stations	
		2.h.	Number of weather stations planned for upgrades in WUI	0	0	0	0	0	0	2	1	1	0	0	0	Number of weather stations in WUI	
x	3. Planned utility infrastructure upgrades year over year - in highly rural areas	3.a.	Circuit miles of overhead transmission lines planned for upgrades (including WUI and non-WUI)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Circuit miles	
		3.b.	Circuit miles of overhead distribution lines planned for upgrades (including WUI and non-WUI)	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.0	Circuit miles	
		3.c.	Circuit miles of overhead transmission lines planned for upgrades in WUI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Circuit miles in WUI	
		3.d.	Circuit miles of overhead distribution lines planned for upgrades in WUI	0.0	0.0	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	Circuit miles in WUI	
		3.e.	Number of substations planned for upgrades (including WUI and non-WUI)	0	0	0	0	0	0	0	0	0	0	0	0	Number of substations	
		3.f.	Number of substations planned for upgrades in WUI	0	0	0	0	0	0	1	0	0	0	0	0	Number of substations in WUI	
		3.g.	Number of weather stations planned for upgrades (including WUI and non-WUI)	0	0	0	0	0	0	0	0	0	0	0	0	Number of weather stations	
		3.h.	Number of weather stations planned for upgrades in WUI	0	0	0	0	0	0	1	0	0	0	0	0	Number of weather stations in WUI	

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Notes:
"PSPS" = Public Safety Power Shutoff
In future submissions update planned upgrade numbers with actuals

Table 11: Recent use of PSPS and other PSPS metrics

Metric type	#	Outcome metric name	2015	2016	2017	2018	2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Q1 2023	Q2 2023	Q3 2023	Q4 2023	Unit(s)	Comments
			Actual														Projected								
1. Recent use of PSPS	1.a.	Frequency of PSPS events (total)	0	0	0	1	0	0	0	0	0	0	0	0	0	0								Number of instances where utility operating protocol requires de-energization of a circuit or portion thereof to reduce ignition probability, per year	
	1.b.	Scope of PSPS events (total)	0	0	0	3	0	0	0	0	0	0	0	0	0	0								Circuit-events, measured in number of events multiplied by number of circuits de-energized per year	
	1.c.	Duration of PSPS events (total)	0	0	0	90	0	0	0	0	0	0	0	0	0	0								Customer hours per year	
2. Customer hours of PSPS and other outages	2.a.	Customer hours of planned outages including PSPS (total)		5124	7025	31470	113282	29.8	16742.7	1521.9	31517.2	19409.86	2187	22928.83	67493	9578.2								Total customer hours of planned outages per year	
	2.b.	Customer hours of unplanned outages, not including PSPS (total)	112599	111988	133267	75720	246866	6294.2	10143	47305	84162.4	50977.49	8517	61661.16	248103	41609.15								Total customer hours of unplanned outages per year	
	2.c.	System Average Interruption Duration Index (SAIDI) (including PSPS)	357.53	213.63	1597.37	287.99	416.51	7.72	12.44	58.01	103.21	62.5171	10.18983	73.77058	297	49.78068								SAIDI index value = sum of all interruptions in time period where each interruption is defined as sum(duration of interruption * # of customer interruptions) / Total number of customers served	
	2.d.	System Average Interruption Duration Index (SAIDI) (excluding PSPS)	357.53	213.63	1597.37	287.99	416.51	7.72	12.44	58.01	103.21	62.5171	10.18983	73.77058	297	49.78068								SAIDI index value = sum of all interruptions in time period where each interruption is defined as sum(duration of interruption * # of customer interruptions) / Total number of customers served	
	2.e.	System Average Interruption Frequency Index (SAIFI) (including PSPS)	2.01	1.47	3.97	2.18	2.96	0.1212	0.078	1.0685	0.2887	0.3883	0.07238	0.547819	1	0.353051								SAIFI index value = sum of all interruptions in time period where each interruption is defined as (total # of customer interruptions) / (total # of customers served)	
	2.f.	System Average Interruption Frequency Index (SAIFI) (excluding PSPS)	2.01	1.47	3.97	2.18	2.96	0.1212	0.078	1.0685	0.2887	0.3883	0.07238	0.547819	1	0.353051								SAIFI index value = sum of all interruptions in time period where each interruption is defined as (total # of customer interruptions) / (total # of customers served)	
3. Critical infrastructure impacted by PSPS	3.a.	Critical infrastructure impacted by PSPS	0	0	0	0	0	0	0	0	0	0	0	0	0	0								Number of critical infrastructure (in accordance with D.19-05-042) locations impacted per hour multiplied by hours offline per year	
4. Community outreach of PSPS metrics	4.a.	# of customers impacted by PSPS	0	0	0	30	0	0	0	0	0	0	0	0	0	0								# of customers impacted by PSPS (if multiple PSPS events impact the same customer, count each event as a separate customer)	
	4.b.	# of medical baseline customers impacted by PSPS	0	0	0	0	0	0	0	0	0	0	0	0	0	0								# of customers impacted by PSPS (if multiple PSPS events impact the same customer, count each event as a separate customer)	
	4.c.	# of customers notified prior to initiation of PSPS event	0	0	0	0	0	0	0	0	0	0	0	0	0	0								# of customers notified of PSPS event prior to initiation (if multiple PSPS events impact the same customer, count each event in which customer was notified as a separate customer)	
	4.d.	# of medical baseline customers notified prior to initiation of PSPS event	0	0	0	0	0	0	0	0	0	0	0	0	0	0								# of customers notified of PSPS event prior to initiation (if multiple PSPS events impact the same customer, count each event in which customer was notified as a separate customer)	
	4.e.	% of customers notified prior to a PSPS event impacting them	0	0	0	0	0	0	0	0	0	0	0	0	0	0								=4.a. / 4.c.	
	4.f.	% of medical baseline customers notified prior to a PSPS event impacting them	0	0	0	0	0	0	0	0	0	0	0	0	0	0								=4.a. / 4.c.	
5. Other PSPS metrics	5.a.	Number of PSPS de-energizations	0	0	0	0	0	0	0	0	0	0	0	0	0	0								Number of de-energizations	
	5.b.	Number of customers located on de-energized circuit	0	0	0	185	0	0	0	0	0	0	0	0	0	0								Number of customers	
	5.c.	Customer hours of PSPS per RFW OH circuit mile day	0	0	0	0.03	0	0	0	0	0	0	0	0	0	0								=1.c. / RFW OH circuit mile days in time period	
	5.d.	Frequency of PSPS events (total) - High Wind Warning wind conditions	0	0	0	0	0	0	0	0	0	0	0	0	0	0								Events over time period that overlapped with a High Wind Warning as defined by the National Weather Service	
	5.e.	Scope of PSPS events (total) - High Wind Warning wind conditions	0	0	0	30	0	0	0	0	0	0	0	0	0	0								Estimated customers impacted over time period that overlapped with a High Wind Warning as defined by the National Weather Service	
	5.f.	Duration of PSPS events (total) - High Wind Warning wind conditions	0	0	0	90	0	0	0	0	0	0	0	0	0	0								Customer hours over time period that overlapped with a High Wind Warning as defined by the National Weather Service	

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Table No.	12
Date Modified	5/1/2022

Notes:
Risk-Spend-Efficiency (RSE) is defined as "An estimate of the cost-effectiveness of initiative, calculated by dividing the mitigation risk reduction benefit by the mitigation cost estimate based on the full set of risk reduction benefits estimated from the incurred costs."
CAPEX = Capital expenditure; OPEX = Operating expenditure.

Table 12: Mitigation initiative financials

Metric type	WMP Table # / Category	WMP Initiative #	Initative activity	Primary driver targeted	Secondary driver targeted	Year initiated	Estimated RSE territory-wide	Estimated RSE in non-HFTD region	Estimated RSE in HFTD Zone 1	Estimated RSE in HFTD Tier 2	Estimated RSE in HFTD Tier 3	If existing: most recent proceeding that has reviewed program	If new: memorandum account	Current compliance status - In / exceeding compliance with regulations	Associated rule(s) - if multiple, separate by semi-colon - ";"	If spend not disaggregated by category, note spend category or mark general	Comments	Actual 2020 CAPEX ($ thousands) Territory	Actual 2020 CAPEX ($ thousands) HFTD	Actual 2020 OPEX ($ thousands) Territory	Actual 2020 OPEX ($ thousands) HFTD	Actual 2020 Line miles treated Territory	Actual 2020 Line miles treated HFTD	Actual 2020 Alternative units (if used)	Actual 2021 CAPEX ($ thousands) Territory	Actual 2021 CAPEX ($ thousands) HFTD	Actual 2021 OPEX ($ thousands) Territory	Actual 2021 OPEX ($ thousands) HFTD	Actual 2021 Line miles treated Territory	Actual 2021 Line miles treated HFTD	Actual 2021 Alternative units (if used)	Projected 2022 CAPEX ($ thousands) Territory	Projected 2022 CAPEX ($ thousands) HFTD	Projected 2022 OPEX ($ thousands) Territory	Projected 2022 OPEX ($ thousands) HFTD	Projected 2022 Line miles to be treated Territory	Projected 2022 Line miles to be treated HFTD	Projected 2022 Alternative units (if used)	Projected 2023 CAPEX ($ thousands) Territory	Projected 2023 CAPEX ($ thousands) HFTD	Projected 2023 OPEX ($ thousands) Territory	Projected 2023 OPEX ($ thousands) HFTD	Projected 2023 Line miles to be treated Territory	Projected 2023 Line miles to be treated HFTD	Projected 2023 Alternative units (if used)
Other	Risk Assessment & Mapping	7.3.1.1.	A summarized risk map that shows the overall ignition probability and estimated wildfire consequence along the electric lines and equipment	Contact with vegetation	Equipment failure	2020	NA	NA	NA	NA	NA	2021 WMP	WMPMA	NA	NA	NA		-	-	67	67				-	-	53	53				-	-	55	55				-	-	10	10			
Other	Risk Assessment & Mapping	7.3.1.2.	Climate-driven risk map and modelling based on various relevant weather scenarios	PSPS - for sectionalization, etc.	Contact with vegetation	2020	NA	NA	NA	NA	NA	2021 WMP	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Risk Assessment & Mapping	7.3.1.3.	Ignition probability mapping showing the probability of ignition along the electric lines and equipment	Contact with vegetation	Other contact with object	2020	NA	NA	NA	NA	NA	2021 WMP	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Risk Assessment & Mapping	7.3.1.4.	Initiative mapping and estimation of wildfire and PSPS risk-reduction impact	PSPS - for sectionalization, etc.	Other contact with object	2021	NA	NA	NA	NA	NA	2021 WMP	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Risk Assessment & Mapping	7.3.1.5.	Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment	Other contact with object	Contact with vegetation	2020	NA	NA	NA	NA	NA	2021 WMP	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Situational Awareness & Forecasting	7.3.2.1.	Advanced weather monitoring and weather stations	PSPS - for sectionalization, etc.		2019	NA	NA	NA	NA	NA	2021 WMP	WFMMA	Exceeds	NA	NA		243	243	-	-			19	12	12	8	8				115	115	-	-			10	15	15	-	-			1
Other	Situational Awareness & Forecasting	7.3.2.2.	Continuous monitoring sensors	Equipment failure		2020	NA	NA	171.56	171.56	171.56	2021 WMP	WFMMA	NA	NA	NA		158	158	-	-				18	18	229	229				75	75	115	115			10	75	75	115	115			10
Other	Situational Awareness & Forecasting	7.3.2.3.	Fault indicators for detecting faults on electric lines and equipment	Equipment failure		2022	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-			2	-	-	-	-			
Other	Situational Awareness & Forecasting	7.3.2.4.	Forecast of a fire risk index, fire potential index, or similar	PSPS - for sectionalization, etc.		2020	NA	NA	NA	NA	NA	2021 WMP	WFMMA	Exceeds	NA	NA		-	-	44	44				-	-	14	14				-	-	10	10				-	-	10	10			
Other	Situational Awareness & Forecasting	7.3.2.5.	Personnel monitoring areas of electric lines and equipment in elevated fire risk conditions	Equipment failure	Other contact with object	2019	NA	NA	NA	NA	NA	2021 WMP	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Situational Awareness & Forecasting	7.3.2.6.	Weather forecasting and estimating impacts on electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.1.	Capacitor maintenance and replacement program	Equipment failure		2011	NA	NA	NA	NA	NA	NA	NA	In compliance	GO 165	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.2.	Circuit breaker maintenance and installation to de-energize lines upon detecting a fault	Equipment failure		TBD	NA	NA	NA	NA	NA	NA	NA	Exceeds	NA	NA		-	-	-	-				88	88	-	-				400	400	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.3.	Covered conductor installation	Other contact with object	Equipment failure	2019	NA	NA	0.27	0.27	0.27	2021 WMP	NA	In compliance	NA	NA		7,820	7,820	-	-			6.82	10,550	10,550	-	-			3.75	14,915	14,915	-	-			9.55	17,204	17,204	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.4.	Covered conductor maintenance			TBD	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.5.	Crossarm maintenance, repair, and replacement	Equipment failure		2020	NA	NA	NA	NA	NA	2021 WMP	NA	In compliance	GO 95; GO165	NA		89	89	5	5				-	-	-	-				-	-	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.6.	Distribution pole replacement and reinforcement, including with composite poles	Equipment failure		2011	NA	NA	NA	NA	NA	2021 WMP	NA	In compliance	GO 165	NA		3,652	3,652	-	-			62	5,003	5,003	-	-			211	6,000	6,000	-	-			231	1,250	1,250	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.7.	Expulsion fuse replacement	Equipment failure		2011	NA	2.29	2.29	2.29	2.29	2021 WMP	NA	In compliance	GO 165	NA		738	738	-	-			853	600	600	-	-			867	1,500	1,500	-	-			1,500	1,000	1,000	-	-			1500
Grid hardening	Grid Design & System Hardening	7.3.3.8.	Grid topology improvements to mitigate or reduce PSPS events	PSPS - for sectionalization, etc.		2020	NA	NA	NA	NA	NA	2021 WMP	NA	In compliance	R20A	NA		672	672	-	-				107	107	38	38				-	-	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.9.	Installation of system automation equipment	PSPS - for sectionalization, etc.		2011	NA	NA	NA	NA	NA	2021 WMP	NA	Exceeds	NA	NA		454	454	-	-			4	339	339	-	-			2	360	360	-	-			4	360	360	-	-			4
Grid hardening	Grid Design & System Hardening	7.3.3.10.	Maintenance, repair, and replacement of connectors, including hotline clamps			2011	NA	NA	NA	NA	NA	NA	NA	In compliance	GO 174	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.11.	Mitigation of impact on customers and other residents affected during PSPS event			NA	NA	NA	NA	NA	NA	NA	NA	Exceeds	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.12.	Other corrective action	Equipment failure	Contact with vegetation	2020	NA	NA	NA	NA	NA	2021 WMP	NA	NA	NA	NA		1,358	1,358	15	15				1,952	1,952	64	64			37	2,536	2,536	-	-			60	2,251	2,251	-	-			60
Grid hardening	Grid Design & System Hardening	7.3.3.13.	Pole loading infrastructure hardening and replacement program based on pole loading assessment program	Equipment failure		2011	NA	0.8	0.8	0.8	0.8	2021 WMP	NA	In compliance	GO 165	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.14.	Transformers maintenance and replacement			2011	NA	NA	NA	NA	NA	NA	NA	In compliance	GO 95; GO 165	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.15.	Transmission tower maintenance and replacement			2019	NA	NA	NA	NA	NA	NA	NA	Exceeds	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.16.	Undergrounding of electric lines and/or equipment	Other contact with object	Equipment failure		NA	0.44	0.44	0.44	0.44	2020 WMP	NA	Exceeds	NA	NA		522	522	-	-				903	903	-	-			1.03	7,000	7,000	-	-			0.36	3,900	3,900	-	-			
Grid hardening	Grid Design & System Hardening	7.3.3.17.	Updates to grid topology to minimize risk of ignition in HFTDs			NA	NA	NA	NA	NA	NA	NA	NA	Exceeds	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Asset inspection	Asset Management & Inspections	7.3.4.1.	Detailed inspections of distribution electric lines and equipment	Equipment failure	Other contact with object	2011	NA	NA	NA	NA	NA	2019 GRC	NA	In Compliance	GO95; GO128; GO165	NA		-	-	838	838			100%	-	-	409	409			20	-	-	400	400			308	-	-	400	400			
Asset inspection	Asset Management & Inspections	7.3.4.2.	Detailed inspections of transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	GO95; GO128; GO165	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Asset inspection	Asset Management & Inspections	7.3.4.3.	Improvement of inspections	Equipment failure	Other contact with object	2020	NA	NA	NA	NA	NA	2021 WMP	NA	In Compliance	GO95; GO128; GO165	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Asset inspection	Asset Management & Inspections	7.3.4.4.	Infrared inspections of distribution electric lines and equipment	Equipment failure	Other contact with object	2021	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	200	200			
Asset inspection	Asset Management & Inspections	7.3.4.5.	Infrared inspections of transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Asset inspection	Asset Management & Inspections	7.3.4.6.	Intrusive pole inspections	Equipment failure	Other contact with object	2011	NA	NA	NA	NA	NA	2019 GRC	NA	In Compliance	GO95; GO165	NA		-	-	10	10			2,577	-	-	158	158			3,506	-	-	150	150			2,598	-	-	150	150			
Asset inspection	Asset Management & Inspections	7.3.4.7.	LiDAR inspections of distribution electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Asset inspection	Asset Management & Inspections	7.3.4.8.	LiDAR inspections of transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Asset inspection	Asset Management & Inspections	7.3.4.9.	Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations	Equipment failure	Other contact with object	2020	NA	NA	NA	NA	NA	2021 WMP	NA	Exceeds	GO95; GO128; GO165	NA		-	-	-	-				20	20	1,056	1,056				-	-	4,600	4,600				-	-	4,600	4,600			
Asset inspection	Asset Management & Inspections	7.3.4.10.	Other discretionary inspection of transmission electric lines and	Equipment failure	Other contact with object	2020	NA	NA	NA	NA	NA	NA	NA	Exceeds	GO95; GO128; GO165	NA		2,994	2,994	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Asset inspection	Asset Management & Inspections	7.3.4.11.	Patrol inspections of distribution electric lines and equipment	Equipment failure	Other contact with object	2011	NA	NA	NA	NA	NA	2019 GRC	NA	In Compliance	GO95; GO165	NA		-	-	-	-				-	-	-	-			2,500	-	-	60	60			70	-	-	60	60			
Asset inspection	Asset Management & Inspections	7.3.4.12.	Patrol inspections of transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	In Compliance	GO95; GO165	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Asset inspection	Asset Management & Inspections	7.3.4.13.	Pole loading assessment program to determine safety factor	Equipment failure	Other contact with object	2013	NA	NA	NA	NA	NA	2019 GRC	NA	In Compliance	GO95	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Asset inspection	Asset Management & Inspections	7.3.4.14.	Quality assurance / quality control of inspections	Equipment failure	Other contact with object	2021	NA	NA	NA	NA	NA	NA	NA	In Compliance	GO95; GO128; GO165	NA		-	-	-	-				-	-	-	-				-	-	30	30			0.50%	-	-	30	30			0.50%
Asset inspection	Asset Management & Inspections	7.3.4.15.	Substation inspections	Equipment failure	Other contact with object	2016	NA	NA	NA	NA	NA	2019 GRC	NA	In Compliance	GO174	NA		-	-	-	-			46	-	-	-	-			46	-	-	10	10			42	-	-	10	10			42
Vegetation management project	Vegetation Management & Inspections	7.3.5.1.	Additional efforts to manage community and environmental impacts	Contact with vegetation		2020	NA	NA	NA	NA	NA	2021 WMP	WMPMA	Exceeds	GO 95 Rule 35; PRC 4293	NA		-	-	771	771			14	317	317	333	333			3.4	-	-	754	754			9	-	-	776	776			9
Vegetation inspection	Vegetation Management & Inspections	7.3.5.2.	Detailed inspections and management practices for vegetation clearances around distribution electrical lines and equipment	Contact with vegetation		2011	NA	0.27	0.27	0.27	0.27	2019 GRC	NA	Exceeds	GO 95 Rule 35; PRC 4293	NA		-	-	556	556				-	-	701	701			178	-	-	715	715			221	-	-	737	737			221
Vegetation inspection	Vegetation Management & Inspections	7.3.5.3.	Detailed inspections and management practices for vegetation clearances around transmission electrical lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Vegetation management project	Vegetation Management & Inspections	7.3.5.4.	Emergency response vegetation management due to red flag warning or other urgent weather conditions			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Vegetation management project	Vegetation Management & Inspections	7.3.5.5.	Fuel management (including all wood management) and management of "slash" from vegetation management activities			2020	NA	NA	NA	NA	NA	2021 WMP	WMPMA	Exceeds	PRC 4292; PRC 4293	NA	Unit conversion from tons to acres in 2022	-	-	355	355			376	-	-	1,196	1,196			2,119	-	-	1,163	1,163			280	-	-	1,198	1,198			280
Vegetation inspection	Vegetation Management & Inspections	7.3.5.6.	Improvement of inspections			NA	NA	0.27	0.27	0.27	0.27	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Vegetation inspection	Vegetation Management & Inspections	7.3.5.7.	Remote sensing inspections of vegetation around distribution electric lines and equipment	Contact with vegetation		2020	NA	NA	NA	NA	NA	NA	WMPMA	Exceeds	GO 95 Rule 35; PRC 4293	NA		369	369	-	-			320	350	350	303	303			701	-	-	764	764			701	-	-	787	787			701
Vegetation inspection	Vegetation Management & Inspections	7.3.5.8.	Remote sensing inspections of vegetation around transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Vegetation inspection	Vegetation Management & Inspections	7.3.5.9.	Other discretionary inspections of vegetation around distribution electric lines and equipment	Contact with vegetation		2020	NA	NA	NA	NA	NA	2021 WMP	WMPMA	Exceeds	GO 95 Rule 35; PRC 4293	NA		-	-	85	85				-	-	2	2				-	-	-	-				-	-	-	-			
Vegetation inspection	Vegetation Management & Inspections	7.3.5.10.	Other discretionary inspections of vegetation around transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Vegetation inspection	Vegetation Management & Inspections	7.3.5.11.	Patrol inspections of vegetation around distribution electric lines and equipment	Contact with vegetation		2018	NA	NA	NA	NA	NA	2019 GRC	NA	NA	NA	NA		-	-	421	421				-	-	338	338			179	-	-	357	357			167	-	-	368	368			167
Vegetation inspection	Vegetation Management & Inspections	7.3.5.12.	Patrol inspections of vegetation around transmission electric lines and equipment			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Vegetation inspection	Vegetation Management & Inspections	7.3.5.13.	Quality assurance / quality control of vegetation management	Contact with vegetation		2020	NA	NA	NA	NA	NA	2021 WMP	WMPMA	NA	NA	NA		-	-	67	67				-	-	141	141			155	-	-	418	418			220	-	-	430	430			220
Vegetation management project	Vegetation Management & Inspections	7.3.5.14.	Recruiting and training of vegetation management personnel			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Vegetation management project	Vegetation Management & Inspections	7.3.5.15.	Identification and remediation of "at-risk species"	Contact with vegetation		2011	NA	NA	NA	NA	NA	2019 GRC	NA	Exceeds	GO 95 Rule 35; PRC 4293	NA		-	-	7,338	7,338				-	-	4,678	4,678			238	-	-	5,704	5,704			238	-	-	5,875	5,875			238
Vegetation management project	Vegetation Management & Inspections	7.3.5.16.	Removal and remediation of trees with strike potential to electric lines and equipment	Contact with vegetation		2018	NA	NA	NA	NA	NA	2019 GRC	NA	Exceeds	GO 95 Rule 35; PRC 4293	NA		-	-	2,723	2,723				-	-	1,222	1,222			128	-	-	2,709	2,709			127	-	-	2,790	2,790			127
Vegetation inspection	Vegetation Management & Inspections	7.3.5.17.	Substation inspection			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Vegetation management project	Vegetation Management & Inspections	7.3.5.18.	Substation vegetation management			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Vegetation management project	Vegetation Management & Inspections	7.3.5.19.	Vegetation management enterprise system				NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Vegetation management project	Vegetation Management & Inspections	7.3.5.20	Vegetation management to achieve clearances around electric lines and equipment	Contact with vegetation		2011	NA	NA	NA	NA	NA	2019 GRC	NA	Exceeds	GO 95 Rule 35; PRC 4293	NA		-	-	-	-				-	-	985	985			361	-	-	1,493	1,493			701	-	-	1,538	1,538			701
Vegetation management project	Vegetation Management & Inspections	7.3.5.21	Vegetation management activities post-fire			2021	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Grid Operations & Operating Protocols	7.3.6.1.	Automatic recloser operations	Contact with vegetation	Equipment failure	2011	NA	NA	NA	NA	NA	NA	WMPMA	In compliance	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Grid Operations & Operating Protocols	7.3.6.2.	Protective equipment and device settings	PSPS - for sectionalization, etc.		2021	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Grid Operations & Operating Protocols	7.3.6.3.	Crew-accompanying ignition prevention and suppression resources and services			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Grid Operations & Operating Protocols	7.3.6.4.	Personnel work procedures and training in conditions of elevated fire risk	Equipment failure	Other contact with object	2019	NA	NA	NA	NA	NA	2021 WMP	WMPMA	In compliance	NA	NA		-	-	279	279				-	-	250	250				-	-	250	250				-	-	250	250			
Other	Grid Operations & Operating Protocols	7.3.6.5.	Protocols for PSPS re-energization	PSPS - for sectionalization, etc.		2020	NA	NA	NA	NA	NA	GO 166	WMPMA	In compliance	GO 166	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Grid Operations & Operating Protocols	7.3.6.6.	PSPS events and mitigation of PSPS impacts	PSPS - for sectionalization, etc.		2021	NA	NA	NA	NA	NA	NA	NA	In compliance	NA	NA		-	-	-	-				-	-	101	101				-	-	100	100				-	-	100	100			
Other	Grid Operations & Operating Protocols	7.3.6.7	Stationed and on-call ignition prevention and suppression resources and services				NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		93	93	-	-				46	46	-	-				100	100	-	-				100	100	-	-			
Other	Data Governance	7.3.7.1.	Centralized repository for data			2020	NA	NA	NA	NA	NA	2021 WMP	WMPMA	In compliance	NA	NA		-	-	-	-				10	10	-	-				-	-	400	400				-	-	100	100			
Other	Data Governance	7.3.7.2.	Collaborative research on utility ignition and/or wildfire	Contact with vegetation		2021	NA	NA	NA	NA	NA	2021 WMP	WMPMA	In compliance	NA	NA		-	-	1	1				-	-	101	101				120	120	-	-				120	120	-	-			
Other	Data Governance	7.3.7.3.	Documentation and disclosure of wildfire-related data and algorithms			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Data Governance	7.3.7.4.	Tracking and analysis of near miss data			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Resource Allocation Methodology	7.3.8.1.	Allocation methodology development and application			2020	NA	NA	NA	NA	NA	2021 WMP	WMPMA	In compliance	NA	NA		-	-	-	-				-	-	311	311				-	-	300	300				-	-	300	300			
Other	Resource Allocation Methodology	7.3.8.2.	Risk reduction scenario development and analysis			NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Resource Allocation Methodology	7.3.8.3.	Risk spend efficiency analysis			2020	NA	NA	NA	NA	NA	2021 WMP	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Emergency Planning & Preparedness	7.3.9.1.	Adequate and trained workforce for service restoration	PSPS - for sectionalization, etc.		2011	NA	NA	NA	NA	NA	2021 WMP	WMPMA	In compliance	NA	NA		-	-	502	502				-	-	460	460				-	-	1,304	1,304				-	-	1,304	1,304			
Other	Emergency Planning & Preparedness	7.3.9.2.	Community outreach, public awareness, and communications efforts			2011	NA	NA	NA	NA	NA	2021 WMP	WMPMA	Exceeds	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Emergency Planning & Preparedness	7.3.9.3	Customer support in emergencies			2011	NA	NA	NA	NA	NA	2021 WMP	WMPMA	In compliance	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Emergency Planning & Preparedness	7.3.9.4.	Disaster and emergency preparedness plan			2011	NA	NA	NA	NA	NA	GO 166	NA	In compliance	GO 166	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Emergency Planning & Preparedness	7.3.9.5.	Preparedness and planning for service restoration	PSPS - for sectionalization, etc.	Equipment failure	2011	NA	NA	NA	NA	NA	GO 166	NA	In compliance	GO 166	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Emergency Planning & Preparedness	7.3.9.6.	Protocols in place to learn from wildfire events			2011	NA	NA	NA	NA	NA	GO 166	NA	In compliance	GO 166	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Stakeholder Cooperation & Community Engagement	7.3.10.1	Community engagement			2019	NA	NA	NA	NA	NA	2021 WMP	WMPMA	Exceeds	P.U. Code § 451	NA		-	-	92	92				-	-	102	102				-	-	144	144				-	-	94	94			
Other	Stakeholder Cooperation & Community Engagement	7.3.10.2	Cooperation and best practice sharing with agencies outside CA			2011	NA	NA	NA	NA	NA	2021 WMP	WMPMA	In compliance	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Stakeholder Cooperation & Community Engagement	7.3.10.3	Cooperation with suppression agencies			NA	NA	NA	NA	NA	NA	2021 WMP	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			
Other	Stakeholder Cooperation & Community Engagement	7.3.10.4	Forest service and fuel reduction cooperation and joint roadmap			NA	NA	NA	NA	NA	NA	2021 WMP	NA	NA	NA	NA		-	-	-	-				-	-	-	-				-	-	-	-				-	-	-	-			

Attachment B

Liberty Resiliency Portfolio Final Report

September 28, 2021

Resiliency Portfolio Design

Liberty CalPeco

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About TRC

TRC is a global consulting and engineering firm providing services to energy, environment, and infrastructure industries for more than 50 years. TRC's nearly 6,000 professionals across 150 offices serve a broad range of public and private clients, guiding complex projects from conception to completion to help solve the toughest challenges in our built environment.

TRC was selected to develop this report based on the company's decades of experience designing, implementing, and managing energy programs in California and across the U.S. on behalf of utilities, state agencies, and community choice aggregators. TRC is a thought leader in the emerging arena of energy resiliency, developing programs and projects that provide important customer and community resiliency benefits. Additionally, TRC has broader consultative and technological perspective on utility grid transformation, through distributed energy resources management systems, data analytics, IT/OT integration and grid modernization, based on their half-century of work with power systems. Together, TRC's knowledge and experience provides insights to support Liberty objectives.

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1 Executive Summary

In February of 2020, Liberty Utilities (CalPeco Electric) LLC ("Liberty") filed a Wildfire Mitigation Plan with the California Public Utilities Commission (CPUC) that focused on efforts to address grid reliability and resiliency, given the increased risk of wildfires in the region. Then, in March of 2021, as part of its Wildfire Mitigation Plan update, Liberty submitted a *Customer Resiliency Program Design Concept,* providing initial thoughts on new offerings that Liberty would like to provide to customers for greater energy resiliency during future hazardous events.

Liberty builds on its initial *Design Concept* through this report, providing a comprehensive Resiliency Portfolio (Portfolio) Design to support a Portfolio application to the CPUC. The proposed Liberty Portfolio detailed in this report provides customer energy resiliency benefits through Liberty ownership, installation, operation, and maintenance of resiliency service assets in two phases:

- **Portfolio Phase 1**: The first phase of the Portfolio includes a three-year proposal wherein Liberty seeks to develop and deliver: 1) a Customer Resiliency Program, providing behind-the-meter (BTM) energy storage systems and resiliency services to medical baseline, critical facilities, and large commercial customers, and 2) a microgrid demonstration project, including grid-side equipment enhancements to Liberty's ongoing resiliency investments at Kings Beach. A conceptual design, budgetary estimate, and benefit-cost analysis is included in this proposal for CPUC consideration.
- **Portfolio Phase 2:** The second phase will follow the first three years of the Portfolio, building from lessons and insights gleaned through Phase 1 and allowing Liberty to monitor outage data, and will include the development of high-priority, geographically targeted resiliency corridors through a Resiliency Corridor Program. This Phase 2 concept does not include a conceptual design, budgetary estimate design, or benefit-cost analysis at this time, because these elements will be developed in the future and informed by Phase 1.

Figure 1. Liberty Proposed Resiliency Portfolio

Liberty will own, operate, and maintain the Portfolio resiliency assets and services. The Portfolio is intended to serve Liberty customers in anticipation of increasing hazardous events across Liberty's territory, including wildfire, public safety power shut-off (PSPS), and winter storm events. By providing essential energy resiliency benefits to customers, the Portfolio will improve the reliability and resilience of Liberty electric service and safety for customers, support ongoing community operations and economic development, ease customers' burden in securing resiliency technologies, and contribute to Liberty's ongoing priorities for safe and cost-effective maximization of clean energy.

As the foundation of the Portfolio, Phase 1 will deliver a total potential of 55 MWh of energy storage available to support resiliency for up to 173 customers through the Customer Resiliency Program (Program). The Program is proposed to run for three years, during which time participating customers will enroll and receive installed Battery Energy Storage Systems (BESS) in their homes, businesses, and facilities. Participating customers will make Resiliency-as-a-Service (RaaS) payments that will be added to their bills over the 10-year life of the BESS asset, during which time customers will receive benefits and Liberty will own, manage, and maintain the systems.

The RaaS model defers and distributes over time the upfront capital and ongoing operational costs to customers. RaaS payments and offerings have also been designed to meet the needs and limitations of each eligible customer type, including highly subsidized offerings for medical baseline customers. Critical facilities and large commercial customers RaaS payments will reflect the BESS sized for their individual needs.

Liberty procures most of its energy through a long-term Energy Services Agreement with NV Energy. Liberty can reduce its procurement cost by minimizing the monthly peak demand across its customer base. While customer resiliency benefits are Liberty's primary motivation for the Program, Liberty may also deliver financial benefits to all customers through demand savings in the NV Energy contract.

Additionally, in Phase 1, Liberty proposes a Kings Beach microgrid resiliency corridor demonstration project, which will add select grid-side equipment to an already secured 12 MW of generation to support resiliency needs from existing Liberty diesel generators. Customers in the Kings Beach community will directly benefit from the microgrid, as the diesel back-up power is applied to provide electric service to residents, businesses, and facilities. Portfolio Phase 2 will deliver similar quantifiable societal resiliency benefits in the future, as additional targeted geographic resiliency corridors are developed.

Liberty performed a benefit-cost analysis to assess the financial viability of the proposed Portfolio Phase 1. The analysis accounted for the equipment, operations and maintenance, and Program administration costs, and it estimated both financial benefits from avoided bulk energy contract costs and customer RaaS payments. The overall Portfolio benefit-cost ratio is 1.35, without factoring in the societal resiliency benefits shared among participating customers and the local community.

Liberty proposes that its Portfolio be delivered through a phased approach, with distinct offerings and benefits for each customer segment and/or geographic area. This approach aims to meet unique customer and community needs with the best and most appropriate solutions. It also builds flexibility into the Portfolio design, enabling Liberty to incorporate learnings and evolve the Portfolio efficiently over time.

2 Portfolio Development Process

Liberty has undertaken rigorous efforts to develop a Portfolio that will meet the resiliency needs of its customers, provide important community benefits, deliver a strong return on investment, and be well-received by relevant stakeholders. The following outlines Liberty's process to conceptualize and prepare the complete Portfolio design detailed within this report.

1 RESILIENCY NEED IDENTIFICATION

Liberty identified the need for customer resiliency offerings, driven by wildfire, PSPS, and winter storm outage events. Liberty conducted a Stakeholder Engagement Survey #1 in 2020 to assess general customer interest and limitations around energy storage as a possible resiliency solution. Customers responded favorably, and Liberty initiated the process to develop a Resiliency Portfolio.

2 INDUSTRY REVIEW

To inform its Portfolio, Liberty reviewed resiliency program and project models considered and implemented by U.S. utilities. Liberty identified well-founded models to incorporate within its own design considerations, including the Pacific Gas & Electric Company's (PG&E) Community Microgrid Enablement Program, which has been approved by the CPUC and the Northern States Power's (Xcel Energy's) Resiliency Service Pilot, approved by the Wisconsin Public Service Commission.

3 INITIAL PORTFOLIO DESIGN CONCEPT

Liberty developed a high-level Portfolio design concept, identifying target customers, outage durations to be addressed, and potential delivery models and value streams.

4 WILDFIRE MITIGATION PLAN UPDATE

Liberty included the Portfolio design concept as an appendix to its 2021 Wildfire Mitigation Plan update, identifying that a comprehensive Portfolio application would follow. The initial design concept highlighted Portfolio benefits during outage as well as blue sky conditions.

5 RESILIENCY NEEDS ASSESSMENT

Liberty developed a framework to assess resiliency needs in its territory and applied this framework to identify regional corridors with the highest resiliency benefits. Liberty considered hazards, disruption challenges, penetration of critical customers, and social impacts in various regions of its service territory. Liberty identified the Kings Beach region as an initial target for resiliency services, with other regions to be considered for future development.

6 PORTFOLIO DESIGN

Liberty developed a comprehensive Portfolio design, detailed within this report, providing a two-phased approach for Liberty customer resiliency offerings. This includes a conceptual design, budgetary estimate, and benefit-cost analysis for Portfolio Phase 1 and an initial concept for Phase 2.

7 **STAKEHOLDER ENGAGEMENT**

Liberty identified key stakeholders in its service territory likely to participate in or be affected by the Portfolio. Liberty built upon its previous Stakeholder Engagement Survey #1 by administering a Stakeholder Engagement Survey #2 to gather additional feedback, specific to the Portfolio as currently designed. Liberty also conducted a Community Info Session webinar, presenting the Portfolio to critical facilities and large commercial customers. Customer feedback was taken into consideration as Liberty finalized the Portfolio design and prepared this report.

8 **PORTFOLIO APPLICATION FILING**

Liberty developed this report to accompany its Portfolio application for CPUC for approval.

2.1 Stakeholder Engagement

Liberty appreciates the importance of securing customer feedback on and support for resiliency offerings like the Portfolio to offer fully realized benefits. For this reason, Liberty incorporated a stakeholder engagement process within its Portfolio development efforts. Goals for engagement included:

- Educating target customers on the programmatic and technical considerations and benefits of resiliency programs and projects generally and back-up BESS specifically
- Soliciting constructive input to enhance the Portfolio design and increase the likelihood of customer participation
- Opening an ongoing line of communication with the community around the offerings

Within the Portfolio, the Phase 1 Customer Resiliency Program (Program) will rely on direct customer participation. Through stakeholder outreach, Liberty sought to assess customer and community interest in the Program and potential barriers to participation. Liberty collected input from residential and commercial customers through a Stakeholder Engagement Survey #1 in 2020 to assess customers interest in installing a back-up BESS. Based on positive interest across both customer types, Liberty launched a formal Program design process.

Towards the end of this process, Liberty conducted additional outreach and a Stakeholder Engagement Survey #2 to validate its prepared Program design. Liberty engaged customers and community members through channels most appropriate to their circumstances. Medical baseline customers received digital and direct-mail surveys to provide input. Critical facilities and large commercial customers were invited to a Community Info Session webinar hosted by Liberty and received follow-up digital surveys to provide input.

Customer responses collected through Stakeholder Engagement Surveys #1 and #2 were incorporated into the final Program design presented in this report. Liberty may conduct additional stakeholder engagement activities to prepare for Portfolio launch.

3 Resiliency Portfolio Overview

3.1 Goals and Objectives

Liberty defines energy resiliency as the ability to avoid, prepare for, minimize, adapt to, and recover from anticipated and unanticipated energy disruptions to provide energy availability and reliability. The energy availability will be sufficient to provide for critical load assurance and readiness, including Emergency Support Functions related to readiness, and to execute or rapidly reestablish critical lifeline essential requirements[1]. This definition was adopted by the Electric Power Research Institute's (EPRI) value of resiliency working group. In alignment with this definition, the Liberty Portfolio sets forth the following goal and objectives.

Goal: Deliver cost-effective Resiliency Portfolio offerings within Liberty's service territory to provide customers with reliable back-up power during wildfire, PSPS, and winter storm events.

Objectives: Liberty proposes to deliver a phased Resiliency Portfolio, including 1) Phase 1: BTM Customer Resiliency Program and Kings Beach microgrid resiliency corridor demonstration project, and 2) Phase 2: Resiliency Corridor Utility Program. Objectives for this Portfolio include:

- Deliver Phase 1 BTM Customer Resiliency Program to customers in 2023
- Begin Phase 1 construction and development of the Kings Beach microgrid resiliency corridor demonstration project during 2023
- Identify additional value streams associated with energy storage, beyond resiliency, that support the utility business case and provide stackable values to customers, Liberty, and communities
- Investigate opportunities for Portfolio Phase 2, including the development of additional resiliency corridors throughout Liberty's territory

Liberty understands that resiliency is the primary Portfolio need for Liberty customers; however, other value streams could also be harnessed through the Portfolio during blue sky operations. Further details on this potential are provided in *Section 9.1.2*.

3.2 Portfolio Need and Benefits

Liberty proposes the Portfolio to address increasing hazardous events affecting customers across its territory, including wildfires, PSPS, and winter storm events. These events pose a real threat of impactful outages. Liberty's territory sits within a mountainous, heavily treed, high fire-threat area that experiences multiple hazards throughout the year. Wildfires, winter storms, and PSPS events are the main hazards expected to increase over the next ten years, growing more frequent and extreme.[2] Liberty's Portfolio is designed to address these three major hazards experienced by customers.

Since Liberty is a winter-peaking utility, it is important to address the impacts of increased winter storms. Additionally, while Liberty did not have any PSPS events in 2019 or 2020, one event did occur in 2018. In 2019, neighboring utility PG&E experienced multiple PSPS events causing outages ranging from

[1] EPRI. (2020, March). Value of Resilience Interest Group. https://www.epri.com/research/products/000000003002018412

[2] Michael Goss *et al* 2020 *Environ.* https://iopscience.iop.org/article/10.1088/1748-9326/ab83a7

3-16 days.[3] Considering the changing climate and projected shifts, Liberty is expecting PSPS events to become more frequent and necessary to protect its service territory from future wildfires; therefore, Liberty is taking a proactive approach in developing this Portfolio to provide resiliency for customers. The Portfolio is designed to support Liberty customer outages lasting up to 24 hours, although if customers use the energy storage systems more conservatively or in conjunction with photovoltaic (PV) solar systems, back-up power could last longer during prolonged outage events.

Through Portfolio Phase 1, Liberty identified specific customer types that are at highest risk across Liberty's territory—from a health, safety, and economic perspective—as the result of outages, including medical baseline, critical facilities, and large commercial customers. Liberty's proposed Portfolio specifically targets these customers through the Customer Resiliency Program. Liberty resiliency services for these customers will have particular value, given the vulnerable status of medical baseline customers and the ancillary community impacts resulting from loss of power among critical facilities and large commercial customers.

Additionally, Liberty identified Kings Beach as a high-risk region for impactful outages, given its populated location and economic center. For this geographic region, Liberty will develop the microgrid resiliency corridor demonstration project.

To deliver additional customer and community benefits, Portfolio Phase 2 will progressively build on the lessons and insights gleaned through Phase 1. While Liberty disruption metrics are comparable to other California utilities, Liberty will identify circuits that experience the most outages within the service territory and target these circuits and the most common causes of outages in its resilience planning. When investigating opportunities for resiliency corridors, the Liberty team is looking at instances when larger customer groups are offline, on a substation or circuit level. These locations are in most need of resiliency services and are prime target areas for Portfolio Phase 2.

Given potential hazards, Liberty's Portfolio will provide customers with important benefits:

- **Energy Resiliency**: Energy storage provides back-up power for customers during PSPS, winter storm, and other outage events.
- **Customer Experience:** While some customers might consider securing back-up power on their own, Liberty's Portfolio offerings provide a broader range of customers with affordable access to high-quality, reliable systems and expert technology providers. The Portfolio design also alleviates potentially prohibitive cost burdens to customers, including subsidizing offerings for medical baseline customers and deferring and distributing over time upfront and ongoing maintenance costs for all customers.
- **Public Safety**: Back-up power can support customers, especially during cold winter months, keeping medical equipment and critical facilities online and allowing for continued operation of emergency command centers and police facilities.
- **Business and Service Continuity**: Local government and commercial businesses can continue operations with back-up power, important for public benefit and local economic development.
- **Clean / Hybrid Energy**: While diesel generators are a common near-term solution for back-up power, leveraging BESS in combination with Liberty's clean generation sources as the foundation of the Portfolio enables Liberty to best contribute towards its multifaceted goals.

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[3] https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electrical_Infrastructure,_Planning,_and_Permitting/Reliability_and_Distribution_Infrastructure/Reliability/2019_PGE.pdf

3.3 Portfolio Offerings

Liberty proposes to deliver Resiliency Portfolio offerings to customers through a phased approach:

Phase 1: Customer Resiliency Program & Kings Beach Resiliency Corridor Demonstration Project	Phase 2: Resiliency Corridor Program
• Liberty-owned BTM battery storage systems for medical baseline, critical facilities, and large commercial customers • Liberty receives monthly RaaS payment from customers • Kings Beach acts as resiliency corridor demonstration project, exploring the value of and need for additional Resiliency Corridor investments in Phase 2	• Liberty is responsible for certain grid-side investments required for the optimization and effective operations of resiliency corridors in the event of a larger system outage • All or portions of resiliency corridors can be initiated by collections of community members (community microgrid) or by Liberty as an extension of its grid hardening investments

Table 1. Portfolio Phased Approach

Phase 1 Offerings

Through Phase 1, Liberty will deliver a Customer Resiliency Program (Program) that provides Liberty-owned, BTM BESS to medical baseline, critical facilities, and large commercial customers across its service territory. Liberty will own, maintain, and operate the storage assets, providing RaaS or back-up power benefits to participating customers during outage events. Most customers who opt to secure this service will provide a monthly RaaS payment, that will be added to their bill.

The Program is proposed to run for three years, during which time participating customers will be enrolled and will receive the installed BESS. Liberty will then own and maintain the systems over the asset life of 10 years, while customers make RaaS payments and gain benefits over this term. This Program design defers and distributes over time upfront capital costs to customers, which is often a barrier to their participation, as well as ongoing operations and maintenance costs. This Program may also deliver financial benefits to all customers through demand savings in the NV Energy contract.

Program RaaS payments and offerings are designed to meet the needs and limitations of each customer type. Medical baseline customers particularly require additional financial support to adopt BTM BESS, given these customers often face financial constraints and few other funding programs exist at federal, state, and local levels to easily offer this support. Liberty's proposed offering for medical baseline customers is highly subsidized, such that customers will pay a maximum of $10 per month and those on CARE rates will pay nothing. This approach provides affordable resiliency value to a vulnerable population, allowing medical baseline customers that want backup power through a BESS to receive it.

Critical facility and large customers will also benefit from the Program, with monthly payments and no upfront system costs and a simplified process to evaluate BESS options and select, size, install, and maintain the asset. RaaS payments made by these customer types cover system and maintenance costs. The payments are unsubsidized and will vary based on the load requirement and size of the BESS. Large commercial customers will also receive technical assistance to encourage participation, strengthening the Program benefit-cost ratios.

	Medical Baseline Customers	Critical Facilities Customers	Large Commercial Customers
Ownership	Liberty-owned BESS		
Objective	Provide resiliency services to customers to allow medical equipment to remain operational during outage events.	Provide resiliency services to critical public facilities that support customer health and safety during outage events.	Provide conditional technical assistance to large customers to investigate BTM storage and microgrid potential; provide resiliency services to customers who opt in.
Eligibility	Residential customers that participate in the Liberty Green Cross program, including those with proof of medical equipment needs from a physician.	CPUC Decision 19-05-042 definition of critical facilities, expanded to include customers with gas station, grocery store, and diesel fuel supply facilities.	Large commercial customers on qualified A3 rates.
Offerings	• Customers make a highly subsidized RaaS payments to Liberty to receive adequate back-up power for medical equipment • Medical baseline customers on CARE rates receive services for free, paying no RaaS fee • Liberty owns the BTM systems and customer RaaS payments help cover the cost of equipment and maintenance over ten years	• Customers make an unsubsidized RaaS payments to receive adequate back-up power is available to cover critical loads during outage events up to 24 hours • Liberty owns the BTM systems and customer RaaS payments cover the cost of equipment and maintenance over ten years	• Technical assistance is assigned as a credit to large customers, if after the technical and financial feasibility of a project is deemed viable, the customer elects to proceed with the project through the Liberty Program • If customer opts to proceed with a Liberty-owned project, unsubsidized RaaS payments will be assigned to their monthly bill to receive adequate back-up power • Liberty owns the BTM systems and customer RaaS payments cover the cost of equipment and maintenance over ten years

	Medical Baseline Customers	Critical Facilities Customers	Large Commercial Customers
Program Target & Incentives	• Target Customers[4]: ~117 • Total RaaS payment for medical baseline customers on CARE rates[5]: $0/month • Total RaaS payment for medical baseline customers on other rates: ~$10/month	• Target Customers[6]: ~35 • Total RaaS payment: ~$4,000/month[7]	• Target Customers: ~21 • Total RaaS payment: ~$4,000/month • Technical assistance: Up to $15,000/study

Table 2. Summary of Customer Resiliency Program

Additionally, within Phase 1, Liberty will develop a Kings Beach microgrid project that helps realize the resiliency value of existing local generation assets and demonstrates the value of geographic resiliency corridors within Liberty's service territory. Liberty intends to add select grid-side microgrid technologies to optimize 12MW of diesel generation assets, thereby providing maximum resiliency to residential and commercial customers within the designated circuit areas.

The proposed microgrid demonstration project will enable Liberty's diesel generators to pick up load within the microgrid area when normal grid supply is not available. With minor investments, this project will extend the benefits of Liberty's existing investments and provide electric service to the Kings Beach community during outages. Liberty proposes to begin construction on this project within the first three years of the Portfolio. Ultimately, the project will serve as an operational and benefits demonstration as well as precedent for future Liberty resiliency corridor investments.

Phase 2 Offerings

Liberty's Phase 2 Resiliency Corridor Program will build on insights and successes from the Phase 1 Kings Beach project to invest in additional geographically targeted resiliency corridors. Liberty will identify at-risk areas of the grid, where either community assets and/or Liberty grid hardening and capital projects could be leveraged, to make additional microgrid investments. These additional utility-owned, front-of-the-meter asset investments will facilitate optimal operations of the corridors in the event of a larger system outage. The exact nature of the Phase 2 Program will be determined after Phase 1.

[4] Liberty assumes 40% of total Liberty medical baseline customers will participate in the Program.

[5] Liberty estimates 50% of participating medical baseline customers will be on CARE rates and make no RaaS payment.

[6] Liberty assumes 40% of total critical facilities and large commercial customers will participate in the Program.

[7] The monthly RaaS payment of $4,000 per month, for critical facilities and large commercial customers, is an approximation based on an estimated energy storage system sized for facilities with an average daily load of 2,800 kWh and peak load of 1 MW. Actual RaaS payments will reflect the system size, specific to each customer.

Portfolio Term

Liberty proposes to deliver the Portfolio on the following timeline.

October 2021	**PORTFOLIO APPLICATION FILED WITH CPUC** Application developed and submitted to the CPUC, including Resiliency Portfolio offerings, benefit-cost analysis, budget, and implementation plan.
2022	**(PENDING) CPUC APPROVAL & LIBERTY IMPLEMENTATION** Upon approval by the CPUC, Liberty will prepare to implement the Phase 1 Customer Resiliency Program (Program) and Kings Beach microgrid demonstration project.
2023	**PROGRAM LAUNCH** Liberty expects to launch the Program in early 2023. Through the first year, Liberty will monitor progress and make any adjustments or incorporate innovations prior to Year 2.
2023 - 2025	**PORTFOLIO PHASE 1** Liberty proposes to implement the Program for 3 years, with annual evaluations and reporting to continually improve upon it over time. Liberty will also expect to begin construction of the Kings Beach project during this time.
2025 & Beyond	**PORTFOLIO PHASE 2** Liberty will leverage lessons and insights gleaned through Phase 1 towards design and implementation of a Phase 2 Resiliency Corridor Program, including the development of additional resiliency corridors across other areas within Liberty's territory.

4 Portfolio Phase 1: Customer Resiliency Program and Kings Beach Resiliency Corridor Demonstration Project

Portfolio Phase 1 will provide energy resiliency to Liberty customers across its service territory, through a 1) Customer Resiliency Program (Program), offering BTM BESS to eligible customers, and 2) a microgrid demonstration project in the Kings Beach region, leveraging existing utility diesel generation assets and the addition of equipment for microgrid islanding enablement. Together, these offerings will provide customers with back-up power during outage events, while also aligning with Liberty's long-term goals around grid modernization and safe and cost-effective maximization of clean energy.

4.1 Customer Resiliency Program

4.1.1 Customers Served

The Program will serve three customer types across Liberty's service territory, targeting resiliency benefits towards vulnerable populations and customers who contribute towards community benefits. Additional eligibility criteria and considerations for project prioritization will be defined for each through the Program design phase as described in *Section 6*.

Medical Baseline Customers

Residential customers that participate in the Liberty Green Cross program, including those with proof of medical equipment needs provided by a physician, will be eligible for the Program. Liberty assumes that 40% of Liberty's medical baseline customers will participate in the Program; refer to *Appendix B* for further information on this assumption.

This participation level takes into consideration Liberty's understanding that approximately half of medical baseline customers own their homes (vs. rent). Additionally, it considers that some renting customers, such as short-term renters or those unable to get a landlord's permission to install a BESS, may not be able to participate in the Program under its current design.

Critical Facility Customers

Liberty customers considered critical facilities customers will be eligible for the Program. Liberty will use the CPUC list of critical facilities and infrastructure[8] as the basis for its critical facilities definition. This includes police and fire stations; emergency operations centers; medical facilities; public and private utility facilities; water treatment and management facilities; communication carrier infrastructure; and jails and prisons.

Additionally, Liberty expands its critical facilities definition and Program eligibility to include customers with gas station, grocery store, and diesel fuel supply facilities. These customers supply essential goods and services—the loss of which could cause material human and economic harm to local communities.

[8] Decision 19-05-042. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M296/K598/296598822.PDF

Liberty assumes that 40% of Liberty customers with critical facilities will participate in the Program; refer to *Appendix B* for further information on this assumption.

Large Commercial Customers

Large commercial customers participating in Liberty's A3 rate class will be eligible for the Program. Liberty assumes that 40% of Liberty customers with commercial facilities will participate in the Program; refer to *Appendix B* for further information on this assumption.

4.1.2 Offerings: Technologies and Technical Assistance

Technology

Technology Considered

In developing its Program, Liberty considered multiple technology types to meet its resiliency and business objectives. Liberty evaluated the relative merits and disadvantages of each.

Fossil-Fuel Generators: For decades, fossil-fueled generators have been the technology of choice for energy resiliency—from BTM residential systems to critical facilities, such as hospitals, wastewater treatment plants, military bases, and college campuses. This conventional approach has been successful due to the technology's relatively low initial cost, ability to operate while fuel supplies last, and maturity of the market and plentiful supply.

Fossil-fuel generators, however, come with disadvantages as well. They are dependent on fuel supply through delivery and onsite storage, which may not always be available. Additionally, generators are often oversized to account for peak loads, which results in inefficient part-load operation. They are also typically loud and noisy and release toxic emissions and greenhouse gasses to the vicinity. Finally, generators require routine testing and maintenance, which is often neglected and leads to high rates of failure. According to a 2020 NREL study[9], "A poorly maintained emergency diesel generators (EDG) is unlikely to provide power for durations longer than a few days and has a reliability of only 80% at 12 hours…even well maintained EDGs have a reliability of only 80% at two weeks."

Liberty expects diesel generation to be a necessary immediate-term solution and investment in some instances across its service territory. However, through this application, Liberty seeks to develop a Portfolio of resiliency services that provide clean, reliable electricity to its customers whenever possible.

Battery Storage, Solar PV, and Microgrids: More recently, interest and investment in innovative new technologies have resulted in a new direction for energy resiliency. Energy storage, often coupled with renewable generation technologies, offer significant benefits over the traditional backup generator. These technologies can be designed to cover both short- and long-duration outages and are not reliant on on-site fuel storage or delivery. They can also be optimally sized and dispatched by taking advantage of diverse, non-coincident peak loading.

Additionally, higher upfront cost can be offset by significant lifetime energy cost savings and otherwise unavailable revenue opportunities such as selling capacity, energy, and ancillary services to the grid, or by participating in demand response opportunities. Microgrids (technologies with islanding capabilities) offer extremely high reliability due to their ability to share generation, and "maintain a high probability of meeting 100% of the critical loads" according to the NREL study. Finally, battery operation is much

[9] https://www.nrel.gov/docs/fy20osti/76553.pdf

quieter and less disruptive than traditional generators, and if charged by renewable generation such as solar PV, does not produce any greenhouse gas emissions.

Given these benefits, Liberty proposes to leverage BESS technology, backed by renewable generation, as the foundation of the Portfolio. In doing so, Liberty contributes to its business continuity and renewable energy objectives, while paving the way for additional possible revenue streams in the future.

Technology Proposed

Liberty proposes to provide BTM BESS to customers participating in the Program. The BESS will store energy from the grid during normal grid operations and discharge the energy as back-up power to customers when the grid is not available, during an outage. While the detailed design of the proposed DERs will vary and are unique to each customer, a general configuration of a BTM islandable system is shown below.

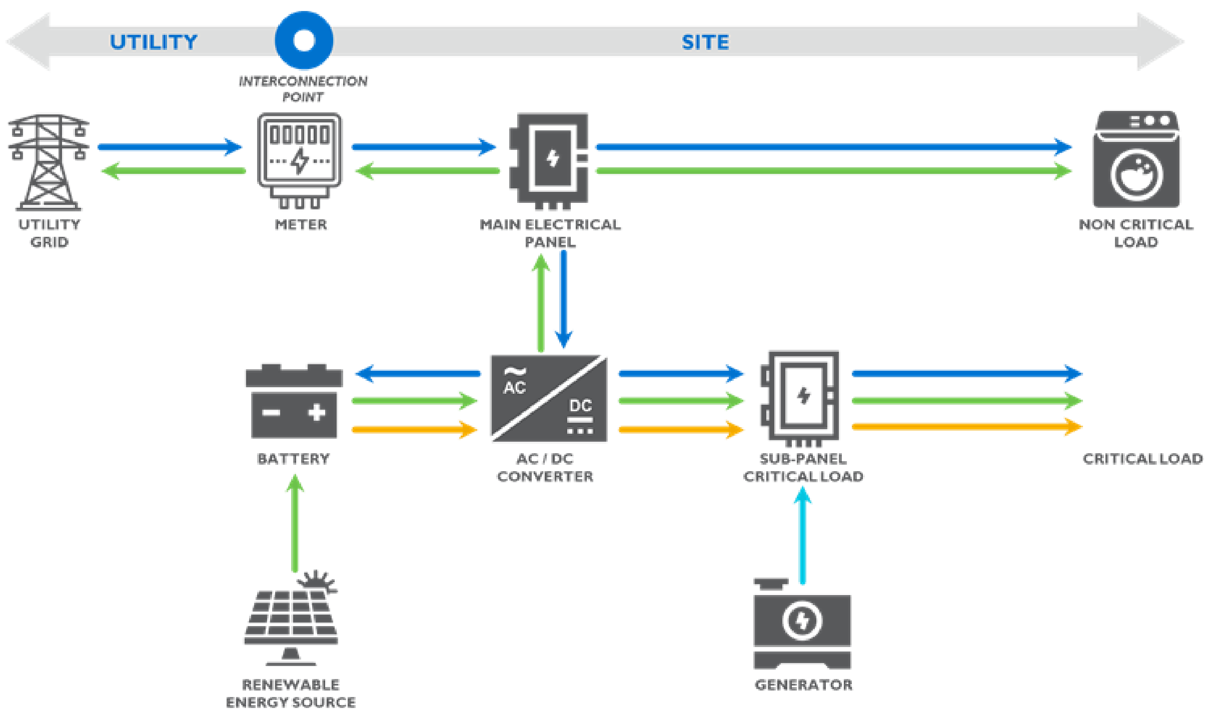


Figure 2. BTM Islandable BESS

Any BESS will require supporting components and/or auxiliary systems. These electrical components can consist of wiring, conduits, distribution panels, transfer switches, disconnects, and/or mechanical ventilation/air-conditioning. Typical infrastructure upgrades that would be required for resiliency are:

- Separate panel & rewiring (subpanels)
- Targeting existing loads with existing generation (rewiring)
- Specific hardware that will be necessary to island the facility such as transfer switches or double throw safety switches

Technology Operating Model

Liberty proposes to own the BESS so charging and discharging of assets can be optimized to support resiliency. Liberty will engage leading BESS technology providers to participate in the Program and will coordinate the automated charging and discharging optimization schemes while factoring in the performance requirements of each system. Liberty will oversee that these operating parameters for each installation conform to the technology providers' approved specifications related to frequency of cycling, minimum state of charge, and other key requirements.

In addition to programming the BESS to provide resiliency during outages, in time, Liberty will explore using these installed BESS systems to discharge during the anticipated monthly peak demand per the Services Agreement with NV Energy. Liberty's cost of electricity is driven by the highest instantaneous peak demand in aggregate across all customers. In the potential peak reduction use case, Liberty's grid operators would manage charging and discharging to find the optimum time for monthly peak demand reduction, while ensuring the systems operate within the technology vendor's approved parameters.

Technical Assistance for Large Customers

The Program will offer up to $15,000 of consultation services to provide large commercial customers with a technical BESS feasibility assessment of their facilities. This assistance is essential to achieve significant Program participation across this customer segment. By engaging large commercial customers to participate in the Program, rather than exploring and implementing similar solutions on their own with vendors, higher customer participation strengthens the benefit-cost ratios across the entire Program.

This technical assistance benefit will be assigned as a credit to large customers, only if, after the technical and financial feasibility of a project is deemed viable, the customer chooses to participate in the Program; should customers choose to implement a BESS independently, the technical assistance benefit will not be provided.

The technical assistance benefit will support customers with project siting, load analysis (to size the battery), interconnection support, technology provider selection, and BESS specification. Each BESS project is unique, and the Program will employ electrical engineers and expert BESS technology providers to help guide customers through the various options available.

To support customers, technical assistance experts will perform site visits and project audits to document existing conditions, critical loads, economic potential, storage size, and resiliency service and interconnection details. The customer-tailored audit results will help Liberty work with BESS technology providers to find the right solution for every customer.

Large customers will likely receive a BESS sized to support a portion of its total facility load, and customers will need to be selective to identify which rooms and equipment in their facility will remain on during an outage. Refrigerators and freezers are likely chosen to remain on, so the products and goods stored will remain fresh throughout an event. Program staff will help customers prioritize their facility back-up support.

Supplementary Resources for Medical Baseline Customers

Some medical baseline customers may be unable to install BESS in their homes, such as renters who do not receive landlord approval), but would still benefit from energy resiliency. According to the Pacific ADA, customers that rely on the following equipment will need to plan for power outages:

- Respirators, ventilators, and other devices to breathe
- Home dialysis and suctioning equipment

- Alternating air mattresses
- Emergency alert systems
- CPAP machines (sleep apnea)
- Temperature-controlled environments for people unable to tolerate high or low temps
- Augmentative and alternative speech devices
- Insulin pumps (diabetes)
- Storage of medicine that requires temperature control
- Power wheelchairs and scooters
- Lifts
- Height-adjustable beds

Liberty will identify these customers and explore ways to assist them in securing alternative resiliency options. Liberty can provide information links on the Program website and via other channels to customers who rely on medical equipment to help them plan for power outage events. Liberty can also coordinate with critical facilities as well as regional and state organizations to provide information so that customers might benefit from these resources. The list of critical facilities which receive a BESS through the Program can be referred to customers on the Program resources website. Customers could search for the critical facilities closest to their home and work and use the resources to develop a plan for power outage events.

Additionally, Liberty may consider recommending other local organizations that could provide portable battery equipment directly to medical baseline customers or Liberty may even consider a future phase of the Program in which Liberty provides a portable battery offering to customers unable to install permanent systems.

4.1.3 RaaS Program Model

The Program will leverage a RaaS model to provide customers with incentives and technical assistance to install BESS for back-up power resiliency benefits. Through BESS installation and managed charging, Liberty customers participating in the RaaS Program can power their home, facility, or business during PSPS events or other grid outages. Full customer benefits delivered through the Program are discussed in *Section 3.2.*

In this model, Liberty will own the BESS and lease the equipment to customers. Customers will make a monthly RaaS payment added to their utility bill for up to 10 years; the payments will depend on the type of customer and the size of the BESS system. Liberty will work with expert BESS technology providers to install BESS at customer sites and to maintain and operate the equipment over its life. Technology providers will configure the BESS to provide resiliency services, giving customers confidence that their home, facility, or business will remain online during an outage. The complete details on the terms and conditions will be developed after Program launch.

RaaS Payments and Customer Acceptance

Monthly RaaS payments added to customers' bills through the Program have been designed to meet the needs and limitations of each customer type:

- **Medical Baseline:** RaaS payments for medical baseline customers will be limited to a maximum of $10 per month, with customers on CARE rates paying $0. This $10 per month payment represents an 8% increase to customers' bills. Through the Liberty Stakeholder Engagement Survey #2, customers indicated that a $20 per month payment would be more than they could or would be willing to pay, so Liberty believes $10 per month will better facilitate customer adoption.

While Liberty believes the best Program engagement will come by customers paying at least a small monthly payment (e.g., $10), Liberty does have the flexibility to reduce this monthly payment through economic assistance, if needed, without significant impact on the benefit-cost analysis. For example, reducing the monthly payment to $0 through a promotional offer for half of medical baseline customers who would typically pay $10 would decrease the NPV by $33,000 and reduce the IRR by 0.8% for the customer type, while the overall Portfolio level IRR would remain essentially unchanged at 11.8%.

- **Critical Facilities and Large Commercial:** RaaS payments from critical facilities and large commercial customers are estimated to be $4,000 per month, which is based on expected total system costs and a storage system sized for facilities with an average daily energy consumption of 2,800 kWh and peak demand of 1 MW. Each customer's actual monthly payment will depend on their resiliency needs and technology selection. Through the Liberty Stakeholder Engagement Survey #2, customers indicated that a lower monthly payment (in the $2,000-$3,000 per month range) would be more palatable to them, which may be achievable depending on system costs as well as a potentially lower level of resiliency needed for their facilities. For example, a hospital with an existing diesel generator may be interested in additional storage capacity through a BESS which would provide an additional layer of energy security.

Importance of Liberty Ownership

Resiliency services provided to customers through a Liberty Program are important for many reasons. Through the Program, Liberty will buy-down much of the cost to serve medical baseline customers, who might not be able to afford the services on their own. Additionally, a formal Program provides participating customers with benefit from high-quality energy storage technologies and expert support in a region that has many hard-to-reach customers; defers and distributes up-front costs to customers, which could be otherwise prohibitive; and provides ongoing operations and maintenance to support peak performance of the installed systems over their lifetime.

Liberty ownership of the energy storage system assets through the RaaS model provides unique benefits, including:

- Competitive financing and volume discounts for energy storage systems through a single owner
- Ability to secure vendors who might otherwise not be available in Liberty's hard-to-reach territory, thereby providing customers with access to widest possible variety of offerings to choose from
- Confidence that energy storage systems receive proper operations and maintenance, so these assets operate optimally over the lifetime of the asset (and protect their warranties)
- Possibility for Liberty to manage its monthly peak demand and reduce costs under the Energy Services Agreement with NV Energy; while not explicitly modelled within the Program benefit-cost analysis today, Liberty ownership of these assets could help the utility operate a combination of renewable energy generation technologies combined with storage, so that variable generation can be stored to meet customer electricity demand

4.1.4 Customer Experience

Customers participating in the Program will experience the sequence of activities shown in Figure 4.

Figure 3. Program Customer Experience

STEP 1. Awareness. Liberty Resilience Specialists will develop a list of customer leads for the Program and provide outreach to customers through multiple channels.

STEP 2. Eligibility & Screening. Interested customers will submit interest forms and Liberty Resiliency Specialists will screen them for eligibility and the appropriate next step.

STEP 3. Technical Assistance (large customers only). For large commercial customers needing technical assistance to assess BESS feasibility for their business, Liberty will provide targeted technical consulting services. These service costs will be covered by Liberty, given customers elect to proceed with the BESS project through the Program.

STEP 4. Application & Enrollment. Customers will submit complete applications and upon approval, be enrolled in the Program. At this time, RaaS agreements, including terms and conditions of the Program, will be signed between Liberty and customers.

STEP 5. BESS Design & Selection. Liberty will develop a list of qualified technology providers or issue an RFP that matches BESS specifications required for customers and eligible technologies. Customers will then select and work with a Liberty-approved technology provider to design the BESS.

STEP 6. BESS Installation. Technology providers will install the BESS at customers' homes, facilities, and businesses and configure it to operate as planned.

STEP 7. BESS Interconnection. BESS will be connected to the Liberty grid.

STEP 8. Benefits in Action. Customers will begin receiving resiliency benefits through the Program.

4.2 Kings Beach Microgrid Resiliency Corridor Demonstration Project

4.2.1 Customers Served

Liberty identified the Kings Beach region as a prime target for community resiliency and proposes to deliver a community resiliency project that will serve local residential and commercial customers. Located in the North Lake Tahoe area, a grid hardening project at Kings Beach is already underway, with construction planned for 2021. The project includes the installation of covered conductors between 12 MW of existing diesel generation at Kings Beach substation and HWY 28 to keep underground portions of the Kings Beach community energized.

The purpose of the resiliency corridor demonstration proposed in this report is to identify additional grid-side investments that will foster greater degrees of resiliency for this key community core. Leveraging the existing investments, Liberty intends to add select microgrid technologies to optimize the diesel assets; thereby, providing maximum resiliency to an estimated 2,600 customers within the designated circuit areas.

4.2.2 Offering: Technologies and Approach

Purpose

As noted above, the project approach is to build upon existing grid hardening investments and identify, install, and operate complementary equipment to maximize the efficacy of these investments at minimal costs. In the long run, this approach can serve as a benchmark for future resiliency corridors—either identified and targeted by Liberty or in response to community microgrid initiatives. The main benefits of pursuing this demonstration project, beyond maximizing the value of currently planned investments, are three-fold:

1. **Demonstrate successful delivery:** Leverage the project as an effective test, through a manageable, bounded grid-side investment scope.
2. **Demonstrate value:** In a real-world setting, measure the performance and value of the investment to inform future efforts.
3. **Consider stakeholder feedback:** Introduce the concept of resiliency corridors to customers and communities to confirm or adjust messaging and approach.

Technology and Fit for Need

Current generators at the Liberty substation are sized at a collective 12MW nameplate capacity; the Kings Beach substation load is rated at 10MW. This sizing covers multiple circuits and exceeds the total anticipated load within the Kings Beach corridor. The following list reflects the equipment needed to maximize resiliency for this corridor, including quantity and costs:

- Remote-controlled distribution switch
- Remote-controlled substation switch
- Substation-based microgrid controller and setup

These incremental investments are deemed complementary to the existing generation capacity at the substation. Therefore, given that the generators had previously been sized to accommodate community core resiliency for a pre-defined period, these investments are proposed to augment those generators. As a result, these investments create a buttress against disruptions within the corridor to allow for the generators to continue to electrify the area under variable conditions. For example, fluctuations in power quality, frequency, and voltage can be detected and responded to as to allow the generator to continue to run. This correction may be simple, as in the case of voltage support, or more dramatic, as in the case of curtailing specific load pockets temporarily to maintain system balance within the targeted circuits.

Project Approach

An automatic islanding schema will isolate the generators from the grid supply. This will allow the load to be picked up by the diesel generators when the grid supply has failed. The most straight forward design is to have an automatically operated switch that will allow operations to switch between the sources. This will result in a momentary outage when switching between the sources. There are more complex designs (such as parallel operation) that would allow the system to avoid a momentary outage when switching from generation back to transmission. These generators are already set up for parallel operation so that in the event of a PSPS, they can be spun up and synced with the system. In the event of a large outage, these units would need to be black started.

The load side breaker on the transformer would be remotely / automatically operated to minimize the time to isolate the transmission and restore to the transmission source. SCADA in the substation would monitor the loading on the circuits, enabling the microgrid controller to protect the generator from an overload.

The ability to sectionalize the circuit remotely will also help with monitoring and shedding load. In the case the generator is unable to serve the load, the ability to reconfigure the circuit to shed load will help stabilize the circuit in N-1 scenarios. Some customers will see an outage in the reconfiguration, but it would prevent the entire circuit going out as the generator trips off.

Another crucial factor is controls. Controls can be centralized or decentralized. A centralized control system would be a microgrid management system. This is a piece of software connected to the various substation and distribution equipment. Advanced applications within the software will help manage the microgrid. Decentralized provide similar functionality, but at the substation level. There are pros and cons of each of these approaches. This analysis considered decentralized control; the controller would need to be configured to operate as desired for the King's Beach application. In addition, the controller must be integrated with the other devices (substation and distribution) on the circuit.

The power quality of the circuit will be controlled by the generator and existing capacitor stations and regulators running on local controls. Potentially, the local controls will have to be reviewed to enable the microgrid. A volt-var optimization analysis on the circuit could provide the ability to execute a voltage remediation plan to further improve power quality. Future investments in communications and controls could allow for some demand reduction during N-1 operations.

4.3 Phase 1 Benefits and Costs

Through a technical and business analysis, Liberty identified the following costs to deliver the Portfolio Phase 1 and expected benefits to be produced. This section covers these benefit and cost components, presents the analyses results, and discusses financial and other metrics indicative of Portfolio success.

4.3.1 Costs

Customer Resiliency Program

Liberty's benefit-cost analyses (BCA) accounted for the following cost components of the Program:

- Equipment costs for BESS
- Operation and maintenance costs for BESS
- Administration costs for Program design, marketing and outreach, and execution activities

Appendix B provides detailed descriptions of cost categories and assumptions used in the modeling. Designing the Program to address multiple customer types provides benefits to each. In this model, Liberty proposes to highly subsidize equipment costs for medical baseline customers who might not otherwise be able to participate. Liberty also proposes covering the costs of Program administration, benefiting all customers in selecting and installing high quality technology. The programmatic outreach and marketing efforts would meaningfully expedite the exposure to system options and storage project cycle. Additionally, Liberty intends to provide technical support for large commercial customers, which is essential to attract their participation and supports the overall Program benefit-cost ratio.

Potential External Funding Sources

Affordability is essential for medical baseline customers to fully realize the Program intention for social resiliency benefits. For this reason, Liberty has highly subsidized the monthly RaaS payment for medical baseline customers to achieve a $10 maximum and will seek to further reduce this cost as much as possible in finalizing the Program design. Additionally, medical baseline customers on CARE rates will pay $0 in monthly RaaS payments.

Liberty has initiated preliminary research to explore external state and federal funding sources, which may further reduce medical baseline and other customers' RaaS payments. Upon Program approval, Liberty can expand this research and consider applying for relevant funding sources available to the utility. Other funding sources may be available to customers directly, and Liberty can identify, guide, and support customers in accessing funding to help offset RaaS payments. For example, the Department of Homeland Security (DHS) has announced a new round of funding for communities through their 2021 Building Resilient Infrastructure and Communities grant program. Funding and other resources available through this or similar sources may support Liberty customers participating in the Program.

Kings Beach Microgrid Demonstration Project

Equipment costs to enable the Kings Beach microgrid resiliency corridor demonstration project are estimates based on a preliminary, high-level design. Refer to *Appendix B* for more information.

4.3.2 Value Streams

Liberty's BCA accounted for the following benefit components associated with the Portfolio Phase 1:

- Societal resiliency value
- Avoided energy contract costs
- Potential utility benefits
- RaaS payments

Appendix B details each benefit category as well as the assumptions used in the benefit-cost model.

4.3.3 Benefit-Cost Summary

The following table displays the overlaying costs and benefits with expected customer participation and performance metrics for the Portfolio Phase 1 proposal. The results are shown for the Kings Beach microgrid demonstration project and for each targeted customer group participating in the BTM Program. All values are in net present value (2021$) over the analysis period of thirteen years.[10]

Two sets of financial metrics are presented, one without societal resiliency values and another with. The first four lines under financial metrics *without* societal resiliency values represent values exchanged with direct Liberty involvement, while the last four lines *with* societal resiliency values underscores the importance and financial upsides of pursing the proposed resiliency initiatives that minimizes potential losses experienced by the local community during power outage events, outside of accounting ledgers.

[10] System installations will take place over the initial three years, and the systems will have a 10-year of equipment useful life.

The table also presents both the benefit cost ratio (BCR) pre- and post-tax treatment. The post-tax BCR of greater-than-one shows the proposed Program's cost-effectiveness with the reduction in tax liability. Lastly, the BCA results do not account for the federal investment tax credit. *Appendix B* provides details on this and other assumptions used in the benefit-cost model.

Portfolio Phase 1 - Lifetime Present Values					
	Kings Beach Microgrid Demonstration	BTM Customer Resiliency Program			Combined
		Medical Baseline	Critical Facilities	Large Commercial	
Total BESS Capacity (MWh)		5	32	19	**55**
Total Projects		117[11]	35[12]	21	**173**
Costs					
Equipment Costs	($2,039)	($3,027)	($20,553)	($12,009)	($37,627)
O&M Costs	$0	($63)	($436)	($255)	($755)
Administration Costs	$0	($769)	($930)	($1,087)	($2,787)
Benefits					
Societal Resiliency Value	$16,814	$78	$30,384	$79,251	$126,528
Avoided Energy Contract Costs	TBD	$464	$3,190	$1,864	$5,517
Potential Utility Benefits		$0	$0	$0	$0
Resiliency Payments		$46	$17,123	$10,004	$27,173
Financial Metrics					
NPV w/o Societal Resiliency Value	To Be Demonstrated	($1,512)	$3,937	$2,037	$4,462
IRR w/o Societal Resiliency Value		-15.2%	14.5%	13.4%	11.8%
Pre-Tax BCR w/o Societal Resiliency Value		0.13	0.93	0.89	0.79
Post-Tax BCR w/o Societal Resiliency Value		0.61	1.18	1.15	1.35
NPV w/ Societal Resiliency Value	$14,776	($1,434)	$1	$81,289	$94,632
BCR w/ Societal Resiliency Value	8.25	0.15	2.31	6.83	3.87
Other Metrics					
Average Monthly Resiliency Payment	[redacted]	$7[13]	$4,028	$4,028	[redacted]
Average Typical Monthly Bill	[redacted]	$85	$10,923	$54,209	[redacted]
Resiliency Payment as % of Mo. Bill	[redacted]	8%	37%	7%	**12%**
Resiliency Payment as % Total Costs	[redacted]	1%	78%	75%	**66%**

Table 3. Resiliency Program Benefit Cost Summary

[11] Liberty assumes 40% of total Liberty medical baseline customers will participate in the Program.

[12] Liberty assumes 40% of total critical facilities and large commercial customers will participate in the Program.

[13] Represents the effective Average Monthly Resiliency Payment for the portion of the medical baseline customers who contribute the $10/month payment. This is the discounted value over the system lifetime of ten years.

5 Portfolio Phase 2: Resiliency Corridor Program

5.1 Target Sites and Participants

As depicted through the Kings Beach demonstration project in Phase 1, the Resiliency Corridor Program model in Phase 2 is designed as a circuit-specific, front-of-the-meter microgrid focused on providing resiliency services to that specific geographic corridor. The thrust of this program is to provide prioritized communities with resiliency. In the future, targeted communities may be identified by Liberty or may emerge as a result of community-led microgrid initiatives.

In the case of the former, Liberty will identify priority corridors based on multiple criteria, including but not limited to economic or social criticality, at-risk status due to wildfires or storms, and at-risk status due to asset condition/useful life. In these cases, Liberty may pursue necessary grid hardening capital projects similar to those at Kings Beach as separate application and propose the Resiliency Corridor Program as a specific set of related investments. Conversely, in the case of community microgrid initiatives, community members would pursue their own BTM asset investments and seek grid-side complementary investments from Liberty.

However, these resiliency corridor projects are not intended to be offered to the exclusion of potential participation in Liberty's BTM Customer Resiliency Program. It is very likely that in any given resiliency corridor, there will be medical baseline and critical facility customers with an interest in BTM Customer Resiliency Program participation. These enrollments are not contradictory or duplicative, but rather offer two forms of additional value: 1) additional resiliency assets within a targeted corridor, which extends the value of the corridor investment by providing additive support and flexibility and, 2) allows customers with specific needs to secure their operations, whether or not the resiliency corridor services are initiated.

By selectively combining resiliency corridor efforts and customer-sited investments, Liberty can provide critical facilities and medical baseline customers with additional assets on their side of the meter. For example, critical customers, such as hospitals, water treatment facilities, or medical baseline customers, may be best served by BTM applications even when those facilities exist within a resiliency corridor. In that case, Liberty will help customers navigate the best options for participation in the Portfolio.

Thus, in its totality, the Resiliency Corridor Program could include a combination of customer-owned and utility-owned assets located in an area where significant societal impact occurs due to outages. However, Resiliency Corridor Program investments will be focused on grid-sided assets and controls. Considering the size of the Liberty territory, this model may focus on four to five locations throughout the territory. For example, certain Kings Beach investments, in the North Lake Tahoe resiliency corridor, are already underway with planned construction in 2021.

5.2 Approach

While one approach to the Liberty Resiliency Corridor Program is described and will be demonstrated through the Kings Beach microgrid demonstration project, the alternative community-driven approach to resiliency corridor projects will look significantly different. In addition to accommodating the grid-side investments, this approach will provide technical assistance and support to specific community cores as they explore the option for microgrids. Liberty's suggested steps for this approach leverage the work already completed by the CPUC-approved PG&E Community Microgrid Enablement Program[14]:

STEP 1. Vetting and Determining Feasibility. Liberty will work with community representatives that are seeking a resiliency solution for a community core. Liberty will utilize a team of Resiliency Specialists that will help the community understand options available to them and share basic grid characteristics in the area that may impact the extent of likely upgrades needed under different scenarios. Feasibility criteria is not limited but may include the following:

- **Facility Composition:** Locations with a concentration of critical facilities are scored highly
- **Historical Reliability/PSPS Risk Profile:** Locations with lower historical reliability and high PSPS risk are scored highest
- **Distributed Energy Resource (DER) Penetration:** Locations with high DER penetration is favorable, such as potential for district energy thermal with combined heat and power, biomass, etc.
- **Stackable Benefits:** DER integration, load shifting/smoothing, voltage/frequency regulation
- **Avoid/Defer System Upgrades:** The closer the existing equipment is to its maximum rating, the more favorable the location
- **Land Available/Site Prep:** Practical deployment considerations such as the availability of land and the complexity of site preparation

STEP 2. Solution Identification. In this step, Liberty will provide more specific technical guidance and support to the community and its technical/engineering partner(s) according to the type of resilience solution being sought. Liberty may require more detailed information about the core facilities and their loads as well as any service planning upgrades needed. Solution identification support could include the following:

- Training on grid data tools
- Limited microgrid design support
- Tariff application guidance, if applicable
- Tariff and interconnection policy support
- Investigation into energy efficiency opportunities, additional controllable loads, and potential for demand response
- Microgrid islanding study and consultation, if applicable

STEP 3. Execution. In this step, Liberty will provide continuing support for eligible solutions up to project commissioning. Liberty's Resilience Specialists will provide ongoing program management and coordination. This may include support with necessary agreements including a microgrid operating agreement (i.e., MOA) or special facilities agreement (i.e., SFA) to obtain eligible cost offsets for special facilities and control and communication integration support. Liberty will engage with different market actors to support implementation of the microgrid. This could be done through a shortlist of approved microgrid developers, requests for information, or even hosted within Liberty as an engineering, procurement, contractor engagement.

[14] https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5918-E.pdf

5.3 Technologies

The type of grid-sided technologies needed and proposed for any future Resiliency Corridor Program will be aligned with the proposed investments in the Kings Beach corridor as described previously in this report. The sizing and quantities of the equipment will be dependent upon the overall size of the resiliency corridors, the number of customers, and the associated loads to be served. This will be determined on a case-by-case basis.

6 Portfolio Implementation Plan

Upon approval from the CPUC, Liberty will enact the following implementation plan for Portfolio development, launch, and ongoing administration as detailed below.

6.1 Portfolio Design and Administration

Liberty will develop the final Portfolio design for Phase 1, including the BTM Program serving medical baseline, critical facilities, and large customers as well as the Kings Beach demonstration project. Through an important initial planning phase, Liberty will establish:

- **Portfolio Goals & Objectives:** Goals and objectives for the Program and demonstration project will be further refined to ensure the Portfolio addresses the most critical customer needs while aligning with Liberty business and regulatory priorities.
- **Detailed Program & Project Design:** Liberty will develop a comprehensive scope and final budget for the Program and demonstration project, not to exceed the proposed Portfolio budget which the CPUC may approve. Strategies and tactics will also determine the operations needed to meet stated goals and objectives. In developing the design, Liberty will reserve bandwidth to conduct any additional stakeholder engagement as needed.
- **Implementation Approach:** An effective implementation approach will be developed to take the Program and demonstration project from design and preparation stages through launch and successful delivery.
- **Coordination with Grid Modernization Efforts:** As the Portfolio is implemented, Liberty will coordinate with its ongoing grid modernization efforts, so no duplicative or contradictory investments are made. This includes allowing for the extensibility of the Program to eventually be integrated with a DERMS (Distributed Energy Resource Management System), should grid modernization plans call for that investment. Furthermore, it will be essential that the microgrid controller and the operational strategy associated with this investment be aligned with grid modernization investments and associated operations plan.

Customer Resiliency Program

Once the CPUC approves the Program plan and design, Liberty will implement and administer the Program, overseeing effective operations through the following process:

Technology Provider Recruitment: Liberty will recruit and select reliable BESS technology providers for the Program. Approved vendors will work directly with customers to install solutions for their homes, businesses, and facilities.

Marketing & Outreach: Liberty will provide high-touch customer engagement services to increase community awareness and simplify Program participation, including general awareness campaigns, direct outreach, and customer support.

Pipeline Management: Liberty will oversee the pipeline of customer projects and will ensure a consistent flow within Program eligibility requirements and the Program timeframe. Issues or challenges will be addressed to support Program targets.

Technical Assistance: In coordination with technology providers, Liberty will provide technical expertise and tools to support customers in equipment implementation. Liberty will ensure proper grid interconnection and control.

Quality Assurance: Thorough documentation, data exchange, and project reviews, Liberty will ensure systems are operating as expected so that any risks are mitigated.

Reporting: Liberty will monitor system operations and performance on an ongoing basis and will report meaningful Program metrics on an annual basis.

Kings Beach Demonstration Project

Liberty will implement the Kings Beach microgrid resiliency corridor demonstration project as enhancements to its ongoing grid hardening efforts in the region. To add the proposed equipment, Liberty will undertake three phases:

1. **Planning and Design:** Liberty will develop a strategic plan for project implementation and develop the technical system design.
2. **Procurement and Installation.** Liberty will procure reliable, high-quality technologies and install them within the planned configuration.
3. **Construction and Commissioning:** Liberty will construct the final project and ensure it operates as planned through commissioning.

6.2 Portfolio Resourcing

The Portfolio will be administered by Liberty, although Liberty may consider securing additional external consultants to support Portfolio implementation and ongoing operations. Based on the proposed scope, Liberty has identified the following staff needed to deliver the Customer Resiliency Program and has included these in Program administration costs:

- **Program Manager**: Oversight for Program design, implementation, and operations.
- **Technical Experts:** Energy system and BESS experts to provide technical assistance to large customers and support additional technical aspects of Program development and delivery.
- **Resiliency Specialists:** Interface with customers from initial interest through enrollment and selection of a technology provider. Manage the pipeline of potential projects.
- **Marketing & Outreach:** Drive customer lead generation through dynamic, multi-channel marketing and outreach activities.

Additionally, costs presented for the Kings Beach microgrid demonstration project include installation services from technical experts.

6.3 Portfolio Safety

Safety is a foremost priority for Liberty's Portfolio and will be given significant and meaningful attention through implementation and operations. Upon approval of the Portfolio, Liberty will develop comprehensive safety standards that integrate with the forthcoming comprehensive Portfolio design and its administration. All Portfolio support functions will conform to these standards, from field services to IT/cybersecurity and other operations areas. Standards will apply across Portfolio components and will align with established Liberty safety guidelines.

7 Portfolio Synergies

7.1 Transportation Electrification

The CPUC's rulemaking to continue the *Development of Rates and Infrastructure for Vehicle Electrification (DRIVE)* proceeding seeks to, among other things, facilitate vehicle-grid integration (VGI) policy for all California utilities. Towards this end, the CPUC established the VGI Working Group, which identified one of its policy areas as the need to accelerate use of electric vehicles (EVs) for bi-directional non-grid-export power and resiliency backup, including for PSPS events. In its December 17, 2020, decision, the CPUC accepted the working group's recommendation and directed the large utilities to implement VGI pilots that would explore EV's role in supporting system resiliency. Liberty is not mandated to deploy these pilots but considers VGI strategies in future transportation electrification filings.

Recognizing that 52% of the homes in the Liberty service territory are second homes and, therefore, residents' vehicles are be registered and maintained in different jurisdictions, it is difficult to conceive of a program at this time that would fulfill the resiliency benefit presented by VGI working group. However, given the progression of the EV market, state-sponsored initiatives, and general technological progress, Liberty will continue to monitor opportunities to engage VGI as a tool in its resiliency kit in future years.

7.2 Grid Modernization

As noted previously, one of the key synergies related to the Portfolio is the development and implementation of Liberty's grid modernization strategy. A grid modernization strategy will address a variety of key enabling building blocks that can foster cost-efficient extensibility of these preliminary resiliency investments. Systems such as an advanced distribution management system and DERMS—as well as investments in advanced meter infrastructure, and advanced sensors and communications, and distribution automation—all support and extend both the BTM resiliency program as well as the resiliency corridors concepts. In time, these aligned investments can both lower overall costs and extend the capabilities of investments.

7.3 Capital Projects

The Portfolio as described herein also offers Liberty and its customers the opportunity to align capital projects with system resiliency without overburdening these projects. Because the investments are partitioned into segmented offerings, and thus separate applications, each recovery request is cost-controlled. Furthermore, as each investment aims to build upon a previous investment, as in the case of the proposed Kings Beach microgrid demonstration project building upon Liberty's ongoing existing generation and conducting projects, the subsequent investments extend the value of the previous investment. This both ensures alignment of efforts and increases the likelihood and amount of benefit realization to the Liberty customers.

8 Appendix A: Resiliency Needs Assessment

Through the design of the Portfolio, Liberty developed a replicable framework by which to assess its territory for resiliency needs and priorities, now and in the future. This framework comprised:

- **Layer 1.** Understanding the high hazard probability and locations that are most at risk of wildfires, PSPS, and winter storms. This is a future looking analysis.
- **Layer 2.** Identifying circuits with current disruption challenges and typical outage lengths.
- **Layer 3.** Exploring the percentage penetration of critical customers, which includes critical facilities as defined by the CPUC and medical baseline customers.
- **Layer 4.** Investigating areas that have large societal and economic impact due to outages. For example, areas like Kings Beach which if offline for multiple days would cause distress to the local economies.

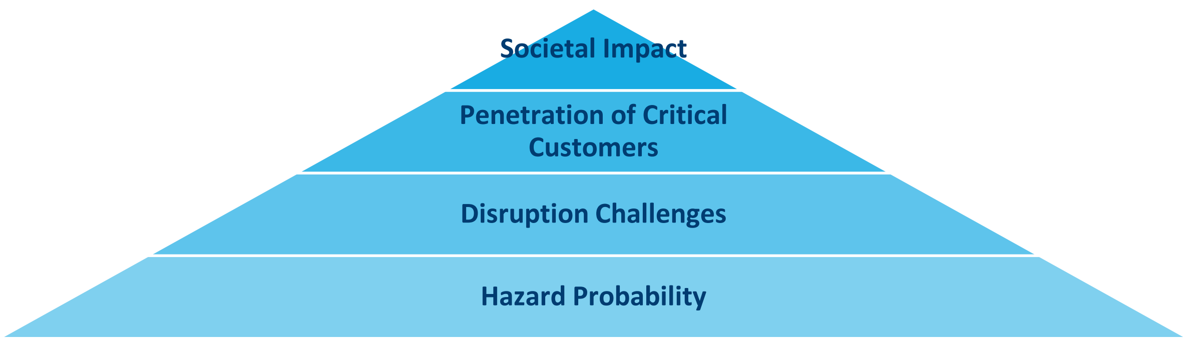


Figure 4: Resiliency Prioritization Framework

Applying this framework, Liberty validated the need for energy resiliency across its territory, amidst ongoing hazards. This analysis also identified specific geographical areas at risk and prime candidate regions for development of Liberty resiliency efforts. The analysis confirmed the importance of resiliency corridors in regions like Kings Beach, and Liberty will leverage these insights for expanded resiliency corridor development for Portfolio Phase 2 as well.

8.1 Hazard Probability and Analysis

Liberty's territory sits within a mountainous zone and heavily treed area that experiences multiple hazards throughout the year. Wildfires, winter storms, and PSPS events are the main hazards expected to increase over the next ten years, growing more frequent and extreme[15]. Liberty's resiliency efforts aim to address these three major hazards experienced by customers.

Considering that Liberty is a winter-peaking utility, the impacts of increased winter storms is paramount to address with urgency. Additionally, while Liberty did not have any PSPS events in 2019, one event did occur in 2018. Liberty staff received weather reports from National Weather Service that indicated a storm was approaching with high winds and the conditions warranted a fire weather watch. This was the first significant storm of the season, and the local vegetation had not received enough precipitation to reduce the high fire danger. The PSPS event began at 12:00 PM on November 21, 2018 and lasted

[15] Michael Goss *et al* 2020 *Environ.* https://iopscience.iop.org/article/10.1088/1748-9326/ab83a7

until 3:00 PM that afternoon. The de-energized lines included lines in South Lake Tahoe, Kings Beach and Tahoe City. In total, de-energization impacted 30 customers (29 residential customers and one commercial customer). The wind and storm impacts did not develop to the extent forecasted. Liberty staff determined that the fire danger had passed, and the decision was made to restore all circuits.

In 2019, neighboring utility PG&E experienced multiple PSPS events causing outages ranging from 3 to 16 days[16]. Considering the changing climate and projected shifts, Liberty is expecting PSPS events to become more frequent and necessary to protect from future wildfires, and therefore taking a proactive approach in developing this effort to ensure resiliency for customers.

8.2 Disruption Challenges

While Liberty disruption metrics are in the middle of the California investor-owned utility (IOU) average, identifying the locations that experience the most outages within the territory ensures resilience planning targets the most vulnerable circuits and against the most common causes. When investigating opportunities for resiliency opportunities, the Liberty team is looking at times when larger customer groups are offline, which could be an entire substation or circuit. These are locations is most need of resiliency services.

Figure 6 below shows the circuits experiencing the highest average interruption duration in 2019 in Liberty service territory. Targeting the top circuits most susceptible to interruptions via infrastructure hardening and resilience program efforts can affect 90% of the cumulative interruption duration. Figure 7 shows the customer minutes of interruption (CMI) by cause of interruption. Together, vegetation-related—including tree fell and broken tree limbs—and vehicle-related causes account for roughly half of all CMI experienced.

Investor-Owned Utility	SAIDI with Major Event Day	SAIFI with Major Event Day
Pacific Gas & Electric Co.	1,355	1.80
PacifiCorp	590	3.05
Liberty Utilities	417	2.96
Bear Valley Electric Service	318	2.20
Southern California Edison Co	178	1.04
San Diego Gas & Electric Co	123	0.64

Table 4: California IOU Reliability 2019

[16]https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electrical_Infrastructure,_Planning,_and_Permitting/Reliability_and_Distribution_Infrastructure/Reliability/2019_PGE.pdf

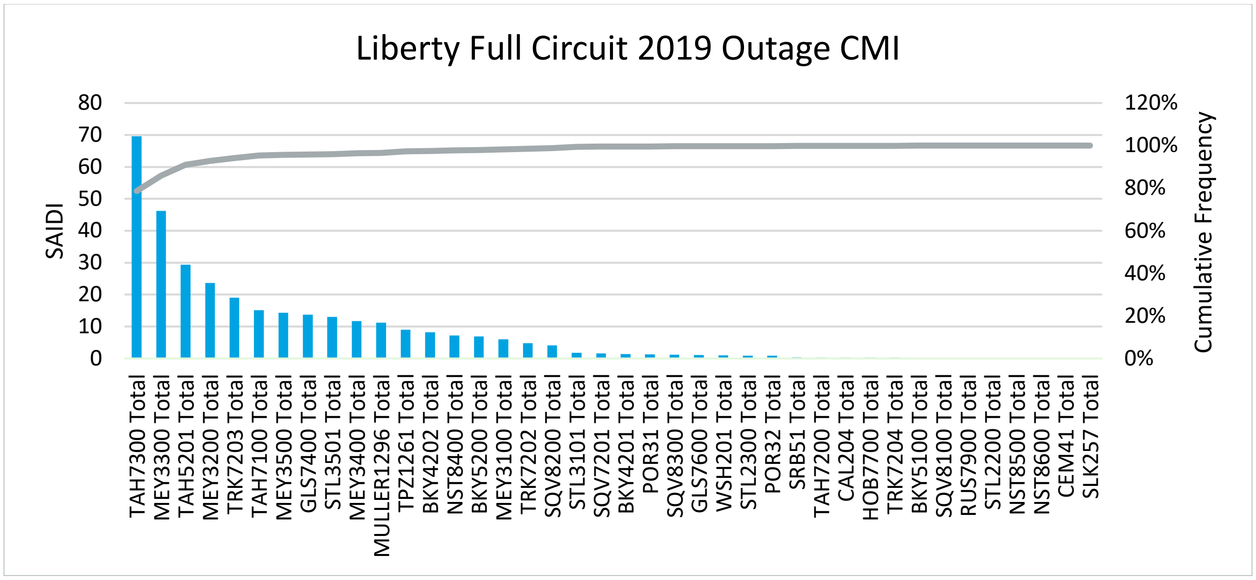


Figure 5: Top Circuit Outages

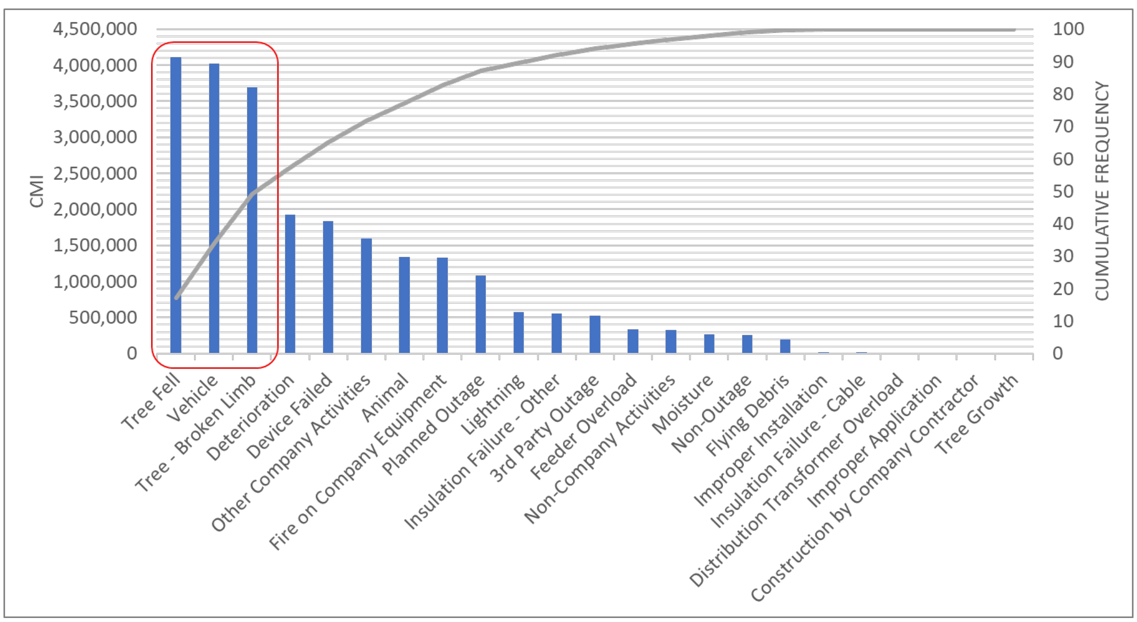


Figure 6: Customer Minutes of Interruption (CMI) by Cause

8.3 Penetration of Critical Customers

With just over 49,000 customers in Liberty's service territory, Liberty did an initial inventory and determined that critical customers make up nearly 1% of the total customers. Medical baseline customers make up 0.6% of the residential customers. Critical facilities are a mix of large, medium, and commercial customers. Initial investigation into critical facilities has identified over 89 may exist in the territory. This layer is critical to understand where resiliency services are most needed.

Customer Rate Class: 2020	Customer Count	% Total
Large Commercial	52	0.11%
Medium Commercial	232	0.47%
Small Commercial	5,261	10.72%
Residential Primary	14,473	29.49%
Residential Non-Primary	25,371	51.70%
CARE- Low Income	3,686	7.51%
	49,075	

Table 5: Customers by Customer Class

Customer Rate Class: 2020	Customer Count	% Customer Group and Total
Critical Facilities	89	1.6% Commercial 0.2% total
Medical Baseline	291	0.7% Residential 0.6% total

Table 6: Critical Customer Count

Critical customers are defined as facilities that are essential to the public safety and that require additional assistance and advance planning to ensure resiliency during de-energization events[17].

- **Emergency Services Sector:** Police stations, fire stations, and emergency operations centers
- **Government Facilities Sector:** Schools, jails, and prisons
- **Healthcare and Public Health Sector:** Public health departments and medical facilities, including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers, and hospice facilities
- **Energy Sector:** Public and private utility facilities vital to maintaining or restoring normal service, including, but not limited to, interconnected publicly owned utilities and electric cooperatives
- **Water and Wastewater Systems Sector:** Facilities associated with the provision of drinking water or processing of wastewater including facilities used to pump, divert, transport, store, treat, and deliver water or wastewater
- **Communications Sector:** Communication carrier infrastructure including selective routers, central offices, head ends, cellular switches, remote terminals, and cellular sites
- **Chemical Sector:** Facilities associated with the provision of manufacturing, maintaining, or distributing hazardous materials and chemicals

To this definition, Liberty adds customers with gas station, grocery store, and diesel fuel supply facilities. These customers supply essential goods and services—the loss of which could cause material human and economic harm to local communities.

[17] Decision 19-05-042. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M296/K598/296598822.PDF

Medical baseline customers are defined as those residential customers that participate in the Liberty Green Cross program, including those with proof of medical equipment needs provided by a physician. Within the residential Primary and Residential Non-Primary customer groups, there are 291 medical baseline customers, accounting for 0.7% of the residential groups (Primary and Non-Primary) and 0.6% total customer count.

8.4 Societal and Economic Impact

Liberty identified several target regions that are of economic importance to their communities and is taking these areas into consideration for resiliency efforts. Primary areas include North and South Lake Tahoe, which drive economic activity for much of the region and could present significant losses and distress to the broader community through extended outages. Secondary areas with more modest, but still important, economic activity include Portola, Loyalton, Walker-Coleville, and Markleeville. Figure 8 illustrates sample socio-economic factors[18] to consider through the program.

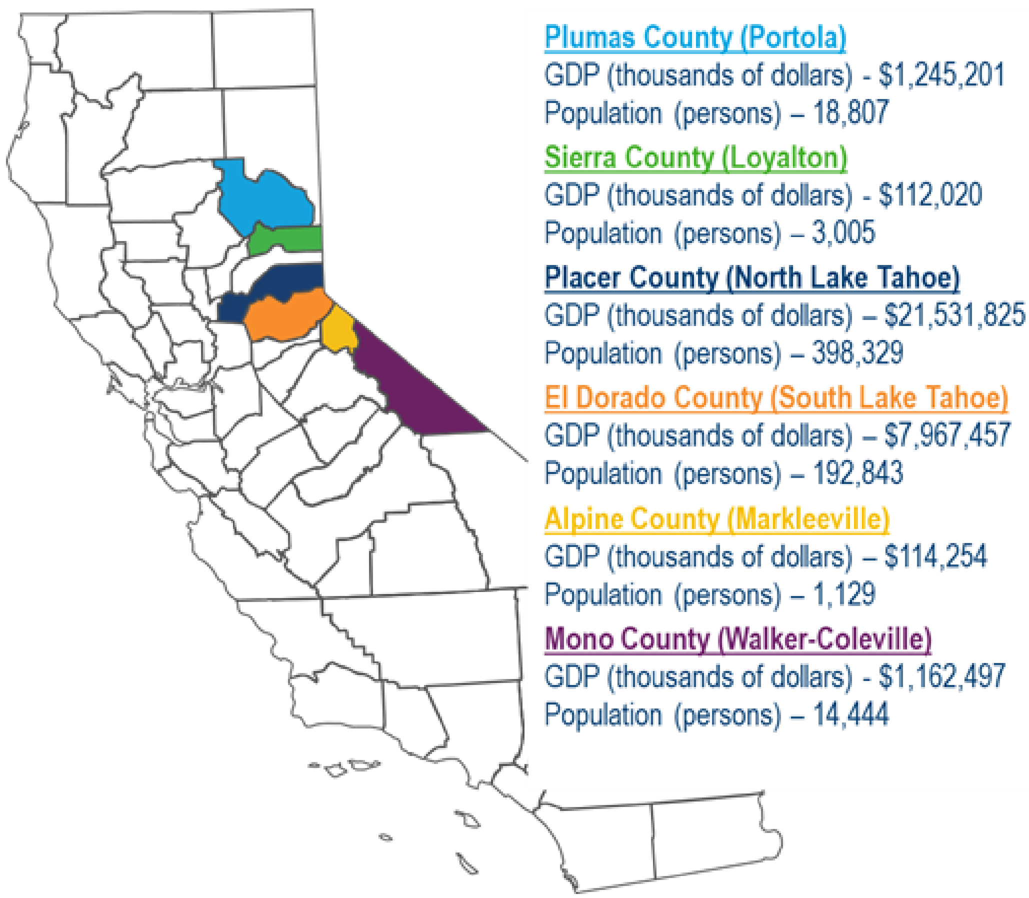


Figure 7: Regional Socio-Economic Factors

[18] https://www.bea.gov/data/gdp/gdp-county-metro-and-other-areas

9 Appendix B: Technical and Business Analysis

Liberty created a benefit-cost analysis (BCA) model to quantify the benefit and costs and assess financial viability of the proposed Portfolio Phase 1. Liberty's model utilized a discounted cash flow method, and this appendix documents the model approach, parameters, and their assumptions.

The modeling tool organizes the parameters and assumptions into two groups: sensitivity parameters and everything else. The sensitivity group captures a subset of parameters key to describing the Phase 1 business model and outcomes. Besides these sensitivity parameters, the model contains an array of parameters and assumptions that are dependent on the sensitivities parameters, as well as financial, customer site, and operational-related assumptions specific to Liberty and the targeted customers in Liberty's service territory.

9.1 Sensitivity Parameters

9.1.1 Participation

The first step in the analysis was to develop a bottom-up approach to examine energy storage capacity potential for each Customer Resiliency Program (Program) pathway at a portfolio/fleet level. The BCA model assumes a *medium* level of participation, at 40% for the critical facilities and large commercial customer groups and 40%, for medical baseline customers. Liberty then created a simple S curve (with parameters k=4, a=1) to describe the customer enrollment spread within the three-year program periods with active enrollment.

	Medical Baseline	Critical Facilities	Large Commercial
Total Population	291	89	52
Participation Level	40%	40%	40%
Participant Number	117	35	21

Table 7. Participation Level

The total Program capacity is the product of participants numbers (same as project numbers) and the average project size in MWh for each customer group. Participation assumptions for each customer type are based on the following rationale:

- **Medical Baseline:** Liberty estimates 40% of medical baseline customers will participate in the Program. This estimate takes into consideration data collected through the Liberty Stakeholder Engagement Survey #2, including: a) 80% of survey respondents expressing interest in a battery back-up power solution, and b) 50% of survey respondents indicating that they own their home (vs. rent), which would allow them to feasibly install an energy storage system. Based on this data, Liberty predicts strong participation interest among customers, while also acknowledging that some customers may not have a residence that can easily accommodate a permanent energy storage system. As noted in *Section 4.1.2*, Liberty plans to provide recommendations for alternative resiliency solutions for customers who may not be eligible for the Liberty Program due to constraints such as their status as renters.

- **Critical Facilities and Large Commercial:** Liberty expects 40% of critical facilities and large commercial customers to participate in the Program, which has been modelled in the benefit-cost analysis. This number is informed by a) Liberty's consultant, TRC, who has many years of experience with customer energy program management and similar participation rates, b) the relatively modest real number of customers 40% represents – i.e., 56 customers, and c) the high-touch outreach strategy Liberty will use to engage this customer segment in the Program.

  Additionally, through the Liberty Stakeholder Engagement Survey #1, customers expressed interest, on the order of 60% of respondents, in installing a battery back-up system. Positive indicators on this point were also collected through the Liberty Stakeholder Engagement Survey #2, but because the total number of responses was so low for Survey #2, these results may not be representative.

  To understand the possibility of a lower participation rate, Liberty has also modelled a scenario in which only 30% of critical facilities and large commercial customers may participate in the Program. Even in this scenario, the BCA only shows a modest decline to 1.30, with the IRR decreasing slightly to 10.5%.

9.1.2 Benefits Values

Societal Resiliency Values

Customer Resiliency Program

A key motivation behind pursing a resiliency Program is the societal resiliency benefits for Liberty's customers. Societal resiliency benefits include both direct benefits experienced by participants who host BTM BESS and indirect benefits to the community served by critical facilities which maintain valuable and timely emergency services during outage events.

For the Program offerings, the model leveraged the Interruption Cost Estimate (ICE) Calculator developed by Lawrence Berkeley National Laboratory[19] to approximate the site-level resiliency values experienced by medical baseline and large commercial customers. The model applied a multiplier of 1.2x in comparison to general residential customers to reflect the elevated risk and loss potential associated with medical baseline customers.

For critical facilities, the model utilized Federal Emergency Management Agency's (FEMA) Benefit Cost Analysis Toolkit[20] to calculate the societal resiliency value associated with the following facility types: hospitals, police/fire stations, school/shelters, and wastewater treatment plants. Liberty used results from FEMA's Toolkit and applied the distribution of each customer type within Liberty territory. This involved creating a composite critical facility prototype weighted by the percentage of each facility type within Liberty territory for the BCA model. The estimated per facility, per 24-hr outage social resiliency values estimated using the ICE Calculator and FEMA tools are displayed in Table 8.

[19] https://www.icecalculator.com/build-model?model=interruption
[20] https://www.fema.gov/grants/guidance-tools/benefit-cost-analysis

	Medical Baseline	Critical Facilities – Prototype	Large Commercial
Societal Resiliency Value (per facility per 24-hr outage)	$34	$43,000	$193,000

Table 8. Societal Resiliency Values

To translate the per facility, per 24-hour outage societal resiliency values into annual figures, Liberty assumes a frequency of occurrence of three 24-hour outages per year, for the duration of the analyses.

It is important to note that it is the participating customers and surrounding community at large who experience these societal resiliency values in the form of avoided losses or damage, while Liberty does not accrue these benefits directly. As a result, the model derives two separate sets of financial metrics to reflect this, one including the societal resiliency values, and the other does not.

Kings Beach Microgrid Demonstration Project

Liberty estimated the societal resiliency value for the microgrid using the customer counts and composition that will be impacted by the four feeders served by the new Kings Beach substation. There are a total of eighteen medical baseline, three critical facilities (shelters), and two large commercial customers within the substation service area.

The model assumes all three targeted customer types to be covered by the microgrid services, given their priority status and likelihood to be located off the main service line. For the rest of the customers—roughly 4,500 residential and 560 smaller commercial customers—the model applies a conservative, 50% coverage factor, to indicate that half of them will maintain service because of the microgrid during an otherwise outage event. The resulting societal resiliency value for a 24-hour outage for the microgrid is $2,383,000.

Avoided Energy Contract Costs

The model accounts for potential cost savings from reduced overall energy demand by incorporating a benefit multiplier of $101/kW per year for the Program's BESS capacity. In contrast to the societal resiliency values, the avoided energy contract costs are monetary values that manifest in Liberty's financial accounting as opposed to experienced directly by its customers.

Potential Future Grid Services

Liberty recognizes the potential for multiple additional grid services from the BTM BESS and microgrid-related resiliency efforts. These potential services include benefits pertaining to resource adequacy, energy arbitrage, operating reserves, as well as targeted transmission and distribution deferral opportunities. The model does not incorporate any values from future grid services due to the uncertainty of and complexity associated with quantifying these value streams.

RaaS Payments

The model calculated the equivalent RaaS born by critical facilities and large commercial customers by summing the BESS equipment and operations and maintenance costs—including cost of capital but excluding the Program administration costs—and spreading the cost into monthly payments over the equipment useful life of 10 years for each project.

For medical baseline customers, the model assumes that half of participating customers will pay a fixed RaaS payment of $10 per month, while the other half will not have a RaaS payment obligation.

9.1.3 Cost Values

Program Administration Costs

Liberty's estimated Program administration costs are based on prior experience with customer energy programs. Program administration costs include the support of the program design, program launch, establishing technology provider allies, conducting outreach, and performing project and pipeline management and associated reporting activities. Table 9 displays the Program costs for each targeted customer group. The model assumes lower Program costs for medical baseline customers, since residential-sized BESS specifications and install processes are standardized in comparison to the commercial counterparts.

For large commercial and industrial customers only, the Program costs also cover a technical assistance component. The model assumes that only half of the interested customers who receive technical assistance to assess the feasibility of BESS for their site will proceed with BESS installation.

	Medical Baseline	Critical Facilities – "Prototype"	Large Commercial
Program Administration (per project)	$7,500	$30,000	$30,000
Technical Assistance (per study)	NA	NA	$15,000

Table 9. Program Administration Costs

Equipment and Operations / Maintenance Costs

Customer Resiliency Program

The model utilizes the installed system cost information from the Self Generation Incentive Program database[21] and the BESS operations and maintenance cost info from a Storage Characterization report[22] by Pacific Northwest National laboratory. The equipment costs do not factor in potential costs associated with the host site installing solar PV. The $/Wh BESS capacity figure used by the model assumes this relatively lower price point accessible via group purchasing arrangement with the Program technology provider allies.

	Equipment Cost	Operation & Maintenance
BESS Costs	$0.73/Wh	$8.29/kW per year

Figure 8. Program Equipment and O&M Costs

[21] https://www.selfgenca.com/
[22] https://www.sandia.gov/ess-ssl/wp-content/uploads/2019/07/PNNL_mjp_Storage-Cost-and-Performance-Characterization-Report_Final.pdf

Through the BCA model, Liberty will own the BESS assets and be responsible for ongoing operation and maintenance through the life of the systems. In return, customers who host these BESS assets make a monthly RaaS payment for the services.

As the BESS owners, Liberty maintains an active level of control over the systems so that their operation meets the resiliency needs against planned and unplanned outages. Additionally, an *active* level of control enables Liberty to optimize the BESS operation and provide values that are beneficial to all customers in the territory. With an active system control level, Liberty assumes that 60% of the potential energy reduction is realized via coordinated management of battery state of charge and charging / discharging activities.

Kings Beach Microgrid Demonstration Project

Equipment costs to enable the Kings Beach microgrid resiliency corridor demonstration project are rough estimates based on a preliminary, high-level design. Liberty will collect additional details and create a more detailed engineering design upon Portfolio approval, at which point a more refined cost estimate will be generated. The table below provides +/- 50% budgetary estimates for investments.

Investment	Qty	Unit Cost	Extension
Remotely Controlled Distribution Switch	3	$78,000	$234,000
Remotely Controlled Substation Switch	1	$125,000	$125,000
Substation-Based Microgrid Controller and Setup	1	$1,000,000[23]	$1,000,000
		Total	**$1,359,000**

Figure 9: Kings Beach Project Equipment Costs

Note: Table represents installed equipment cost, including necessary engineering, materials, construction, etc. Within the BCA model (*Section 4.3.3*), a +50% equipment cost buffer has been added to this estimated cost to adequately balance against the estimated benefits.

9.2 Additional Parameters and Assumptions

Additional underlying parameters and assumptions for the model are listed in Table 10.

Parameter	Assumption
Program Active Period	3 years
Equipment Useful Life	10 years
Analyses Period	13 years
Depreciation Method	MACRS 7-year
Discount Rate	6.9%/year
Inflation	1.5%/year

[23] Based on a simple controller with one source versus multiple sources.

Investment Tax Credit	None

Table 10. Additional Model Parameters and Assumptions

9.3 DER Asset Sizing

Liberty performed detailed analyses to determine the sizing of DER assets for the Customer Energy Resiliency Program (Program). This section explains the process used to produce the project BESS sizing information used to estimate various cost and benefit components captured in the BCA model.

The exercise essentially created daily profiles for each building type and specified outage profiles to determine the sizes of DER assets—both BESS and solar PV —required to achieve resiliency for the three outage scenarios. The outage scenarios were evaluated for the purpose of the sizing exercise that correspond to the three durations that PSPS and other substantial outages may span: 1-day, 3-day, and 7-day durations.

The overall methodology aimed to identify technically feasible BESS to provide resiliency for targeted customer groups in Liberty's service territory. The DER sizing analysis determined the capacities of both energy storage and solar PV required to provide resiliency for the extended multi-day outages targeted by this Program. The sizing exercise estimated the sizes of both energy storage and solar PV, as islanding electrical loads for these durations inherently require some form of generation. A solar PV is a stand in for a generating source that will be needed to support outage events that are longer than 24 hours.

The DER sizing analysis was performed in Homer Grid, which combines engineering and economics information in one comprehensive model. The software rapidly performs complex calculations to compare multiple component design outcomes and provides the least-cost configuration required to meet the specified outage duration. The results of this analysis include representative energy storage and PV system sizes for each customer type and outage duration.

9.3.1 Representative Electricity Profiles

To estimate the DER capacities required to mitigate outages of each duration, representative electric load profiles were developed for each customer segment using a combination of available utility data and generic load shapes within Homer Grid.

Medical Baseline Customers

Monthly data for medical baseline customers within Liberty's service territory were used to estimate the average medical baseline customers' daily electric usage, which was calculated to be approximately 25 kWh. To develop a representative hourly profile, medical baseline customers were assumed to have a residential load shape, which was then scaled to match the average daily consumption.

Figure 10. Daily Load Profile – Residential

Critical Facilities

For each critical facility type, representative models for electric load were retrieved using Homer Grid's Open EI download module. This functionality allows the user to choose a representative building model developed by the DOE based on facility type and climate zone. The image below shows the selection within Homer for a representative Hospital in South Lake Tahoe.

Load profiles nearest your project location and within your climate zone are shown below.
Location **(38°56.4'N, 119°58.6'W)** Climate Zone **4B**

Name	Location	Distance (km)	Climate Zone	Description
Supermarket in South Lake Tahoe Lake Tahoe C	(38°56.4'N, 119°58.6'W)	0.0	4B / Csb	Supermarket model: 45,000 square feet, 1 floor.
Warehouse in South Lake Tahoe Lake Tahoe CA	(38°56.4'N, 119°58.6'W)	0.0	4B / Csb	Warehouse model: 52,045 square feet, 1 floor.
Full Service Restaurant in South Lake Tahoe Lake	(38°56.4'N, 119°58.6'W)	0.0	4B / Csb	Full Service Restaurant model: 5,500 square feet, 1 floor.
Small Office in South Lake Tahoe Lake Tahoe CA	(38°56.4'N, 119°58.6'W)	0.0	4B / Csb	Small Office model: 5,500 square feet, 1 floor.
Primary School in South Lake Tahoe Lake Tahoe	(38°56.4'N, 119°58.6'W)	0.0	4B / Csb	Primary School model: 73,960 square feet, 1 floor.
Hospital in South Lake Tahoe Lake Tahoe CA	(38°56.4'N, 119°58.6'W)	0.0	4B / Csb	Hospital model: 241,351 square feet, 5 floors.
Large Hotel in South Lake Tahoe Lake Tahoe CA	(38°56.4'N, 119°58.6'W)	0.0	4B / Csb	Large Hotel model: 122,120 square feet, 6 floors.
Large Office in Bishop CA	(37°21.7'N, 118°24.0'W)	223.2	4B / BSk	Large Office model: 498,588 square feet, 12 floor.

Figure 11. Example Representative Building Selection

The resulting daily load profile for the hospital is shown below.

Figure 12. Daily Load Profile – Hospital

This process was replicated for each critical facility type including a school/shelter, police/fire station, and wastewater treatment plant.

9.3.2 Sizing

Liberty used Homer Grid to size storage and solar for various duration outages. This software optimizes based on both normal operation and islanded operation economics. To avoid the result being driven by solely the value of net-metering solar, Liberty disallowed grid resale in the model. Consequently, the simulation results represent the optimal solar plus storage mix based on the energy needs during the outage and not by the revenue streams during normal operation. This sizing process was repeated for each facility type, and the resulting DER sizes are shown in Table 11.

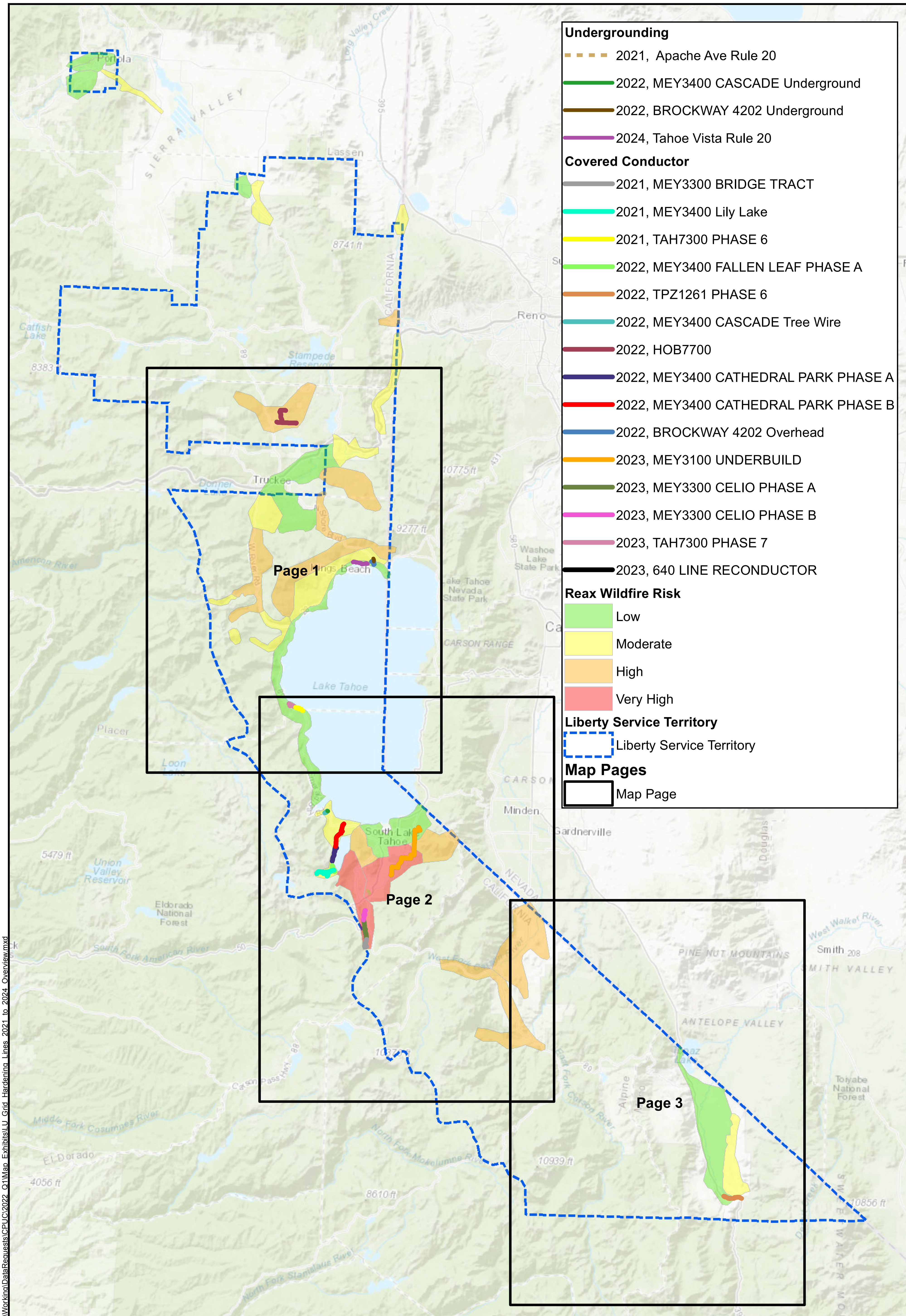
Customer Type	Average Daily Load (kWh)	Daily Peak Load (kW)	1-Day Outage PV Size (kW)	1-Day Outage BESS Size (kWh)	3-Day Outage PV Size (kW)	3-Day Outage BESS Size (kWh)	7-Day Outage PV Size (kW)	7-Day Outage BESS Size (kWh)
Residential	25	5	0	47	7	54	9	93
Hospital	22,897	1,378	3,073	8,220	6,045	16,093	6,049	15,584
School/Shelter	2,234	260	394	805	416	1,228	599	1,478
Police/Fire Station	346	33	85	172	152	250	152	250
Wastewater Treatment Plant	24,000	1,833	4,524	12,035	8,224	20,354	8,817	23,188
Large Commercial	13,700	2,306	1,791	1,737	2,327	3,937	2,617	5,211

Table 11. DER Sizing by Customer Type and Outage Durations

Note: the PV and BESS sizes shown in Table 11 are not rounded to the component sizes that are commercially available. In aggregate, this simplification is unnecessary due to the inherent uncertainty already contained in this high-level analysis. For the design and deployment of these technologies for individual customers, each component will need to be sized for its specific loads, site constraints, and according to actual product offerings in the market.

Attachment C

Maps of Liberty Covered Conductor, Pole Replacement and Fuse Replacement Projects



Liberty
701 National Ave
Tahoe Vista, CA 96148

Overview
Grid Hardening Lines
2021-2024

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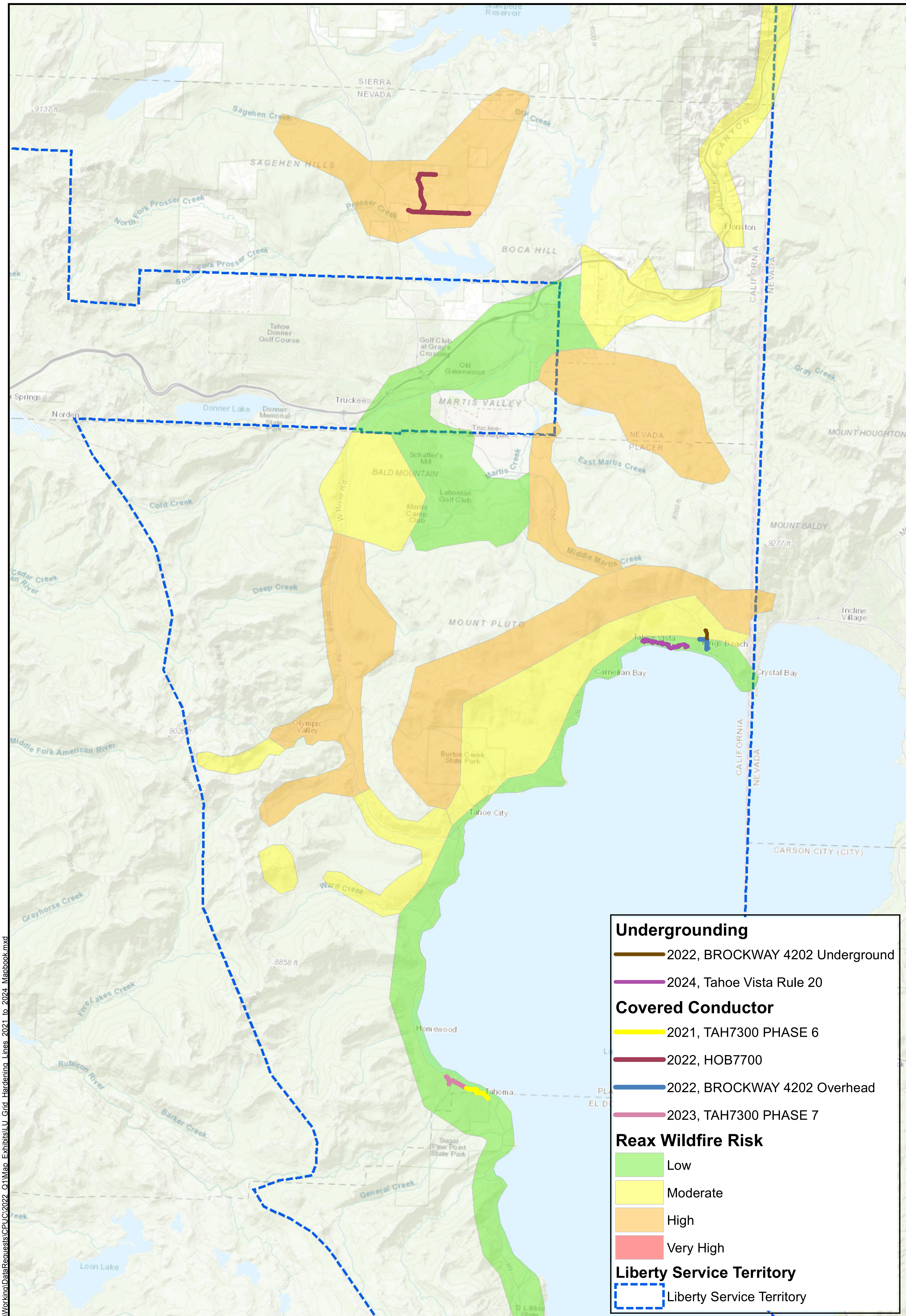
Miles

1 inch = 7 miles

Date: 4/26/2022



Liberty

701 National Ave
Tahoe Vista, CA 96148

Page 1 of 3
Grid Hardening Lines
2021-2024

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Miles

1 inch = 2 miles

Date: 4/26/2022

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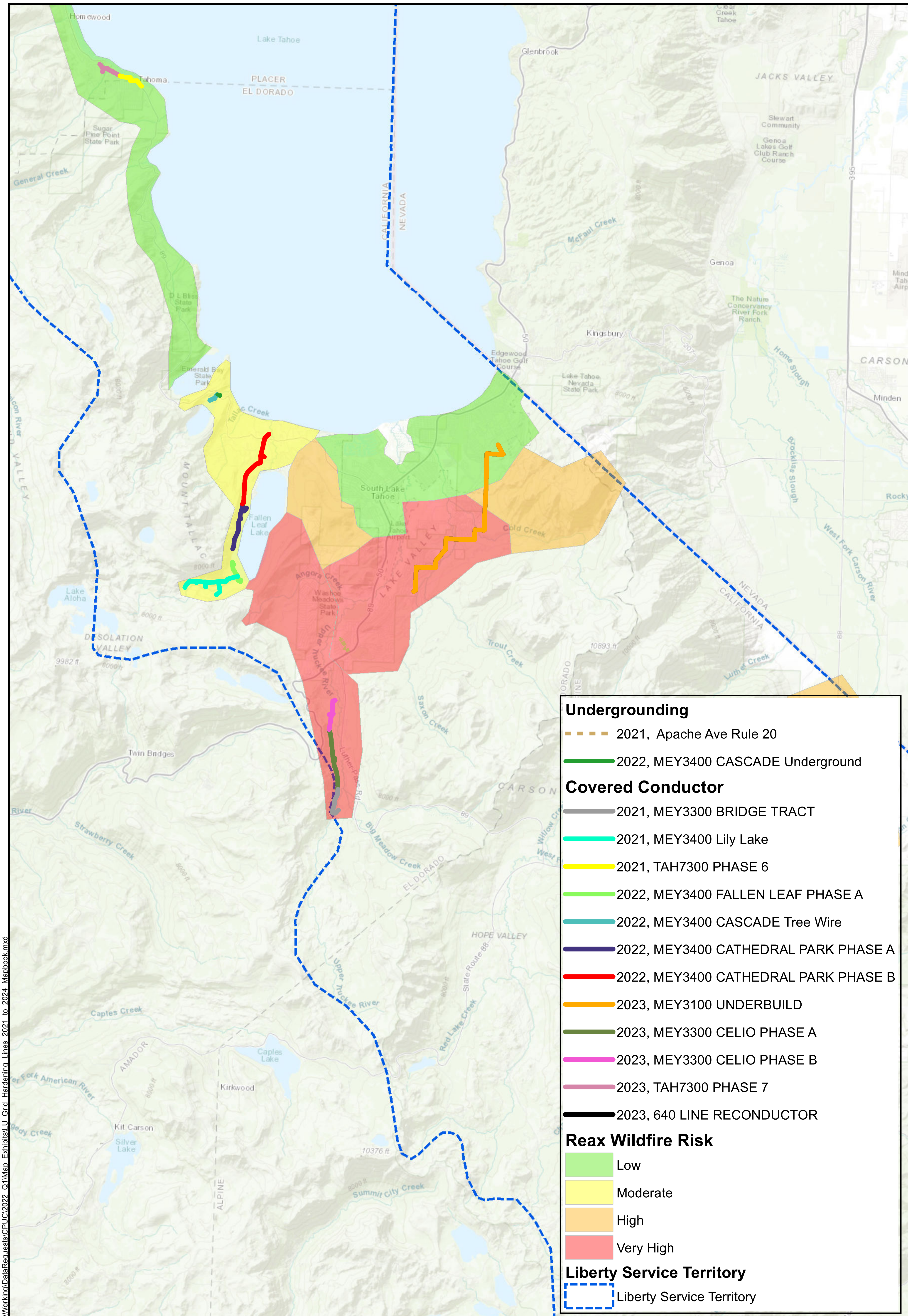

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701 National Ave
Tahoe Vista, CA 96148

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Grid Hardening Lines
2021-2024

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1 inch = 2 miles

Date: 4/26/2022

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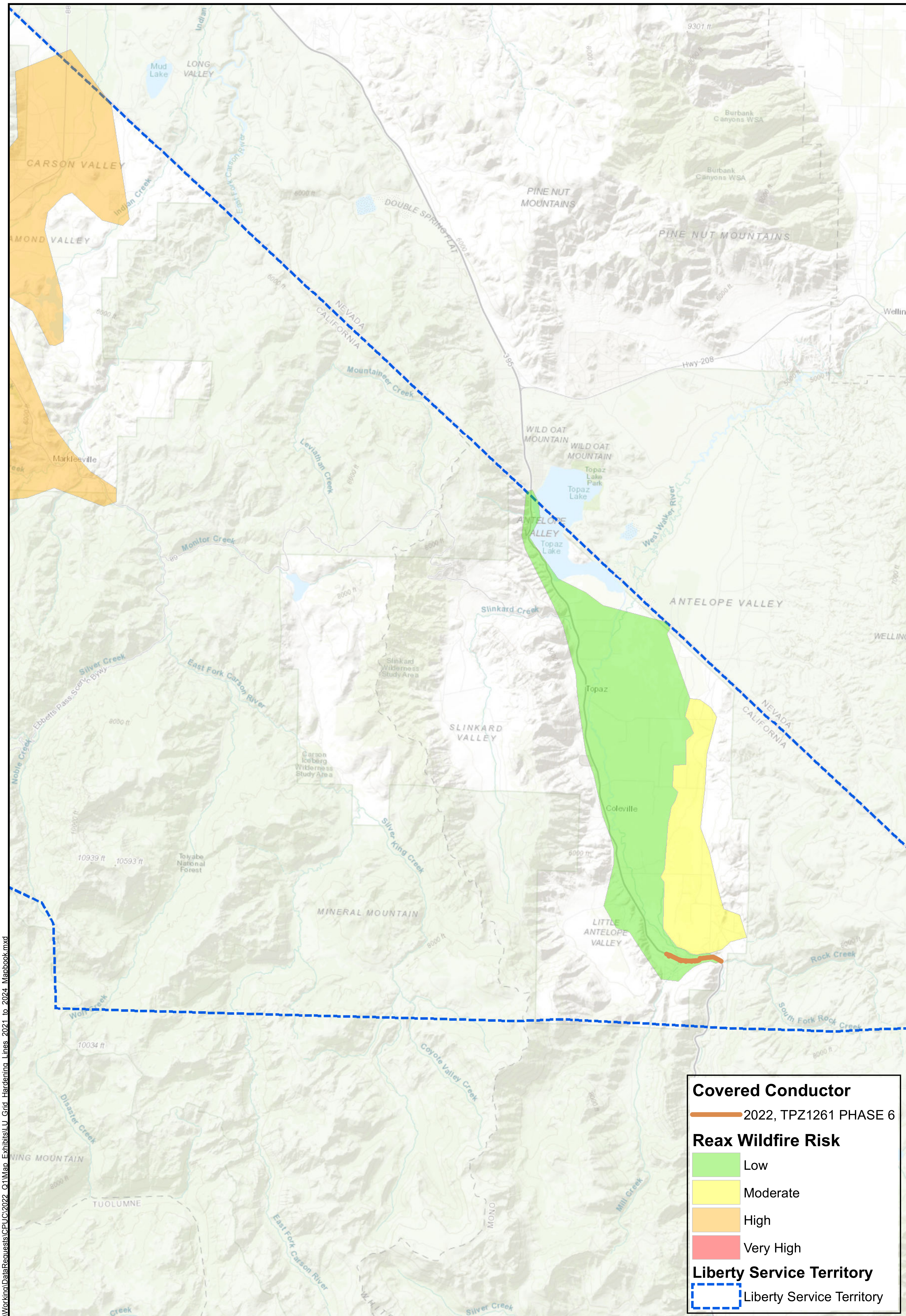

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Tahoe Vista, CA 96148

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Grid Hardening Lines
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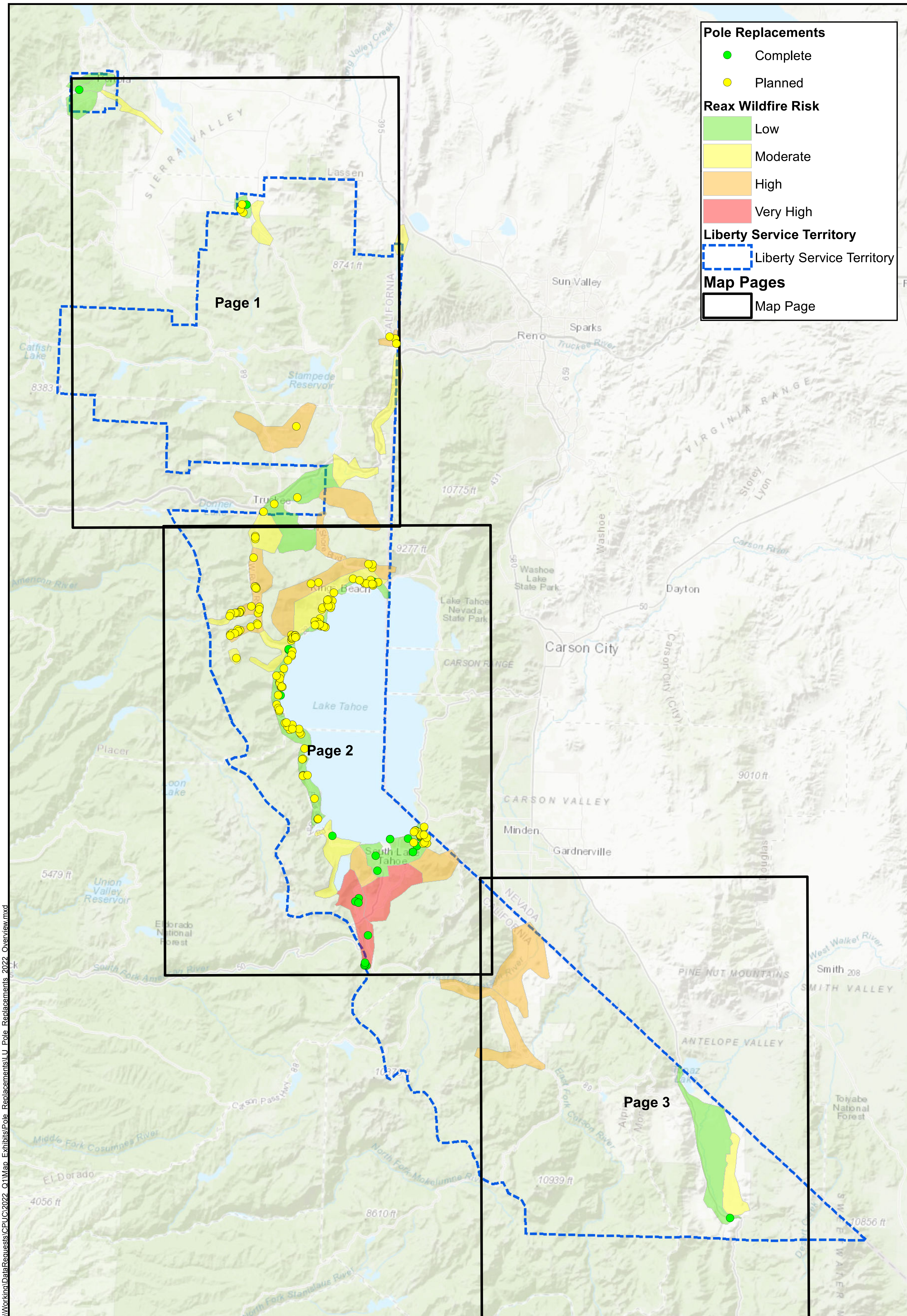

Liberty
701 National Ave
Tahoe Vista, CA 96148

Overview
Pole Replacements
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1 inch = 7 miles

Date: 4/26/2022

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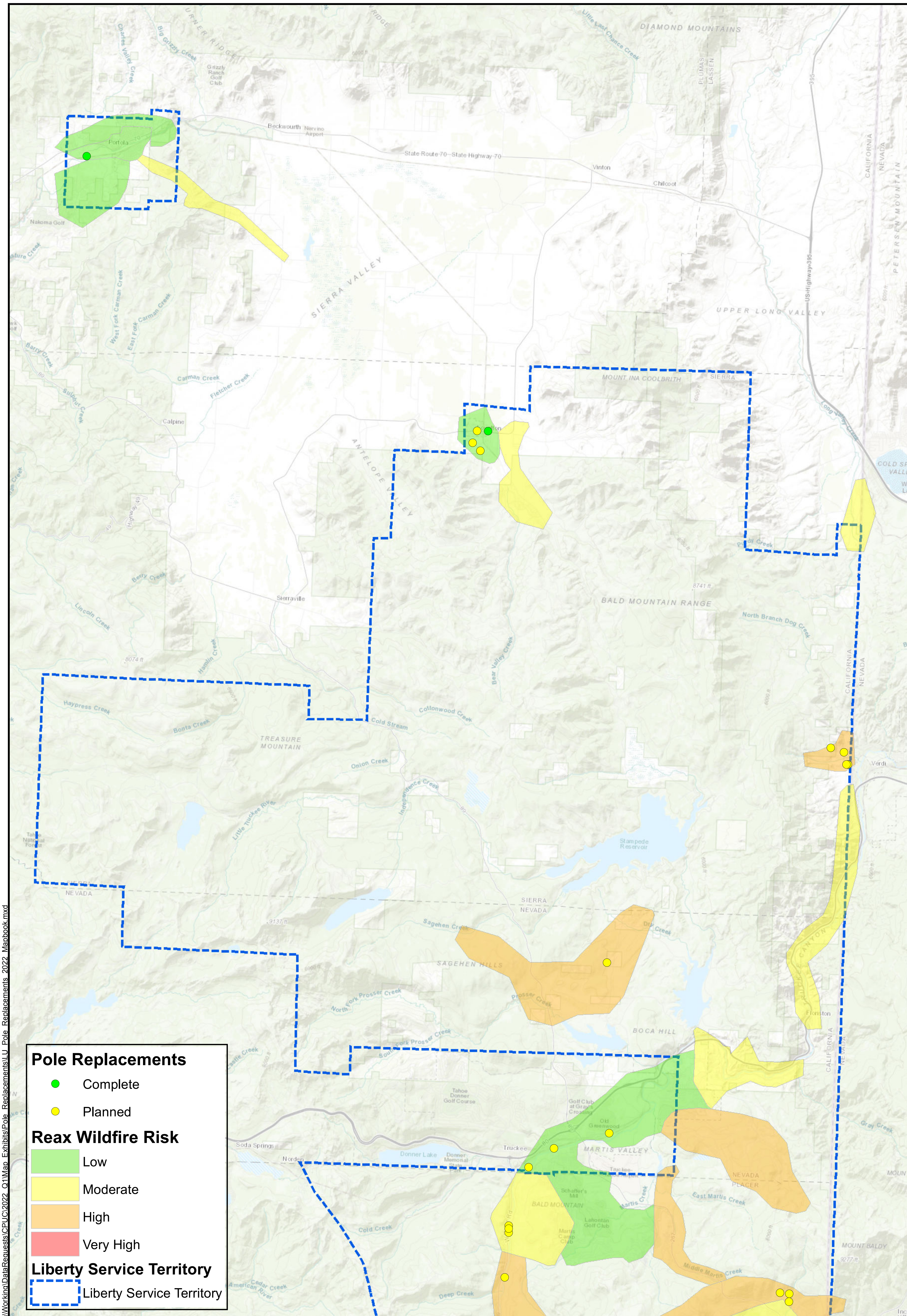

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701 National Ave
Tahoe Vista, CA 96148

Page 1 of 3
Pole Replacements
2022

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1 inch = 3 miles

Date: 4/26/2022

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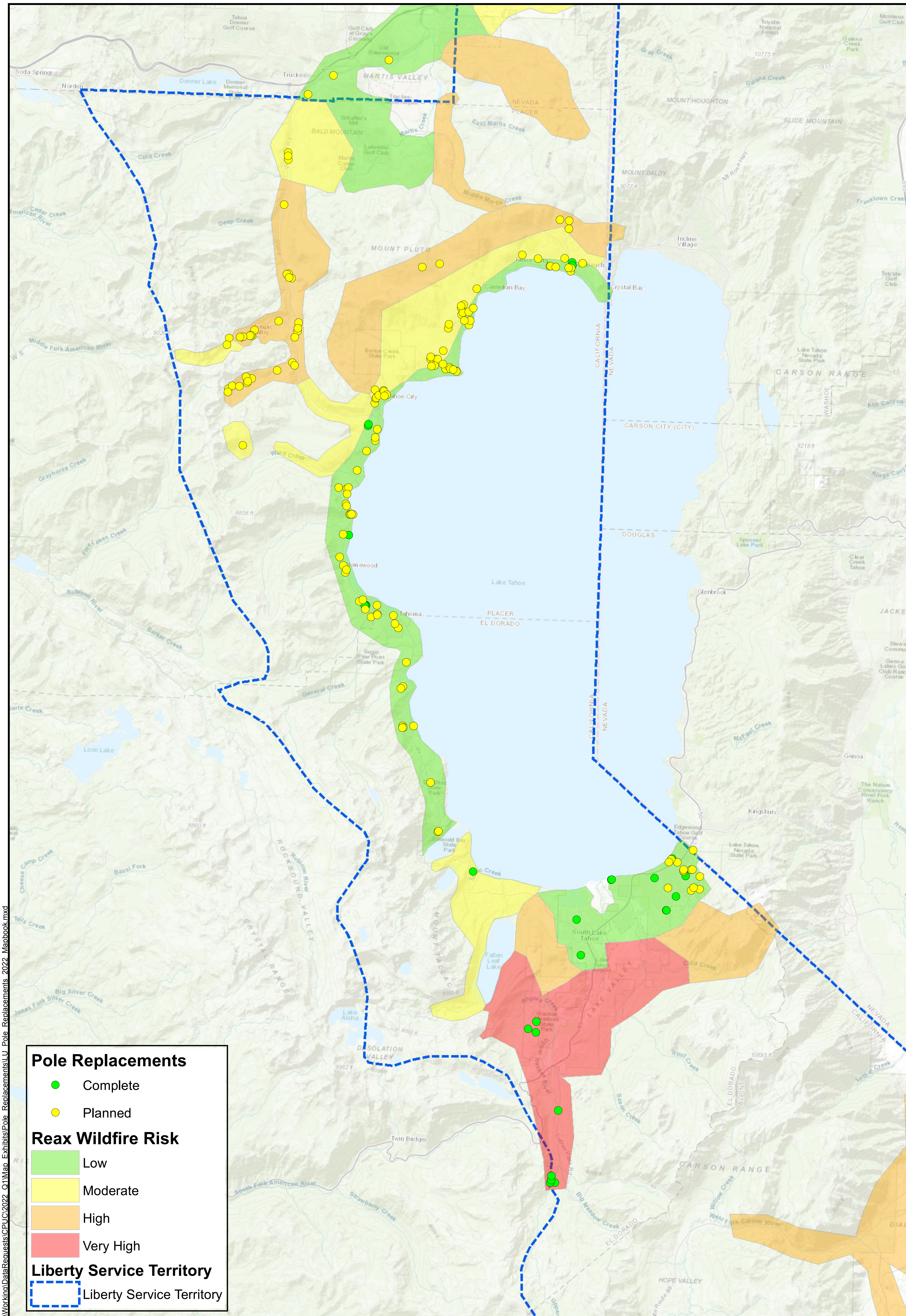

Liberty

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Pole Replacements
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1 inch = 3 miles

Date: 4/26/2022

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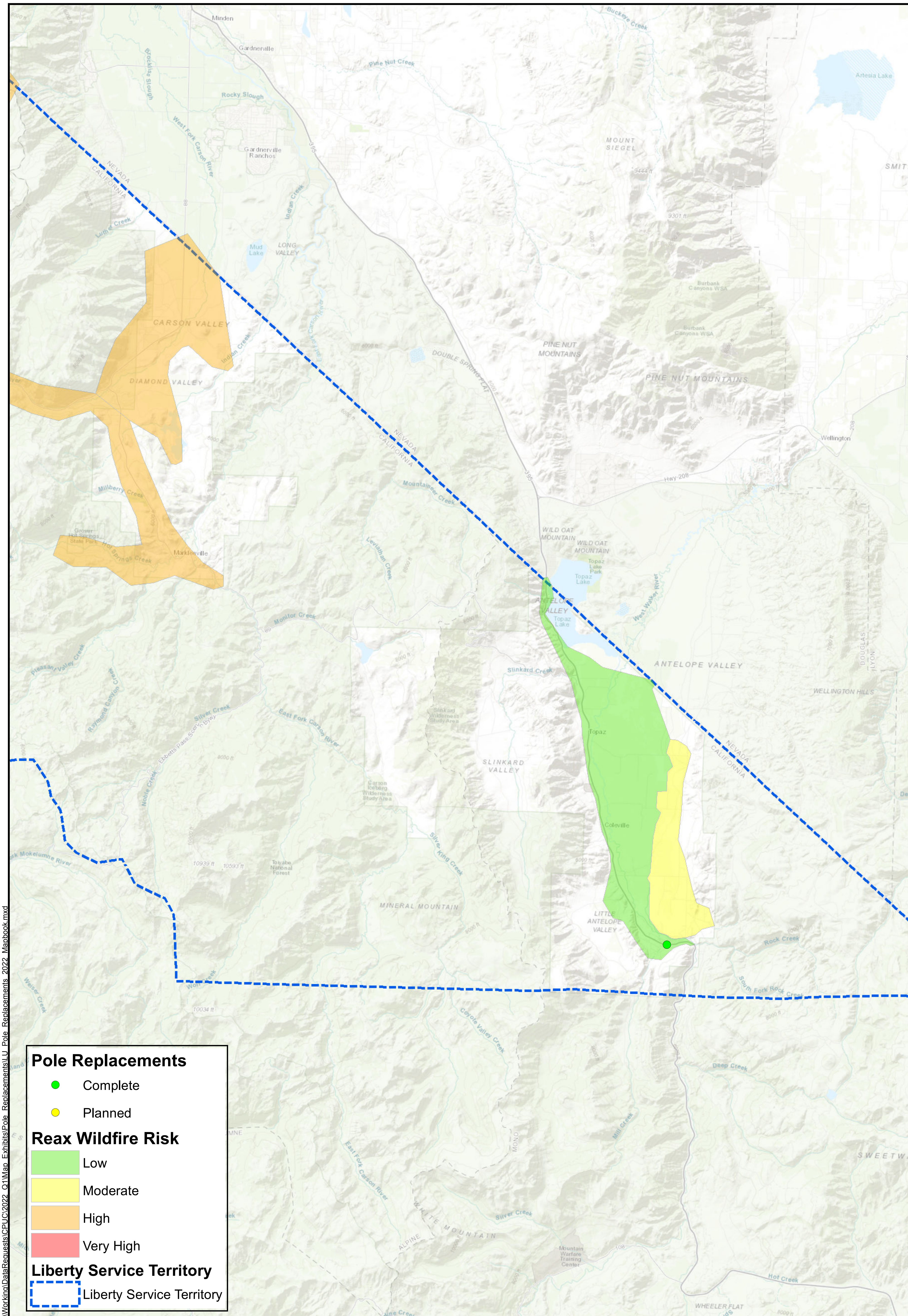

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Pole Replacements
2022

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1 inch = 3 miles

Date: 4/26/2022

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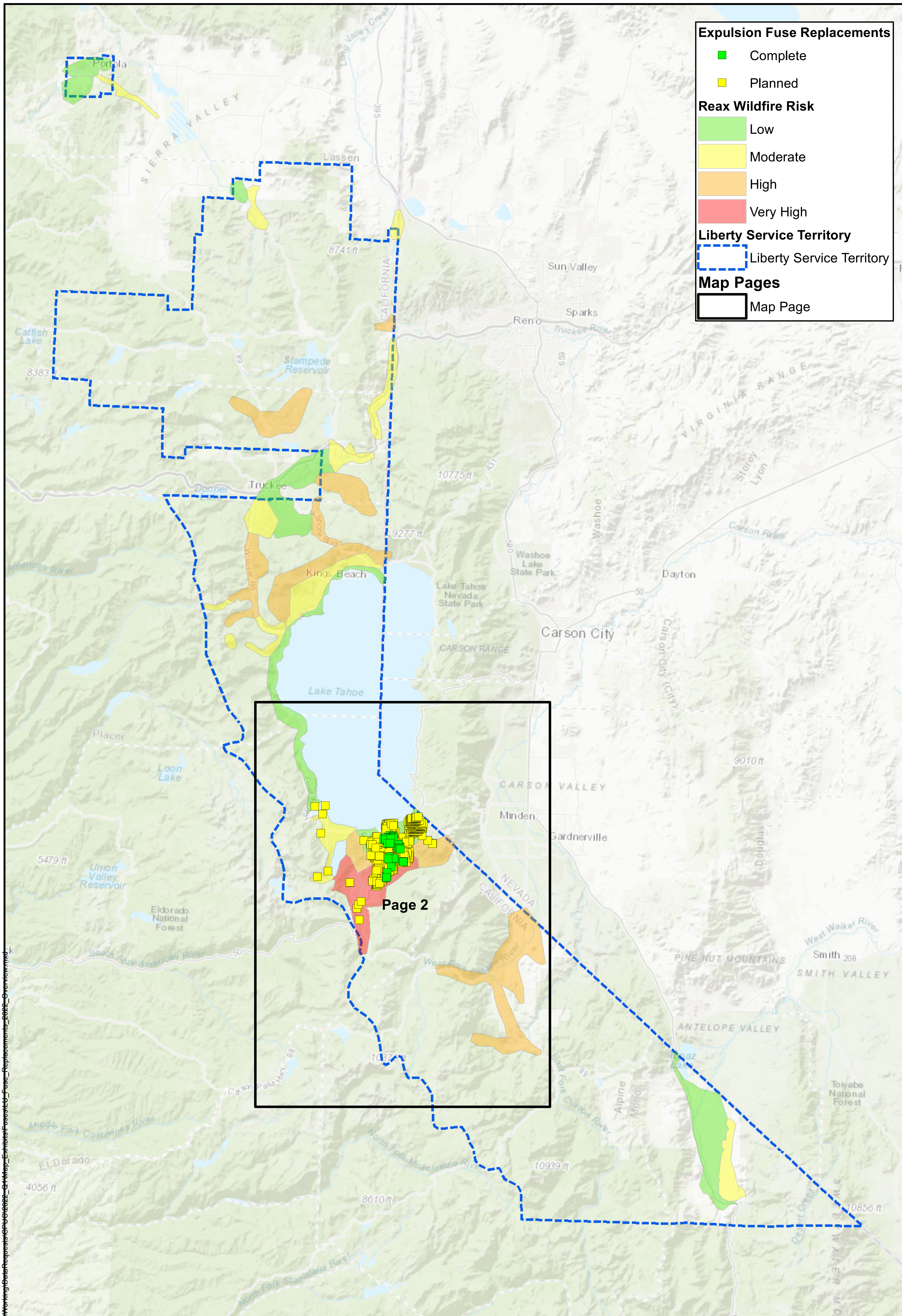

701 National Ave
Tahoe Vista, CA 96148

Overview Expulsion Fuse Replacements 2022

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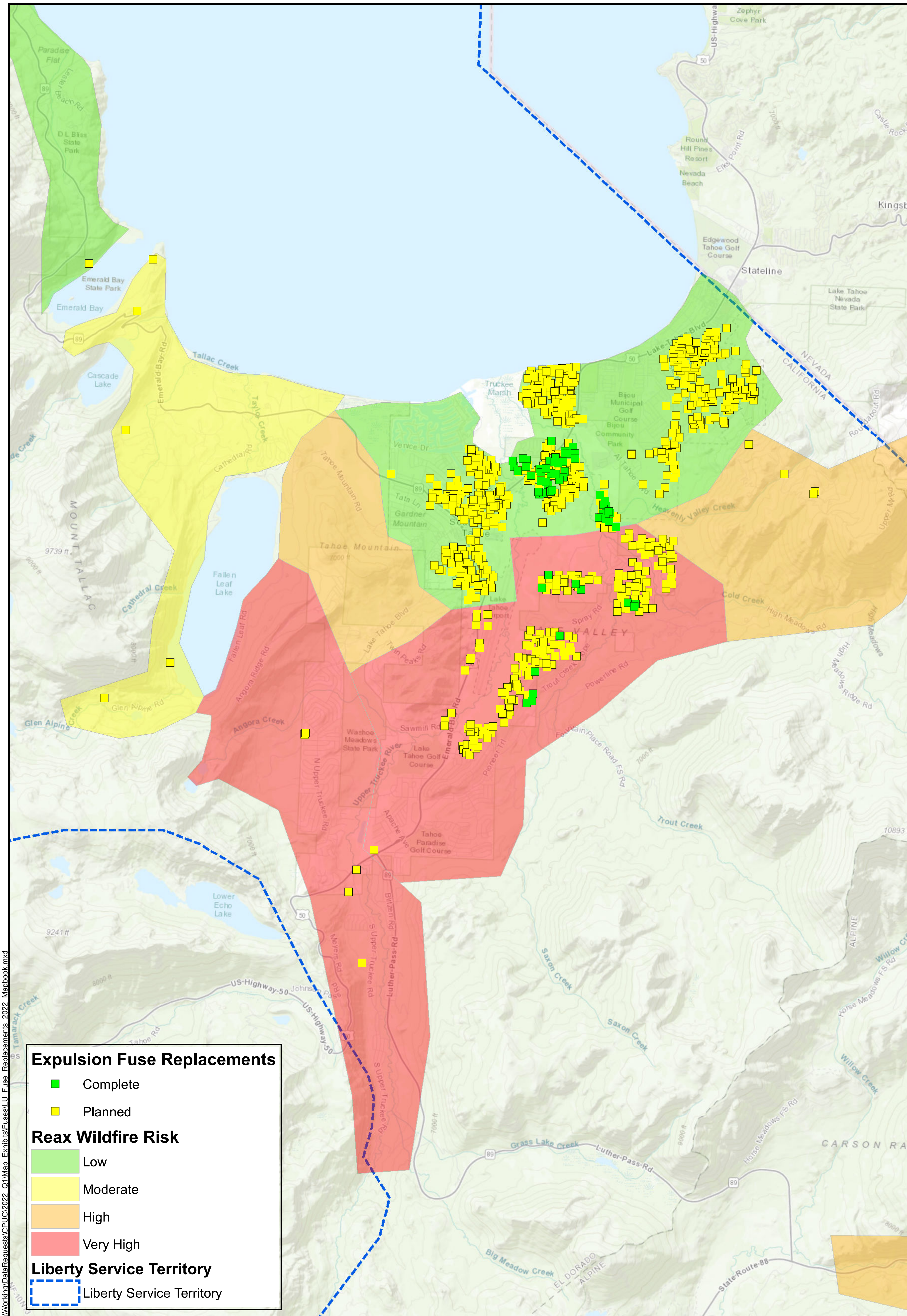
0 — 7 Miles	Date: 4/26/2022



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Liberty

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Page 1 of 1
Expulsion Fuse
Replacements 2022

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Feet

1 inch = 6,000 feet

Date: 4/26/2022

Attachment D

Joint IOU Covered Conductor Effectiveness Report

2022 WMP Update Progress Report

Effectiveness of Covered Conductor

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Issue

The rationale to support the selection of covered conductor as a preferred initiative to mitigate wildfire risk lacks consistency among the utilities, leading some utilities to potentially expedite covered conductor deployment without first demonstrating a full understanding of its long-term risk reduction and cost-effectiveness. The utilities' current covered conductor pilot efforts are limited in scope[1] and therefore fail to provide a full basis for understanding how covered conductor will perform in the field. Additionally, utilities justify covered conductor installation by alluding to reduced PSPS risk but fail to provide adequate comparison to other initiatives' ability to reduce PSPS risk.

Remedies

The utilities[2] must coordinate to develop a consistent approach to evaluating the long-term risk reduction and cost-effectiveness of covered conductor deployment, including: 1. The effectiveness of covered conductor in the field in comparison to alternative initiatives. 2. How covered conductor installation compares to other initiatives in its potential to reduce PSPS risk.

[1] Limited in terms of mileage installed, time elapsed since initial installation, or both. For example, SDG&E's pilot consisted of installing 1.9 miles of covered conductor, which has only been in place for one year.
[2] Here "utilities" refers to SDG&E and PG&E, SCE, PacifiCorp, BVES, and Liberty; although this may not be the case every time "utilities" is used throughout this progress report.

Response

The utilities have prepared a joint response to this Issue/Remedy.

Introduction

In the November 2021 Progress Report, the utilities outlined the approach, assumptions, and preliminary milestones to enable the utilities' to better discern the long-term risk reduction effectiveness of covered conductor to reduce the probability of ignition, assess its effectiveness compared to alternative initiatives, and assess its potential to reduce PSPS risk in comparison to other initiatives. In this report for the 2022 WMP Update, the utilities provide an update on their progress for each of the sub-workstreams, added efforts, and plans for 2022.

Overview

As explained in the November 2021 Progress Report, the utilities believe that long-term effectiveness of covered conductor and its ability to reduce wildfire risk and PSPS impacts (and, in comparison to alternatives) requires multiple sets of information that need to be compiled, assessed, and updated over time. Since the November 2021 Progress Report, the utilities have made progress on each of the following sub-workstreams:

- Benchmarking
- Testing / Studies
- Estimated Effectiveness
- Additional Recorded Effectiveness
- Alternative comparison
- Potential to Reduce PSPS risk
- Costs

The utilities have also initiated discussions with the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group (DRWG) to establish a peer-review process for estimating/measuring the effectiveness of covered conductor. The utilities have obtained additional information from benchmarking, the Phase 1 Testing Report, initial subject matter expert (SME) assessments of effectiveness of alternatives compared to covered conductor, an initial unit cost comparison, and have collected the utilities' estimated and recorded methods and results of covered conductor effectiveness. Each of these efforts are described further below. The information and assessments continue to indicate covered conductor effectiveness between approximately 60 to 90 percent in reducing the drivers of wildfire risk, consistent with past benchmarking, testing and utility estimates. The utilities plan to continue each sub-workstream in 2022 to obtain new test data, conduct further benchmarking, improve methods for estimating and measuring effectiveness, and further the alternative assessments and unit cost comparisons. Below, the utilities describe the progress made on each sub-workstream and steps planned to continue this effort in 2022.

Background

Covered conductor is a widely accepted term to distinguish from bare conductor. The term indicates that the installed system utilizes conductor manufactured with an internal semiconducting layer and external insulating UV resistant layers to provide incidental contact protection. Covered conductor is used in the U.S. in lieu of "insulated conductor," which is reserved for grounded overhead cable. Other utilities in the world use the terms "covered conductor," "insulated conductor," or "coated conductor" interchangeably. Covered conductor is a generic name for many sub-categories of conductor design and field construction arrangement. In the U.S., a few types of covered conductor are as follows:

- Tree wire
    - Term was widely used in the U.S. in 1970s
    - Associated with a simple one-layer insulated design
    - Used to indicate cross-arm construction
- Spacer cable
    - Associated with construction using trapezoidal insulated spacers and a high strength messenger line for suspending covered conductor
- Aerial bundled cable (ABC)
    - Tightly bundled insulated conductor, usually with a bare neutral conductor

The current type of covered conductor being installed in each of the utilities' service areas is an extruded multi-layer design of protective high-density or cross-linked polyethylene material. In this report, "covered conductor" refers generally to a system installed on cross-arms, in a spacer cable configuration, or as ABC. Table 1, below, provides a snapshot of the approximate amount and types of covered conductor installed in the utilities' service areas.

Table 1: Covered Conductor Type and Approximate Circuit Miles Deployed by Utility

Utility	First covered conductor installation (year)	Type of covered conductor installed	Approx. miles of covered conductor deployed through 2021	Notes
SCE	2018	Covered Conductor	2,900	Includes WCCP and Non-WCCP
	Installed Historically	Tree Wire	50	
	Installed Historically	ABC	64	
PG&E	CC end of 2017, beginning of 2018	Covered Conductor	883	Primary distribution overhead only
	TW installed historically	ABC	3	
SDG&E	2020	Covered Conductor	22	
		Tree Wire	2	
		Spacer Cable	6	
Liberty	2019	Covered Conductor	9	
		Spacer Cable	2	
Pacificorp	2007	Spacer Cable	53	
Bear Valley	2018	Covered Conductor	20	

Workstream Scope

The overall focus is on the long-term effectiveness of covered conductor to reduce wildfire risk and PSPS impacts in comparison to alternatives. The outcome of this workstream is not to determine the scope of covered conductor nor is this effort intended to compare system hardening decisions that utilities have made and will make. Instead, the outcome of this effort is intended to produce (and update over time) a consistent understanding of the effectiveness of covered conductor, in comparison with alternatives to mitigate wildfire risk at the driver level and to reduce PSPS impacts. Utilities can then use these improved sets of information in their decision making. As part of this effort, the utilities anticipate there will likely be lessons the utilities can learn from one another such as construction methods, engineering/planning, execution tactics, etc. that can help improve each utilities' deployment of covered conductor but this is not the focus of this workstream. Additionally, and as further described below, the costs of covered conductor deployment differ based on numerous factors including, for example, the utilities' covered conductor system design, types and amounts of structure/equipment replacements, topography, scale of deployment, resource availability and other operational constraints. This effort is not intended to compare nor contrast costs across all different variations and instead presents an initial high-level covered conductor capital cost per circuit mile comparison with descriptions of the factors that lead to higher or lower costs.

Benchmarking

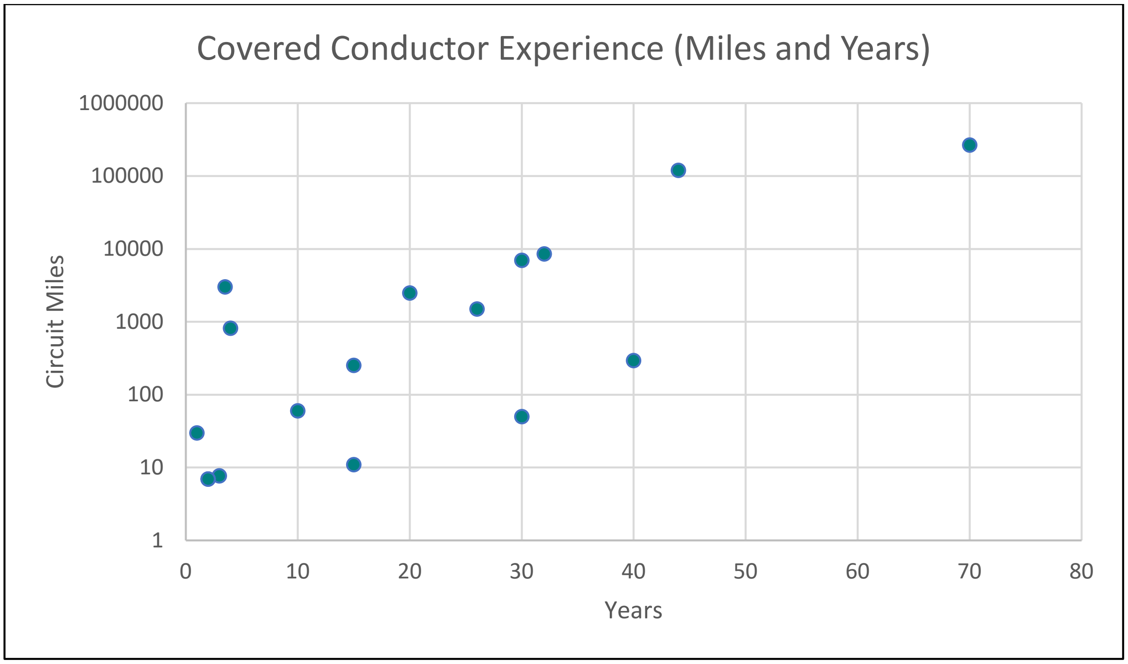
Each of the utilities' covered conductor programs have been informed by benchmarking. Benchmarking is a useful process to obtain insights, lessons learned, and continually improve performance. SCE, for example, previously researched covered conductor use in the U.S., Europe, Asia, and Australia. SCE benchmarked directly with 13 utilities abroad and in the U.S. and surveyed 36 utilities on covered conductor usage.[3] These efforts helped inform SCE's Wildfire Covered Conductor Program (WCCP). The utilities, as part of this joint working group, have conducted additional benchmarking. First, the utilities developed a survey consisting of 24 questions that focused on covered conductor usage, performance metrics, conductor applications, and system protection. The survey was then sent to approximately 150 to 200 utilities in the U.S. and abroad. To date, 19 utilities participated in the benchmarking survey[4] and are listed below.

1. American Electric Power
2. Ausnet Services
3. Bear Valley Electric Service, Inc.
4. Duke Energy
5. Essential Energy
6. Eversource Energy (CT)
7. Korean Electric Power Corporation
8. Liberty
9. National Grid
10. Pacific Gas and Electric Company
11. PacifiCorp
12. Portland General
13. Powercor
14. Puget Sound Energy
15. San Diego Gas & Electric
16. Southern California Edison
17. TasNetworks
18. Tokyo Electric Power Company
19. Xcel Energy

[3] See SCE's Covered Conductor Compendium that was included in the November 1, 2021 Progress Report.
[4] See Covered Conductor Survey Results in Appendix A.

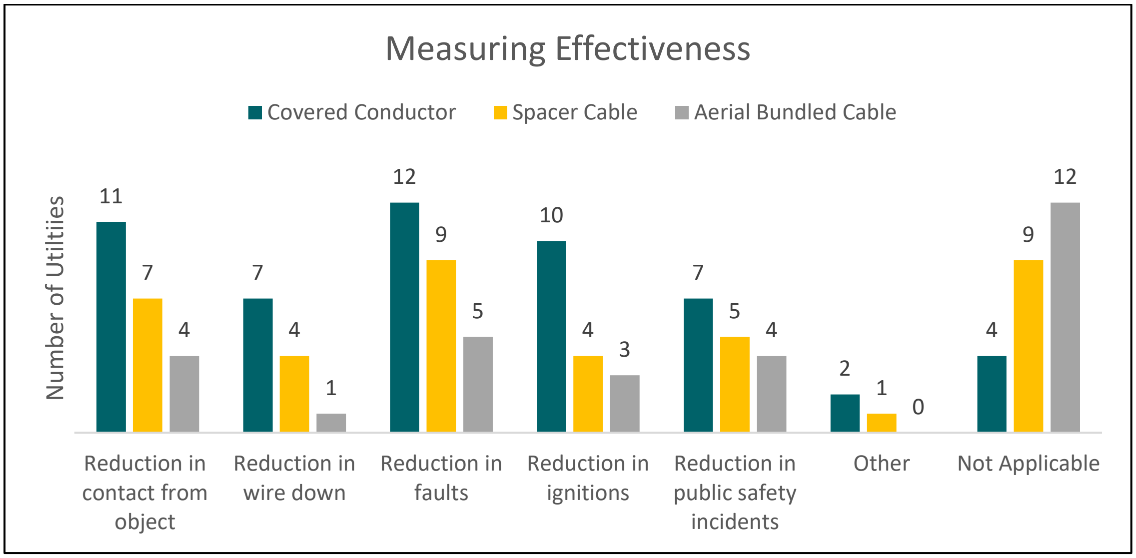
Approximately 90% of participants indicated the usage of bare conductor and covered conductor in their distribution systems. Respondents using spacer cable and aerial bundled cable were at 58% and 47%, respectively. Note that while covered conductor designs varied among the utilities, the majority (63%) of utilities use the three-layer jacket design. There was also a wide range of experience among respondents in terms of the number of years and miles installed, as shown in Figure 1.

Figure 1: Covered Conductor (Open-crossarm and Spacer) Experience Among Respondents



Drivers for covered conductor deployment can vary by utility. Typical drivers include wildfire mitigation, reliability improvements, or reduction in public safety risk for contact with downed conductors. The utilities' performance metrics will differ depending on their associated drivers. The majority of utilities base the covered conductor's effectiveness in its ability to reduce faults and ignitions from contact-from-objects (CFO). These metrics are related to reliability and wildfire mitigation. Some utilities also measure the reduction in wire downs and public safety incidents to measure the covered conductor's effectiveness, which can be connected to public safety risk or ignition drivers. Figure 2 illustrates the number of utilities using each metric to monitor the effectiveness of covered conductor, spacer cable, and aerial bundled cable.

Figure 2: Covered Conductor Performance Metrics In Use by Utilities



While most utilities do not differentiate outages or ignitions between bare conductor and covered conductor, 84% of respondents reported that the use of covered conductor has reduced faults. Furthermore, 53% of respondents reported that covered conductor has reduced ignitions or ignition drivers. The remaining 47% of utilities do not track ignition data, had no prior ignitions, or do not have covered conductor in their system.

Approximately 80% of utilities reported undergrounding as an alternative to covered conductor. About 40% of utilities consider spacer cable while approximately 25% consider aerial bundled cable as alternatives to covered conductor. Typically, spacer cable is utilized in heavily-forested areas or areas with clearance concerns. Aerial bundled cable is normally indicated as used in heavily forested areas. Only 5% of utilities indicated the use of other alternatives, such as line removal/relocation, animal guard, fast isolation device, remote grid, customer buyout, and vegetation management.

In terms of fault detection, most utilities utilize traditional overcurrent protection. The same protection system that is used for bare conductors. Other existing fault detection methodologies include SCADA connected devices, smart meters, and high impedance fault detection. Utilities are also exploring a multitude of different technologies, including early fault detection (EFD), distribution fault anticipation (DFA), open phase detection (OPD), sensitive ground fault, rapid earth fault current limiter (REFCL), downed conductor detection, etc.

Overall, the benchmarking survey provides a high-level overview of each utilities' covered conductor deployment and performance metrics. In 2022, the California Investor-Owned Utilities (IOUs) plan to conduct further deep dives with some respondents to gain a greater understanding of their covered conductor effectiveness, recorded data and methods they use to measure effectiveness, alternatives and new technology that have been evaluated, and their system hardening decision-making processes. The utilities will provide an update on these efforts in their 2023-2025 WMPs.

Testing

Testing workstream objectives are to evaluate, through physical testing, the performance of covered conductors as compared to bare conductors for historically documented failure modes. As an example, testing covered conductor performance in preventing incidental contacts that cause phase-to-phase and phase-to-ground faults caused by vegetation, conductor slapping, wildlife, and metallic balloons.[5] To meet this objective, PG&E, SDG&E, and SCE collaborated on conducting additional research and testing of covered conductor. This effort, now joined by PacifiCorp, BVES and Liberty, has two phases. The first phase, which is now complete, had objectives to identify failure modes for covered conductors, document a utilities' consensus Failure Modes and Effects Analysis (FMEA) for covered conductors, and to collect all previously conducted testing on covered conductor performance that informs on the performance of covered conductor for identified failure modes. Lastly, to perform comparison between covered versus bare conductor performance for failure modes tested. PG&E contracted with Exponent, Inc. (Exponent) to develop a report for Phase 1, which was completed in December 2021, summarized below, and attached as Appendix B to this update. The Phase 1 study was led by Exponent and consisted of a literature review, discussions with SMEs, a failure mode identification workshop, and a gap analysis comparing expected failure modes to currently available test and field data. The outcome of the Phase 1 report identified gaps in previous testing and is informing the scope of laboratory testing that is currently being planned for in the ongoing Phase 2 step of this sub-workstream. As discussed below, SCE, PG&E, and SDG&E are proceeding with testing.

The literature review shows that covered conductors are a mature technology (in use since the 1970s) and have the potential to mitigate several safety, reliability, and wildfire risks inherent to bare conductors. This is due to the reduced vulnerability to arcing/faults afforded by the multi-layered polymeric insulating sheath material. Field experience from around the world, including North America, South America, Europe, Asia, and Australia, consistently shows improvements in reliability, decreases in public safety incidents, and decreases in wildfire-related events that correlate with increased conversion to covered conductor. The Phase 1 report includes data from several utilities that show a reduction of faults, increased reliability, and/or improvements in public safety metrics since the utilities began implementing covered conductor.

While high-level, field-experience-based evidence of covered conductor effectiveness is plentiful, relatively few lab-based studies exist that address specific failure modes or quantify risk reduction relative to bare conductors. A high-level failure mode identification workshop was conducted to identify operative failure modes relevant to overhead distribution systems for both bare and covered conductors. The workshop included SMEs from the six California IOUs and Exponent and identified hazards and failure modes applicable to bare and covered conductors. In total, 10 hazards and 55 unique failure mode / hazard scenario combinations were identified through the failure mode workshop. Of the 10 hazards that affect bare conductors, covered conductors have the potential to mitigate six hazards. Mitigated hazards include tree/vegetation contact, wind-induced contact (such as conductor slapping), third-party damage, animal-related damage, public/worker impact, and moisture. The report includes a risk reduction assessment of the failure modes that affect both bare and covered conductors. The report also summarizes failure modes mitigated by covered conductor. A total of 17 failure modes largely mitigated through the use of covered conductor were identified through the workshop exercise. The common theme among these failure modes is that they are created through contact with third-party objects, vegetation, or other conductors that create phase-to-ground or phase-to-phase faults. The primary failure mode of bare conductors is arcing due to external contact. Laboratory studies and field experience have shown that arcing due to external contact was largely mitigated with covered conductors. Therefore, a corresponding reduction in ignition potential would be expected. The report also summarizes failure modes unique to covered conductor. Several covered-conductor-specific failure modes exist that require operators to consider additional personnel training,

[5] See SCE's Covered Conductor Compendium that was included in the November 1, 2021 Progress Report.

augmented installation practices, and adoption of new mitigation strategies (e.g., additional lightning arrestors, conductor washing programs, etc.). For some failure modes, the report recommends further testing to bolster industry knowledge and to enable more effective risk assessment.

SCE, PG&E and SDG&E are pursuing testing based on the results of the Phase 1 report and SME input. SCE established a test plan for both 17 kV[6] and 35 kV covered conductor designs and expects to conduct approximately 35 testing scenarios that cover various contact-from-object, system strength, flammability, and water ingress scenarios. PG&E is in process of developing a complementary test plan to ensure coverage of failure modes and additional covered conductor types that may not be included in the SCE test plan. SDG&E is assessing conducting, for example, environmental, service life, UV exposure, degradation and mechanical strength tests. The utilities are collaborating on the testing plans to ensure the gaps identified in the Phase 1 report are covered and SME input is considered.[7] SCE began testing on February 1 , 2022 and anticipates its testing and review process to extend for several months. SDG&E and PG&E timelines have not been finalized but are anticipating testing to start around Q2 to Q3 2022. The utilities will collaboratively review and assess the results of the tests. After the test results are reviewed and any issues are addressed (e.g., additional tests), the utilities will prepare a report (or reports in phases as testing is completed) and make the report(s) available. The test results are anticipated to further inform effectiveness of covered conductor and potentially identify any needed changes in design and construction standards to ensure failure modes are further limited by the use of covered conductor. Beyond the testing process, in 2022, the utilities will continue to collaborate on methods to quantify risk reduction of covered conductor relative to bare conductors taking into account the testing results and will establish any next steps for this sub-workstream based on the results of the testing. The utilities will provide an update on these efforts in their 2023-2025 WMPs.

Estimated Effectiveness

Each utility's covered conductor programs are different due to factors such as location, terrain, and existing overhead facilities. Similarly, the utilities are at different phases of installing covered conductor as some have just started deployment while others have deployed hundreds to thousands of miles of covered conductor. These features, amongst others, result in data, calculations, and methods of estimating effectiveness that are different. As such, the utilities have been working on understanding differences and discussing methods for better comparability. While the utilities may differ in their covered conductor approach, the utilities each estimate that covered conductor will reduce wildfire risk. The utilities' estimated covered conductor effectiveness values range from approximately 60 to 90 percent at reducing outages/ignitions and/or the drivers of wildfire risk. Below, the utilities describe their data, analyses, and methods used to estimate the effectiveness of covered conductor to mitigate outages/ignitions and/or the drivers of wildfire risk and present their estimated effectiveness values. Collectively, the utilities summarize next steps to improve consistency of data, calculations and methods.

Covered Conductor Estimated Effectiveness

SCE

SCE's WCCP consists of replacing bare conductor with covered conductor, the installation fire-resistant poles (FRPs) where applicable, wildlife covers (animal safe construction), lighting arresters, and vibration

[6] SCE's 17 kV covered conductor design is the same as other utilities' 15 kV design. Through testing, SCE determined that the 15 kV design can withstand voltages below 17 kV so has named this covered conductor design 17 kV for operational purposes.
[7] SCE, PG&E, and SDG&E are also collaborating on potential cost sharing.

dampers below 3,000 feet. These activities are accounted for when determining the overall mitigation effectiveness of SCE's WCCP. To determine the mitigation effectiveness of WCCP, SCE evaluated the ability for covered conductor and FRPs to address each ignition risk driver. SME judgment was used to determine the mitigation effectiveness of covered conductor; this judgment was informed by benchmarking, analysis, and testing. The following tables explain the reasoning behind the effectiveness values. Table 2, includes only the covered conductor values and not the combined covered conductor and FRP values used in SCE's risk reduction calculation. Table 3 includes only the FRP mitigation effectiveness values. Additionally, mitigation effectiveness values at 0% or that were not applicable were omitted from both tables.

Table 2: SCE Covered Conductor Mitigation Effectiveness Estimate

Driver		Mitigation Effectiveness	Reasoning
D-CFO	Vegetation contact-Distribution	60%	SCE conducted analysis that involved establishing four vegetation sub-drivers based on SCE's experience with vegetation contact. The four sub-drivers are: Heavy Contact (Tree), Heavy Contact (Limb), Light Contact (Frond/Branch), Light Contact (Grow In). SCE analyzed historical vegetation fault data from 2015-2018 and determined that percentage of occurrence between all four sub-drivers. • Heavy Contact (Tree): 30% • Heavy Contact (Limb): 22% • Light Contact (Frond/Branch): 43% • Light Contact (Grow In): 5% SCE testing supported that covered conductor will be 99% effective against both Light Contact drivers, which accounts for 1% of the line potentially being uninsulated at connection points or dead-ends. Additionally, SCE also determined that covered conductor will not be effective against Heavy Contact (Tree) due to being unable to mechanically support the weight of a tree. Covered conductor was determined to be 50% effective against limb contact, conservatively assuming that the limb will exceed the conductor's strength 50% of the time. The overall mitigation effectiveness value for vegetation is based on the weighted average of all four sub-driver and was calculated to be 60%.
D-CFO	Animal contact-Distribution	65%	SCE conducted analysis that involved establishing animal contact sub-drivers in terms of equipment affected. These Animal Contact sub-drivers include Conductor/Wire, Fuse/BLF/Cutout, Terminations,

Driver		Mitigation Effectiveness	Reasoning
			Transformer, etc. The percent of animal contact faults were calculated per sub-driver using 2015-2020 data. Next, SCE used SME knowledge to establish the percent of wildlife covers existing in the system for the applicable sub-driver. Lastly, SCE assigned a preliminary mitigation effectiveness based on SME judgement per sub-driver. Covered conductor is considered 100% effective for Conductor/Wire Animal contact based on testing. Other equipment with associated wildlife covers were assigned a 90% effectiveness to account for the wildlife cover installation required during WCCP. The preliminary mitigation effectiveness was multiplied by the percent of wildlife covers not existing in the system to adjust for the possibility that pre-WCCP structures already have wildlife covers. The weighted average of this adjusted mitigation effectiveness was calculated to be 65%.
D-CFO	Balloon contact-Distribution	99%	Covered conductor is estimated to be 99% effective against contact with metallic balloons. This is supported by testing and accounts for approximately 1% of the line potentially being uninsulated at connection points or dead-ends.
D-CFO	Vehicle contact-Distribution	50%	SCE analyzed the composition of historical wire downs from vehicle collisions and found that nearly all ignitions from a vehicle collision are caused by conductor contact. SCE testing established the covered conductor is effective against conductor-to-conductor contact. However, there is uncertainty regarding the effectiveness of covered conductor during a wire down due to exposed conductor at the dead-end or break-point. To account for this uncertainty, a mitigation effectiveness of 50% was assumed.
D-CFO	Other contact-from-object - Distribution	77%	Analysis found that foreign material accounts for 77% of the “Unspecified” driver, while Ice/Snow accounts for the other 23%. While covered conductor is effective against foreign materials, it is not effective against ice/snow.
D-CFO	Connection device damage or failure - Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged hardware. Some hardware used in new installation will also be improved technology.
D-CFO	Unknown contact - Distribution	77%	Weighted average of vegetation contact, animal contact, balloon contact, and other contact.

Driver		Mitigation Effectiveness	Reasoning
D-EFF[8]	Splice damage or failure — Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged hardware. Some hardware used in new installation will also be improved technology.
D-EFF	Crossarm damage or failure - Distribution	50%	Covered conductor is estimated to be 50% effective against crossarm failure. Reconductoring with covered conductor will facilitate the replacement of aged crossarms. Additionally, testing illustrated that covered conductor significantly reduced leakage current on the crossarm, reducing the occurrence of damage due to electrical tracking.
D-EFF	Insulator damage or failure- Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged insulators.
D-EFF	Wire-to-wire contact / contamination- Distribution	99%	Covered conductor is estimated to be 99% effective against wire-to-wire contact. This is supported by testing and accounts for approximately 1% of the line potentially being uninsulated at connection points or dead-ends.
D-EFF	Conductor damage or failure — Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged conductor. Additionally, conductor failure due to faults will also be reduced because: (1) covered conductor will prevent contact-from-object faults from occurring and (2) the covered conductor will have a larger short circuit duty.
D-EFF	Insulator and brushing damage or failure - Distribution	90%	Assumption that infrastructure replacement will lead to 90% mitigation effectiveness. Reconductoring with covered conductor will facilitate the replacement of aged insulators.

Table 3: SCE Fire Resistant Pole Mitigation Effectiveness

Driver		Mitigation Effectiveness	Reasoning
D-EFF	Crossarm damage or failure - Distribution	50%	Replacing existing poles with FRPs will facilitate the replacement of aged wood crossarms with composite crossarms. Additionally, fire-resistant composite poles significantly reduce leakage

[8] EFF represents Equipment / Facility Failure

Driver		Mitigation Effectiveness	Reasoning
			current on the crossarm, reducing the occurrence of damage due to electrical tracking. The improved crossarm design and reduction of leakage current accounts for the 50% effectiveness against crossarm damage or failure.
D-EFF	Conductor damage or failure — Distribution	5%	Replacing poles with FRPs will facilitate the replacement of aged equipment.
D-EFF	Fuse damage or failure - Distribution	5%	Replacing poles with FRPs will facilitate the replacement of aged equipment. The new fuses used will be improved technology.
D-EFF	Switch damage or failure- Distribution	5%	Replacing poles with FRPs will facilitate the replacement of aged equipment. The new switches may be improved technology.
D-EFF	Insulator and bushing damage or failure - Distribution	50%	Replacing poles with FRPs will facilitate the replacement of aged equipment.
D-EFF	Transformer damage or failure - Distribution	50%	Replacing poles with FRPs will facilitate the replacement of aged equipment.

PG&E

PG&E's covered conductor program consists of primary and secondary conductor replacement with covered conductor along with pole replacements, replacement of non-exempt equipment, replacement of overhead distribution line transformers with transformers with FR3 insulating fluid, framing and animal protection upgrades, and vegetation clearing which makes up the entire Overhead Hardening program. PG&E understands the focus of this issue to be centered on covered conductor, however, PG&E's efforts to estimate effectiveness extend to include all elements of its Overhead Hardening program as PG&E considers this approach more complete.

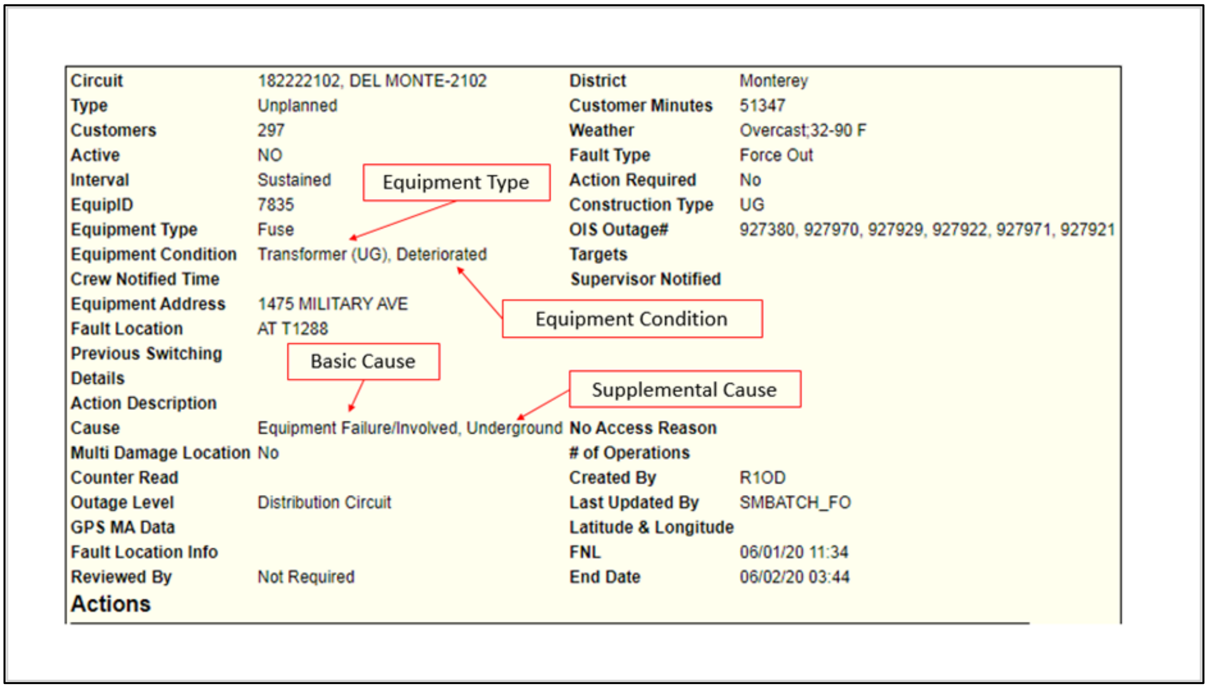
Determining whether a specific event could result in an ignition depends upon a wide variety of factors, including the nature of the event itself and prevailing environmental conditions (e.g., weather, ground moisture level, time of year). As PG&E does not have complete information to make this determination for each event, estimating overhead hardening effectiveness relies upon the following proxy, outlined below, to derive its estimates. Most distribution outages (momentary and sustained) typically involve a fault condition. Thus, for purposes of estimating overhead hardening effectiveness, it is assumed that all distribution outages could potentially result in an ignition, regardless of other prevailing conditions. This approach aligns with what has been previously stated in PG&E's 2020 WMP as well as its 2020 RAMP filing.

With the above assumption, PG&E took the following approach to estimate a general effectiveness factor for overhead hardening:

1. SMEs identified 4,336 distinct outages by using all known combinations of basic cause, supplemental cause, equipment type and equipment condition from the distribution outage database as show in Figure 3 below. Whenever an outage is reported, an operator fills in different fields that provide information about the outage, through SME evaluation, it was

decided that the combination of the four fields aforementioned provide an appropriate distinction of different outage types.

Figure 3: PG&E Distribution Outage Database Record



Circuit	182222102, DEL MONTE-2102	District	Monterey
Type	Unplanned	Customer Minutes	51347
Customers	297	Weather	Overcast;32-90 F
Active	NO	Fault Type	Force Out
Interval	Sustained	Action Required	No
EquipID	7835	Construction Type	UG
Equipment Type	Fuse	OIS Outage#	927380, 927970, 927929, 927922, 927971, 927921
Equipment Condition	Transformer (UG), Deteriorated	Targets	
Crew Notified Time		Supervisor Notified	
Equipment Address	1475 MILITARY AVE		
Fault Location	AT T1288		
Previous Switching Details			
Action Description			
Cause	Equipment Failure/Involved, Underground	No Access Reason	
Multi Damage Location	No	# of Operations	
Counter Read		Created By	R1OD
Outage Level	Distribution Circuit	Last Updated By	SMBATCH_FO
GPS MA Data		Latitude & Longitude	
Fault Location Info		FNL	06/01/20 11:34
Reviewed By	Not Required	End Date	06/02/20 03:44
Actions			

2. SMEs identified whether overhead hardening would eliminate, reduce significantly, reduce moderately, reduce minimally, or will not have an effect on the likelihood of a certain type of outage occurring leading to an ignition when an asset has been hardened. From this classification the following qualitative categorization was performed:

    - All = Eliminates likelihood of a certain type of outage occurring resulting in an ignition
    - High = Reduces likelihood significantly of a certain type of outage occurring resulting in an ignition
    - Medium = Reduces likelihood moderately of a certain type of outage occurring resulting in an ignition
    - Low = Reduces likelihood minimally of a certain type of outage occurring resulting in an ignition
    - None = Will not have an effect on likelihood of a certain type of outage occurring resulting in an ignition

3. Each of qualitative categories were assigned a quantitative value, which measured the likelihood of outage reduction:
    - All = 90%
    - High = 70%
    - Medium = 40%
    - Low = 20%

- None = 0%

4. The above criteria were applied to historical outages, this resulted in likelihood of outage reduction for each outage.
5. Outages were classified by drivers, the outage drivers identified are: Animal, D-Line Equipment Failure, Human Performance, Natural Hazard, Other, Other PG&E Assets or Processes, Physical Threat, RIM, Third Party, Vegetation. The Wildfire Mitigation driver is excluded as this captures all PSPS triggered outages.
6. The final step in preparing the data was to add meteorology data that provides historical wind events times during the analyzed period 2015-2019, as well as weather signal data to allow for further analysis with meteorology experts.
7. A Pivot table is then created to aggregate Outages in HFTD that occurred during acute wind events days, this is understood to be the time where the equipment would be most stressed by the environment as well as the area where Overhead Hardening is being conducted. The aggregation is done at the outage driver level

The results from the analysis detailed in the steps above are interpreted as Overhead Hardening having an effectiveness of approximately 63% for sections where Overhead Hardening has been completed. Therefore, a section of a line that has been hardened is approximately 63% less likely to have an outage of any type. Similarly, a section of a line that has been hardened is approximately 63% less likely to have an outage of each of the drivers. Table 4 provides a summary of the results from the analysis.

Table 4: PG&E Covered Conductor Mitigation Effectiveness Estimate

Driver	Count of Incident ID	Average of Overhead Hardening Effectiveness Percentage
Animal	36	76%
D-Line Equipment Failure	179	71%
Human Performance	3	0%
Natural Hazard	285	35%
Other	256	90%
Other PG&E Assets or Processes	15	47%
Third Party	20	62%
Vegetation	204	63%
Grand Total	**998**	**63%**

SDG&E

SDG&E initially began to examine covered conductor from a personnel safety and reliability standpoint. The three-layered construction showed prospective reduction of injuries to people in the event of an energized wire-down in which the wire contacted a person and/or also might reduce the step potential to people in the vicinity. Outages that result from light momentary contacts (e.g., mylar balloons, birds, and palm fronds) also have shown the potential to be reduced. In late 2018, focus was shifted towards using covered conductor as an alternative to SDG&E's traditional overhead hardening program with the primary focus of reducing utility-caused ignitions.

SME's conducted research on the history and use of covered conductor in the industry. Additionally, the SMEs reached out to utilities on the East Coast and internationally to receive their feedback of the effectiveness and work methods for installation purposes.

In addition to other studies/tests that have been and will be performed by SCE and PG&E, as described in the Testing section, SDG&E will have a third party evaluate the likelihood and effect specific to conductors clashing at various wind speeds. Accelerated aging studies will also be performed to mimic a 40-year service life; after which, the samples will be subjected to tests designed to understand the potential for both mechanical degradation, as well as a reduction in the dielectric strength of the covering. These tests will be performed in accordance with ASTM or other industry recognized standards.

In order to quantify the risk reduction of wildfires that would be achieved by covered conductor, SDG&E evaluated 80 events that resulted in ignitions. SMEs weighed in on the likelihood that covered conductor installation would prevent an ignition for the particular type of outage depending on the severity of the incident. As seen in Table 5, the result is a reduction in ignitions from 80 to 28.4, and a resulting effectiveness estimate of 64.5%.

Table 5: SDG&E Covered Conductor Mitigation Effectiveness Estimate

Fault/Ignition Cause	Number of Ignitions	SME Effectiveness	Post-Mitigation Ignitions
Animal contact	5	90%	0.5
Balloon contact	8	90%	0.8
Vegetation contact	10	90%	1.0
Vehicle contact	14	20%	11.2
Other contact	4	10%	3.6
Other	2	10%	1.8
Equipment - All	34	80%	6.8
Unknown	3	10%	2.7

Fault/Ignition Cause	Number of Ignitions	SME Effectiveness	Post-Mitigation Ignitions
Total	**80**	**64.5%**	**28.4**

PacifiCorp

PacifiCorp has some experience with installing a spacer cable system, which primarily includes covered conductor, a structural member (messenger), and specialized attachment brackets. The company pursued this design due to historical experience with elevated outage count from trees, limbs, and incidental contact (resulting in grow in) throughout its service territory. Additionally, access conditions on some of its circuits are extremely difficult in certain times of the year, and those circuits also tend to have elevated outage rates. For the above-mentioned reasons, when siting its spacer cable pilot projects, PacifiCorp tended to focus its deployment on circuit-segments that had above average vegetation and/or animal outage rates in conjunction with difficult access.

Spacer cable systems employ an engineered weak-link system where covered conductors are in a spaced bundle configuration. The bundle is supported by a high-strength tensioned cable which has shown to be able to support the cables even when the system is under extreme stress.[9] This system is secured to poles primarily with fixed or flex tangent brackets, in which the messenger is the only connected conductor. The covered conductors are not tensioned (nor are they structural members) and instead are held together with spacers attached to a tensioned messenger and placed approximately 30-feet apart. PacifiCorp's spacer cable systems are currently installed using components rated at or above 35 kV, where the only deviation is in the covered conductor itself, whereas it uses two voltage classes; 15 kV for energized voltages of 12.47 kV and below and 35 kV for energized voltages of 20.8 kV to 34.5 kV.

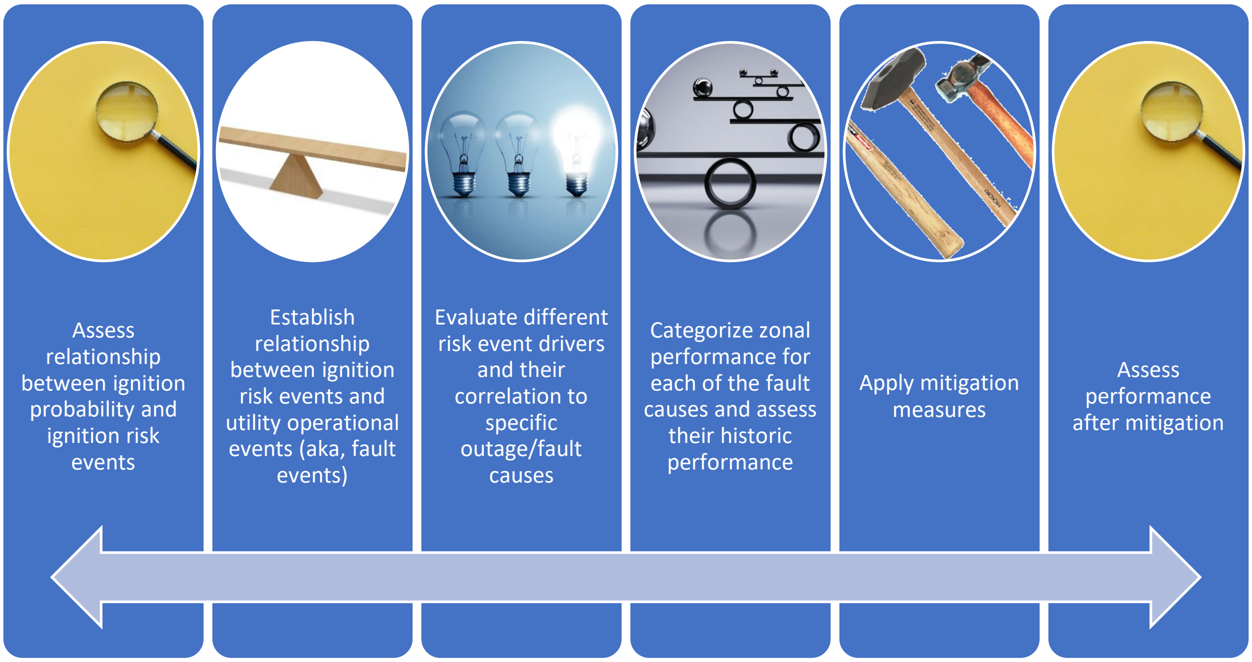
Originally contemplated as a reliability improvement tool, PacifiCorp has now moved to leveraging spacer cable as a wildfire mitigation tool; a natural progression given the similarities in risk drivers such as contract-from-object or damage from vegetation. In their original installations, reliability improvement was the driver, but because of the newness of the technology it was trialed in several different environments with differing installation approaches; the first was focused on contact-from-object/animals and subsequently two of them were focused on contact-from-object/vegetation, one in a coastal environment and another in a mountainous environment, which was followed by projects heavily targeting mitigation of contact-from-object as well as blow-in (and other incidental vegetation); the projects formed the basis for targeting covered conductor (specifically spacer cable) as a mitigation measure for ignition risk drivers.

PacifiCorp's process for evaluating ignition risk drivers, mitigation measures and effectiveness of measures (in order to long term calculate risk spend efficiency) is detailed below.

The company prepared a mapping exercise to evaluate which risks could be addressed with what alternatives, recognizing that covered conductor and a variety of other measures might all be valid approaches. As a starting point, the company evaluated its outage data to align against risk event drivers and correlating against mitigation alternatives. This process is shown graphically in Figure 4.

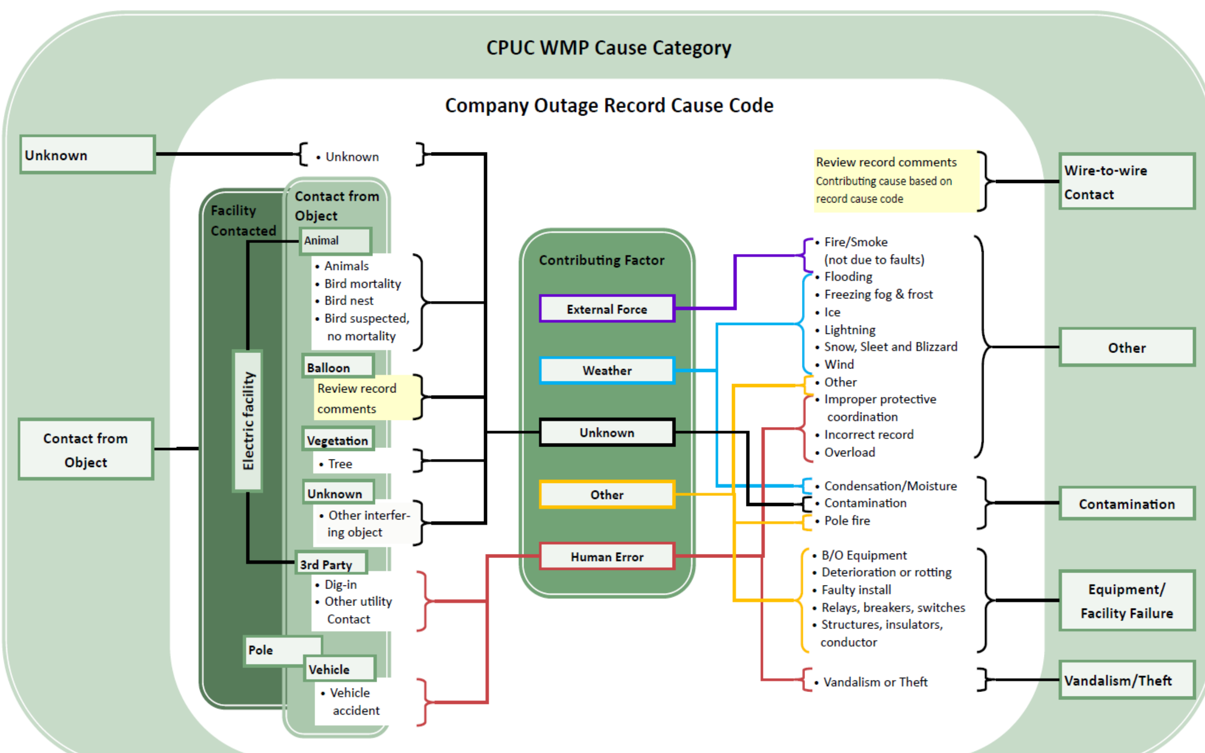
[9] Bouford, James D. "Spacer cable reduces tree caused customer interruptions." 2008 IEEE/PES Transmission and Distribution Conference and Exposition. IEEE, 2008.

Figure 4: PacifiCorp Risk Mapping Exercise



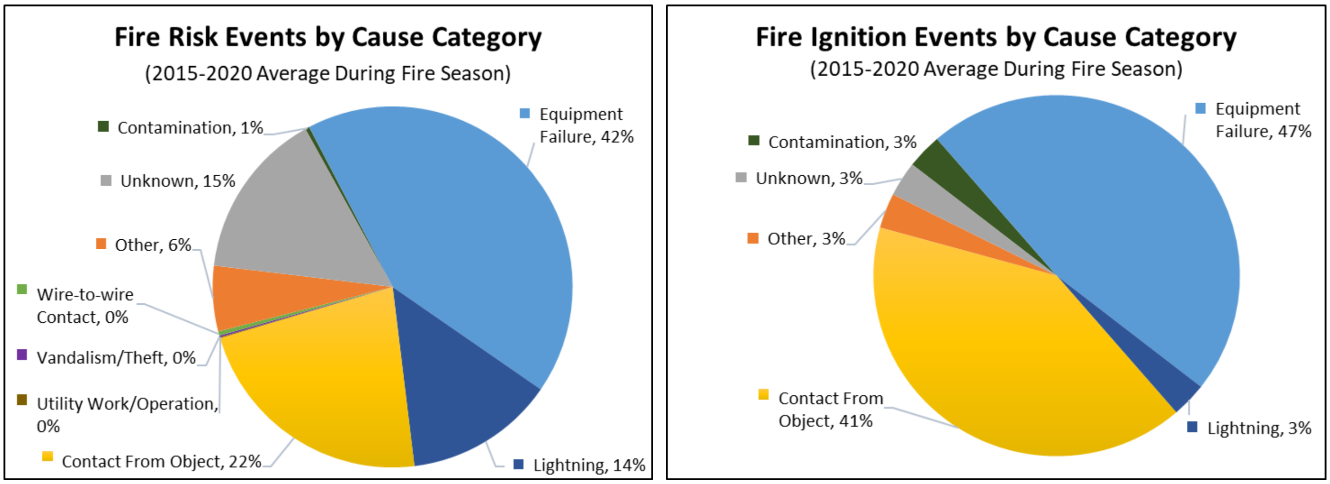
With this process, as outlined below in Figure 5, PacifiCorp evaluated outage causes (and sub-causes, as well as commented information) to establish a relationship between forced outages and risk event drivers.

Figure 5: PacifiCorp Outage Cause Evaluation



The company then determined the average percentage of fire risk events and ignition events over the 2015-2020 period as shows in Figure 6

Figure 6: PacifiCorp Fire Risk Events by Cause Category



The company then evaluated the probability (qualitatively scored and informed by the information above) of each ignition risk driver and its potential for ignition based on the season (fire and non-fire season) as shown in Figure 7. It was also segmented by transmission and distribution system, since the probabilities of each risk event driver and ignition risk were not equivalent. Qualitatively, PacifiCorp designated each cause either a low (L), medium low (ML), medium (M), medium high (MH), and high (H) by fire and non-fire season for the likelihood of the cause to result in an ignition to help establish priorities of mitigations.

Figure 7: PacifiCorp Fire Risk Events Assessment

Risk Event Driver		Non-Fire Season		Fire Season	
		Transmission	Distribution	Transmission	Distribution
Wire down event (regardless of cause)		M	M	H	H
Contact-from-object	Veg. contact	M	M	H	H
	Animal contact	L	L	L	ML
	Balloon contact	L	L	L	ML
	Vehicle contact	L	ML	M	MH
	Other contact-from-object	L	L	L	ML
Equipment / facility failure	Connector damage or failure	M	M	H	H
	Splice damage or failure	M	M	H	H
	Crossarm damage or failure	L	L	M	ML

	Insulator damage or failure	L	L	L	ML
	Lightning arrestor damage or failure	L	M	L	H
	Tap damage or failure	L	L	L	ML
	Tie wire damage or failure	L	L	L	L
	Other	L	L	L	L
Wire-to-wire contact	Wire-to-wire contact / contamination	L	L	ML	M
Contamination		L	L	L	ML
Utility work / Operation		L	L	L	ML
Vandalism / Theft		L	L	L	ML
Other		L	L	L	L
Unknown		L	L	L	L

Based on PacifiCorp's spacer cable pilot projects, the company is experiencing a 90% reduction in outage events. In order to evaluate this, PacifiCorp prepared pre-reconductor performance and contrasted it against post-reconductor performance and determined that the reduction in outages was approximately 90%. It is important to note that for these projects, since they were targeted specifically to environmental parameters that are visible (such as tree canopies or animal habitats), only the at-risk segments were reconductored (i.e., the entire zones of protection were not reconductored). The effect of this approach results in a high degree of confidence in the intended purpose of the project (against the specific risk driver). Should the measure be broadly extrapolated throughout the company's system, in the areas where these risk drivers are not prevalent their effectiveness is more problematic to evidence, since a longer duration of the countermeasure must be in place to determine that it was in fact, effective. To further explain, if an area is not prone to a specific risk driver, a longer history is required to experience a given risk event.

In the future, as the company reconductors entire zones of protection, it will have better certainty about the effectiveness of the mitigation against each ignition risk driver within that zone. For the initial projects, the scoping was directly motivated by reducing contact, primarily vegetation outage rates, and as a result the outage rates being measured are directly influenced by that decision. Even though the data is not perfect, it still provides a valuable insight into the expected reduction in risk from covered conductor. As the company constructs more projects and as time passes for outage events to accrue, PacifiCorp expects to further refine the outage rate reduction by ignition risk driver. For the ignition risk drivers that it is not able to confidently measure, PacifiCorp takes the 90% reduction in outage rate and modifies it with SME input to create estimated effectiveness values. The ignition risk drivers, the estimated reduction, and the explanation is summarized in Table 6.

Table 6: PacifiCorp Covered Conductor Mitigation Effectiveness Estimate

Ignition Risk Driver	Estimated Effectiveness Percent Reduction	Discussion
Vegetation Contact	90%	Vegetation contact is one of two primary drivers for the pilot project selection.

Ignition Risk Driver	**Estimated Effectiveness Percent Reduction**	**Discussion**
Animal Contact	90%	Animal contact is the second of two primary drivers for the pilot project selection.
Balloon Contact	99%	In general, expect contact from balloons to be mitigated.
Vehicle Contact	90%	Due to the increased strength of spacer cable systems, combined with increased resilience to wire-to-wire contact, estimate a 90% effectiveness.
Equipment Failure	90%	Much of the equipment used to construct bare overhead systems is replaced with different components. Additionally, phase conductors are not under tension. This estimated effectiveness is not incorporating downstream equipment such as transformers and protective devices.
Wire to Wire Contact	99%	Due to the forces experienced from vegetation contact, instances of wire-to-wire contact have been observed. No faults occurred.
Contamination	75%	Risk of contamination is estimated to be reduced due to systems being insulated beyond their standard NESC minimum ratings.
Vandalism/Theft	50%	In general, spacer cable has less risk of conductor theft as well as vandalism. Believe there are two areas where there could be increased risk of vandalism and theft, for example, damage from "gunshot" to the conductor covering, and theft of copper ground wiring.
Lightning	50%	Given spacer cables unique design where the messenger (neutral) is the topmost conductor, it acts as a grounded shield wire for the phase conductors. In addition, earth

Ignition Risk Driver	Estimated Effectiveness Percent Reduction	Discussion
		grounds are utilized every approximately 500 feet to further ground the system. With diligence in lightning arrester placement, estimate a 50% reduction in lightning-related faults.
Third Party	90%	Third-party including contact from joint use, boom arms, etc. should be mostly mitigated with spacer cable.

BVES

BVES has approximately 211 circuit miles of overhead conductor between 34.5 kV and 4.16 kV in its system. BVES started a covered conductor pilot program in Q2 2018 and completed it in Q3 2019 using two different types of cover conductor wires (394.5 AAAC Priority wire and 336.4 ACSR Southwire). Then BVES started the cover conductor Wildfire Mitigation Plan (WMP) late 2019 with a plan to cover 4.3 circuit miles on 34.5 kV over the next 5 years and 8.6 circuit miles on 4.16KV over the next 10 years. As of the end of Dec. 2021, BVES has covered approximately 21.1 miles between its 34 kV and 4 kV systems. BVES' average span length is approximately 150 feet and installing covered conductor on cross arms with Hendrix insulators. As part of its covered conductor program when there are spliced locations, BVES installs premade cold shrink kits (3M) and installs avian protection (raptor protection/wildlife guard).

Based on benchmarking with other utilities' estimated effectiveness against ignition risks, discussions with its covered conductor supplier, 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%. This is BVES's first initial look and as it installs more covered conductor and gathers more historical data, it will continue to assess the estimate of effectiveness. BVES presents its estimated effectiveness in Table 7.

Table 7: BVES Covered Conductor Mitigation Effectiveness Estimate

Ignition Risk Driver	Percent Reduction	Discussion (Contacts on Cover Conductor cable)
Vegetation Contact	90% +	Vegetation contact on 1, 2, 3 phase and/or neutral wire.
Animal Contact	90% +	Animal contact on 1, 2, 3 phase and/or neutral wire.

Ignition Risk Driver	Percent Reduction	Discussion (Contacts on Cover Conductor cable)
Balloon Contact	90% +	Balloon contact on 1, 2, 3 phase and/or neutral wire.
Wire down contact	90% +	Due to the following: tree/tree limb fallen on line, car hit pole , wind gust, etc.
Vehicle Contact	90% +	Vehicle Contact due to wire down on vehicle.
Wire to Wire Contact	90% +	Due to the wind gust forces causing tree/tree limb fall on line or just wire to wire contact.
Splice location contact	90% +	BVES installs Avian protection/raptor protection/wildlife guards and uses premade cold shrink kits (3M) on splice locations.
Vandalism/Theft	90% +	In BVES' service territory there is a low risk of conductor theft as well as vandalism. If vandalism occurs, Ex. damage from "gunshot" to the conductor covering installed.
Lightning Contact	90% +	During raining seasons, sometimes encounter a good amount of lightning strikes in BVES' service territory. BVES using priority covered conductor (flame resistant) cable.
Third Party	90% +	Third party including contact from joint use, boom arms, etc. should be mostly mitigated with covered conductor cable.
Flame Propagation along the covered conductor	90% +	Caused by Lightning or other.
Flame particle dripping	90% +	Caused by Lightning or other.

Liberty

To estimate the effectiveness of its Covered Conductor WMP initiative in mitigating wildfire risk, Liberty evaluated the ability of covered conductor to reduce each ignition risk driver, as seen in Table X below. Liberty employed an internal risk working group to assess the effectiveness of covered conductor and other system hardening initiatives in reducing wildfire risk. This working group consisted of SMEs across its engineering, operations, wildfire prevention and regulatory teams. The SMEs convened weekly to discuss in detail each ignition risk driver and the mitigation effectiveness of covered conductor and other system hardening initiatives. SMEs referenced Liberty's historic outage data, including the location and cause of the outage and any associated dispatch or filed notes included in its outage management database. SMEs discussed the extent to which covered conductor would reduce, eliminate, or not have an effect on the likelihood of a specific type of outage occurring and leading to an ignition. Outages were classified by the ignition risk drivers listed in the table below and an estimated mitigation effectiveness percentage was developed for each risk driver.

Table 8 explains the reasoning for the estimated effectiveness values. Liberty continues to benchmark its evaluation within the industry. As Liberty continues to collaborate and benchmark with its peer utilities, including through the Joint IOU Covered Conductor Working Group, it will revisit the estimated effectiveness metrics and revise as necessary.

Table 8: Liberty Covered Conductor Mitigation Effectiveness Estimate

Ignition Risk Driver	Covered Conductor Mitigation Estimated Effectiveness (%)	Reasoning
Animal contact	90%	• Line is potentially uninsulated at connection points, transformer taps and dead-ends (locations with higher probability of animal activity).
Vegetation contact	95%	• CC will handle most tree branches falling on it, and grow-in, but not an entire tree (fall-in).
Vehicle contact	50%	• If a car takes a pole out, there is a reasonable chance the circuit will remain in service. • A wire-down event from car-hit-pole will result in fewer faults with covered conductor .
Conductor failure	80%	• Conductor not totally fail-proof from branches (larger, heavier, falling further) or tree falls, potentially breaking poles and crossarms. Steel poles/fiberglass crossarms might mitigate some of this vs. wood.
Conductor failure - wire slap	95%	• Covered conductor largely eliminates mid-span wire-slap phase-to-phase faults
Conductor failure - wires down	80%	• See logic for vehicle contact

Ignition Risk Driver	Covered Conductor Mitigation Estimated Effectiveness (%)	Reasoning
Animal contact	90%	• Line is potentially uninsulated at connection points, transformer taps and dead-ends (locations with higher probability of animal activity).
Other - Including unknowns	75%	• Liberty suspects that many ‘unknown’ OMS outage cause codes are non-failure wire slap, light veg contact, lightning or animal because no damaged component can be found as a reason for protective device operation.
Weather - Snow (better defined)	90%	• Liberty’s covered conductor installation typically includes new poles and crossarms due to higher conductor loads. Poles designed to meet the GO95 strength requirements.
Weather - Lightning	15%	• Messenger wire on ACS attracts lightning strikes away from conductors.
Weather - Wind	90%	• Covered conductor largely eliminates mid-span wire-slap phase-to-phase faults
Pole Fire	80%	• ACS prevents bare wire from laying on the cross-arm and burning. • Tree wire has multi-layer jacket which greatly reduces opportunity for bare wire contact with wood supporting apparatus.

Next Steps

As detailed above, the utilities estimate the effectiveness of covered conductor between approximately 60 and 90 percent. In 2022, the utilities will continue to meet on a regular basis to discuss estimated effectiveness methods, data and calculations. The utilities will learn from the benchmarking, testing, and recorded results and collaborate to improve each utilities’ understanding and approach to estimate effectiveness. The utilities plan to discuss opportunities to align data and methods for greater comparability and will provide an update on these efforts in their 2023-2025 WMPs.

Recorded Effectiveness

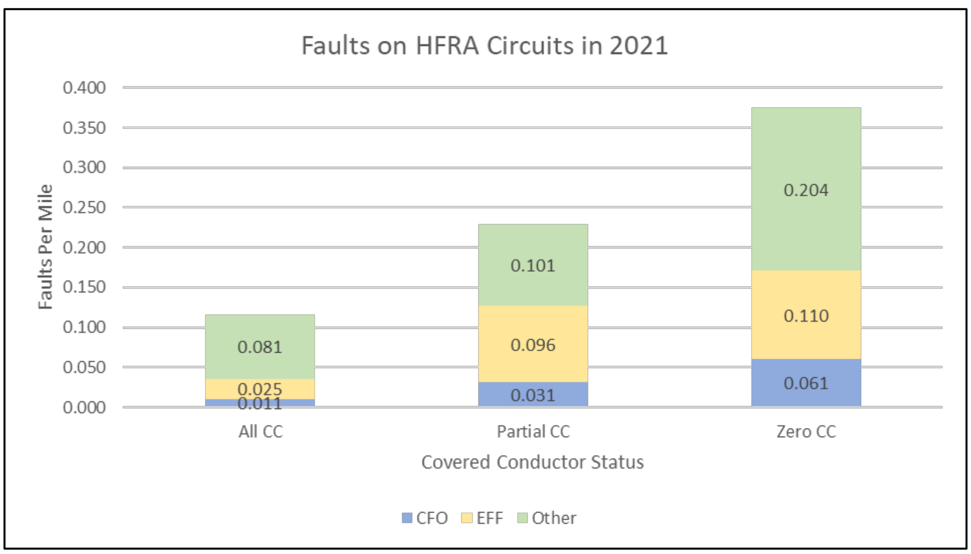
The utilities are in the early phases of covered conductor deployment and measuring its effectiveness. Though the utilities' data is limited, the early outcomes, as presented below, show covered conductor effectiveness at reducing the risk drivers that can lead to wildfires range between approximately 60 to 90 percent, which is consistent with the utilities' estimated effectiveness values, benchmarking, past testing results, and the results of the Phase 1 testing report. With the limited amount of data and the fact that the utilities have taken different approaches to measuring the effectiveness of covered conductor, in 2022, the utilities will work towards developing a common methodology (or multiple methods) all utilities can use for better comparability. The utilities also plan to continue discussions with the IEEE DRWG on methodologies to measure the effectiveness of covered conductor as part of a peer-review process. Below, the utilities describe data and analyses they have conducted regarding measuring the recorded effectiveness of covered conductor and collectively the utilities summarize future steps to improve these methods and updates to the data sets.

Covered Conductor Recorded Effectiveness

SCE

SCE is measuring the overall effectiveness of covered conductor by comparing events (primary wire downs, primary conductor caused ignitions and faults) on fully covered circuits to bare circuits in its HFRA on a per-mile basis in current years. As of November 2021, SCE's wire down and fire data does not show any events occurring on fully covered circuits. The data shows that circuits fully covered experience approximately 69% less or 31% of the faults that bare conductor do (see Figure 8).

Figure 8: SCE Faults on HFRA Circuits in 2021



As seen in Figure 8, SCE is using current (2021) data by comparing results (e.g., faults per mile) in HFRA for circuits that have been fully covered, partially covered and not covered as opposed to historical data, which may either over- or under-represent the benefits by not capturing weather variations year after year and data quality improvements in identifying and tracking risk events.

Since 2018, SCE has documented known contact-related events with covered conductor. In one instance, a tree fell on covered conductor lines, making contact with all three phases. In another case, energized covered conductor lines fell into adjacent trees after a vehicle struck a pole, as shown in Figure 9. These events did not result in faults, wires down, or ignitions because covered conductor was deployed and provide examples of effectiveness of covered conductor in the field.

Figure 9: Covered Conductor Contact with Vegetation After Car-Hit-Pole Ojai, California – July 24, 2020

PG&E

To align with the estimated effectiveness approach, in 2021, PG&E started to analyze its hardened facilities' performance with regard to recorded outages, incidents, and ignitions so that it can continue to refine its strategy and improve the scope and design of its Overhead Hardening Program. PG&E will also analyze the performance of any hardened facilities that experienced a wildfire in order to validate assumptions about the life expectancy and effectiveness of hardened facilities in various conditions.

The Overhead Hardening Program is still in its infancy which makes it difficult to have the amount of data needed to have statistical significance from this type of analysis. Initial analysis has been limited to counts of outages at the circuit segment level that compare the annual average from 2015-19 (pre-overhead hardening) to the 2020 (hardened) total count of outages where overhead hardening was completed in 2019 as shown in Table 9.

Table 9: PG&E Pre-Overhead Hardening Compared to Post Hardened Count of Outages

2015-2019 Average Outage Count	2020 Outages	Change	Percent [Ave -2020] / Ave
591	225	-366	62%

While the calculated outage reduction percentage (used as a measure of recorded effectiveness) matches the initial 62% estimated effectiveness, the results are understood to be preliminary and lack the geospatial accuracy needed for a truly recorded effectiveness.

Additionally, PG&E considered including ignitions, and incidents such as a wire down, or PSPS incidents (damage / hazard) in hardened sections to enhance the measurement of effectiveness of the Overhead Hardening Program, however the data scarcity was even greater for a meaningful analysis.

Going forward, PG&E's focus is to find ways to better capture geo location of a fault, and, if applicable, the damage and broken equipment. Industry-wide, fault location has historically been assigned to the device operated and not necessarily the actual coordinates where a fault occurs. This improvement in the quality of spatial data guarantees a more precise analysis of areas where overhead hardening has been completed.

Lastly, PG&E remains committed to explore ways to best calculate effectiveness and has established a biannual monitoring cadence with its Wildfire Governance Steering Committee to ensure continued improvement. These efforts will be shared with this working group to continue to improve methods to measure the effectiveness of system hardening initiatives.

SDG&E

SDG&E follows the same approach used to calculate the effectiveness of its Overhead Distribution Hardening, which is discussed in SDG&E's WMP in Section 4.4.2.3. SDG&E does not have sufficient data yet to draw any conclusions on the recorded effectiveness of covered conductor, as there is approximately only eighteen miles of covered conductor installed with an average age of less than one year. Across this small sample size, there have not been any faults on these covered conductor sections.

Moving forward, SDG&E will continue to track the mileage, years of service, and faults on all covered conductor circuit segments and will continue to collaborate with this working group to improve methods to measure the effectiveness of its system hardening initiatives. SDG&E's approach is to calculate the risk events per one hundred miles per year on segments that have been covered and compare the risk event rate before and after the installation of covered conductor.

PacifiCorp

As outlined above, PacifiCorp tracks risk events (forced outages) within each zone of protection (ZOP) with known conductor types and assumes homogenous performance across the ZOP; current processes do not establish specific locations where fault events occur, but are reconciled to the device that protects the ZOP. To establish the recorded effectiveness, PacifiCorp queried pre- versus post-installation performance with risk event drivers for all ZOPs having covered conductor (specifically spacer cable construction). It was important to recognize that legacy projects were focused on reliability and thus did not require reconductoring of the entire ZOP. As such, the recorded effectiveness calculations accounted for the percentage of the ZOP that wasn't reconductored. The smaller the percentage of the ZOP the less the confidence of the recorded effectiveness, while the higher the percentage of the ZOP the higher the confidence of the calculation.

Table 10 shows the performance before and after covered conductor installation, with several of the more recent projects not yet having sufficient history to calculate the effectiveness. As such, the table below summarizes PacifiCorp's experience of about 15-20 miles of the total covered conductor installed.

Table 10: Improvement Percentage for Covered Conductor/Spacer Cable Projects

Project Circuit	Install Year	Pre Install Fault Rate (per Mile)	Post Install Fault Rate (per Mile)	Improvement %	Zone Spacer Cable After (%)
4W8	2018	0.11737	0	100	35.72
4W8	2018	0.80326	1.11155	-38.38	78.82
5A15	2017	0.15403	0.09387	39.06	27.67
5A93-1	2007	0.55552	0.35134	36.75	15.92
5A93-2	2017	0.85087	0.41872	50.79	16.1
5K50	2018	0.23498	0.10819	53.96	63.42
5L82	2013	0.55291	0.14227	74.27	100
5L82	2013	0.39609	0	100	100
5L82	2013	0.13227	0	100	66.19

This data is summarized graphically below in Figure 10, where the improvement percentage is compared against the percentage of the ZOP that was reconductored. As can be seen, the higher the percentage of the ZOPs, the higher the recorded effectiveness when measured by faults (risk events) per mile.

Figure 10: Percentage of Covered Conductor (Spacer Cable) in Zone Versus Improvement Percentage

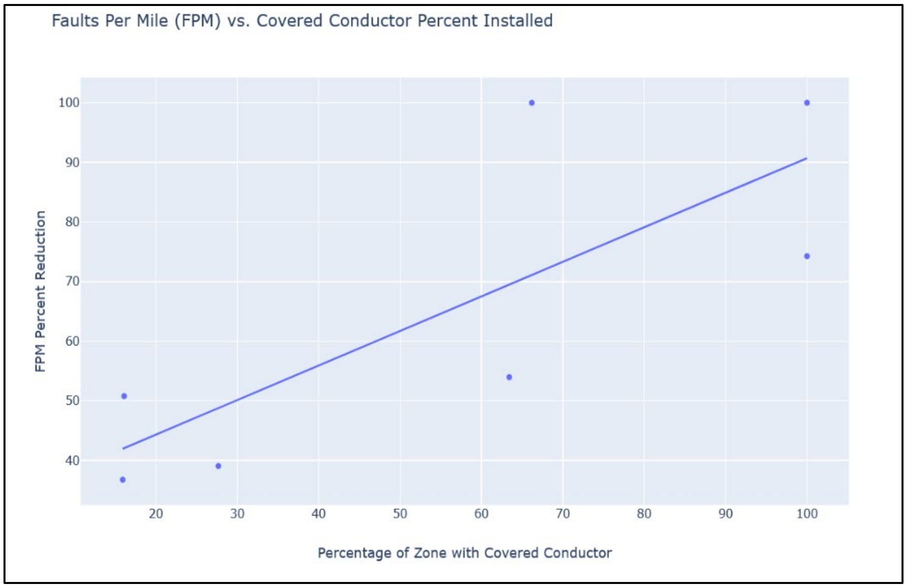
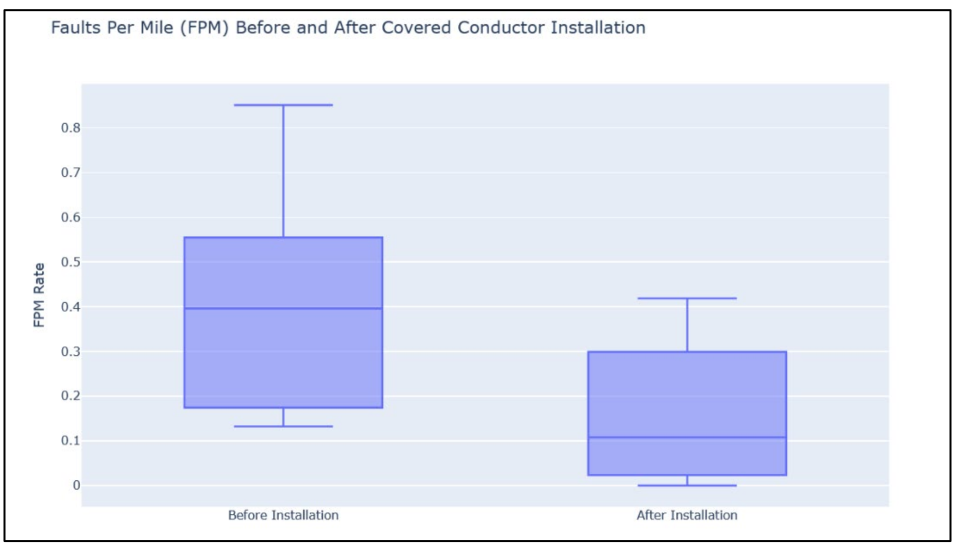


Figure 11 shows how the ZOPs performed before the mitigation was completed versus after the mitigation was completed, normalized based on the faults-per-mile recorded.

Figure 11: Comparison of Faults Per Mile Performance Before Versus After Covered Conductor (Spacer Cable) Installation



PacifiCorp has also documented known contact-related events with covered conductor. As shown in Figure 12, these events did not result in faults, wires down, or ignitions because spacer cable was deployed and provide examples of effectiveness in the field.

Figure 12: Examples of Effectiveness of Covered Conductor to Risk Events

BVES

BVES has approximately 211 circuit miles of overhead conductor between 34.5 kV and 4.16 kV in its system. BVES started a covered conductor pilot program in Q2 2018 and completed it in Q3 2019 using two different type of cover conductor wires (394.5 AAAC Priority wire and 336.4 ACSR Southwire). Then, BVES started the cover conductor WMP late 2019 with planning on covering 4.3 circuit miles on 34.5KV next 4 years and 8.6 circuit miles on 4.16KV next 10 years. As of end of Dec. 2021, BVES has covered approximately 21.1 miles between its 34 kV and 4 kV system.

In Q3 2018, BVES started a new tree-trimming contract with a new tree service contractor. BVES has been very aggressive with its vegetation manage program having up to four tree crews or more at a time to complete its three-year cycle and remediating any issue trees which has helped reduce outages from vegetation contacts.

As part of its WMP, in June 2019, BVES began replacing all explosion fuses in its service area with Trip Savers and Elf Fuses. BVES completed this project in May 2021, which eliminated the potential for ignitions from explosion fuses.

Currently, BVES has not had any outages, wire down, tree limbs and/or ignitions on the lines that have been covered. BVES is still in the early stages of its covered conductor program. As more areas are covered and as more time passes, BVES will be able to compile more recorded data to inform on the effectiveness of covered conductor. Table 11 provides a simple assessment of recorded outages since 2016 in BVES' system which shows a reduction of outages beginning in 2019.

Table 11: BVES 2016-2021 Recorded Outages Assessment

BVES, Inc.	12/10/2021
Year	# of outage
2016	163
2017	256
2018	118
2019	61
2020	84
2021	65

Liberty

Liberty's covered conductor program is relatively new, with the only significant projects being completed in 2020 and 2021. Because the program is new, data on the performance of covered conductor effectiveness will not yet demonstrate meaningful results based on the limited sample period and the wide variations in weather conditions. In addition, the covered conductor projects completed thus far represent a small percentage of each circuit and the outage data has only been evaluated on a circuit by circuit basis.

As an example, Liberty's Topaz 1261 circuit has 3.17 miles of covered conductor installed on the circuit which consists of an overall length of 55.6 miles. Table 12 shows historic 5-year forced outage data by outage risk driver for the Topaz 1261 circuit. As discussed in the Estimated Effectiveness working group section, Liberty identified significant outage risk drivers that could be mitigated with covered conductor and will use those outage risk drivers in its assessments of the effectiveness of its covered conductor projects. Liberty's forced outages on the Topaz 1261 circuit for 2021 are lower than the historic 5-year average. However, there were more forced outages in 2021 with a tree cause compared to previous years. In 2021, there were no outages recorded with wire slap as the cause, but there are only two recorded wire-slap causes in the study period. This example demonstrates that Liberty needs additional data to draw valid conclusions.

Table 12: Historic Forced Outages by Risk Driver for Topaz 1261 Circuit (2017-2021)

Outage Risk Driver	Historical Average (2017-2020)	2021
Wind/Flying Debris	2.5	1
Hardware/Equipment Failure	4	4
Vegetation	1	4
Deterioration	1	0
Wire Down	0.5	0
Animal	0.5	0
Wire Slap	0.5	0
Wildfire	0.25	0
Fire on Company Equipment	0.25	0
Total for Risk Drivers Listed	10.5	9

While Liberty's outage management system does provide five years of useful historic forced outage data by geospatial location, the following are data limitations that Liberty has identified and is working to improve:

- Only the approximate outage locations are documented by field crews. While the general area affected is valuable for evaluating performance, Liberty is working with its field crews to document location at a more specific level.
- There are limits to the way dispatchers code outages within Liberty's existing outage management system (OMS). Liberty is currently undergoing an upgrade to its OMS and is working with its operations, dispatch and engineering teams to improve the data and to identify outage metrics and risk drivers to include in the upgrade.
- The planned OMS upgrade will coincide with a budgeted GIS upgrade, closely followed by a budgeted AMI implementation. These combined implementations are expected to better capture cause documentation, geo location of faults, outage extent/duration, and protective device operation.

Next Steps

In 2022, the utilities will continue to discuss methods of measuring the effectiveness of covered conductor, document the risk events and data utilities track, and work towards developing common methods to measure the effectiveness of covered conductor for better comparability. Since each utility has different processes and technical systems related to the collection of outage data, the utilities will work towards aligning on common methods. Of particular concern is ensuring a method or methods that all utilities can employ given the complexity in interruption data and differences in, for example, outage management systems, communication technologies, business practices, and causation identification and reporting. Methods the utilities plan to discuss include, for example, measuring faults in HFRA per hundred circuit miles per year comparing results pre- and post-covered conductor installation. Other methods include, for example, measuring the number of faults experienced in the current year for circuits that have been covered and circuits that have not been covered in HFRA and other metrics to demonstrate ignition performance.   This will require SME discussions and review of outage, wire-down and ignition data across the utilities. The utilities also plan to refresh its data sets and discuss any incidents, trends, anomalies, etc.

Alternative Comparison

The utilities identified an initial list of viable alternatives to covered conductor and conducted workshops with SMEs from the six utilities to assess the effectiveness of these alternatives against the same risk drivers that covered conductor is designed to mitigate. A viable alternative is a mitigation or group of mitigations that would address, to a similar or greater degree, the risk drivers that covered conductor is designed to mitigate. The utilities also included existing and a new bare conductor system as part of this assessment. The utilities used the risk drivers in Energy Safety's non-spatial data requirements (specifically, the non-repeated distribution causes and sub-cause categories in the WMP Guidelines, Table 7.1) to conduct the assessment. Below, the utilities describe the covered conductor system and alternatives that were selected for this assessment, the general assumptions that were applied, present the results of its assessment including descriptions of the factors that lead to lower or higher effectiveness, and describe the additional analyses the utilities plan to perform in 2022 to further the utilities understanding of the effectiveness of covered conductor compared to alternatives.

Covered Conductor System

A covered conductor system generally refers to installing a conductor that is covered, replacing equipment/components that are required because of the covered conductor, such as insulators, cross arms, or poles (where applicable), replacing other equipment that is determined to reduce risk, improve resiliency/reliability and/or are cost-effective, and adding other protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment.

In very limited situations, it may be possible to simply re-string bare conductor with covered conductor. These limited situations would require all existing poles to withstand the heavier covered conductor and where polymer insulators are already in place. Simply re-stringing covered conductor would be a rare occurrence as it is not usually possible. As such, the utilities are comparing the relative effectiveness of alternatives to a covered conductor system, as described above, in their ability to reduce the risk drivers of ignitions.

Some of the risk drivers, such as Animal Contact, cannot be fully mitigated with covered conductor by itself. For example, you may also mitigate Animal Contact on a bare wire system by installing, wider cross arms(to increase the phase spacing) and coverings on jumper wires and at device connections. This presents some challenge in estimating the effectiveness of a system since it's not simply the covered conductor itself, but rather the combined mitigations working together to mitigate any given risk driver. As such, the utilities assumed that all overhead conductor-related alternatives include animal covers except the existing bare conductor system that is essentially a "do nothing" alternative.

Alternatives

Below, the utilities describe the alternative mitigations that were compared with a covered conductor system.

Existing Bare Conductor System (status quo)

Existing systems, with enhanced maintenance activities and advanced system protection measures can be viewed as an alternative for covered conductor depending on the specific locational risk within the specified area. For purposes of this assessment, the utilities assumed a "do nothing" scenario regarding any system hardening upgrades. In the analysis below, this is labeled as Existing Bare Conductor. While the six utilities may have different existing overhead bare conductor systems in their HFRA, the utilities generally assumed existing bare conductor systems

New Bare Conductor System (like-for-like replacement)

This involves re-conductoring existing bare systems with like-for-like replacement of bare conductor, crossarms, connectors, etc. and added protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment. This type of system can reduce wire downs by mitigating conductor failures caused by fault current surpassing the ampacity threshold the conductor was designed for. However, this system will still be vulnerable to contact-from-object risk, wire slap, and some types of equipment failure.

Upgraded and Fire Hardened New Bare Conductor System (stronger conductor tensile strength, increased spacing, and stronger/taller steel poles)

This alternative is patterned after SDG&E's original fire hardening of its 69 kV transmission and 12 kV distribution systems located in its HFRA. SDG&E evaluated years-worth of reliability data in which one of the findings was that small wire conductor, #4 AWG and #6 AWG, was a significant driver for risk-related events. This information, coupled with the increased awareness of localized wind speeds in high risk areas, led to design changes of how these lines were constructed. The minimum size of the conductors was increased for additional tensile strength in addition to sometimes using dual steel core for support instead of single steel core. Under the previous design standards, lines were constructed to withstand working loads under stress of 56 mph wind speeds. The new design standard was able to withstand higher wind speeds, in some cases 85 mph and even up to 111 mph in specific cases. In addition to upgrading the conductor, wood poles were replaced with steel poles and increased phase spacing was used to minimize the potential of wire slap or phase-to-phase and phase-to-ground contacts.

Spacer Cable System

The spacer cable system utilizes a diamond shaped spacer to support covered conductor in a spaced bundle configuration, a high-strength messenger wire using a weak-link design concept, wherein the poles are the strongest member of the system, with the messenger the next strongest, and specialized attachment brackets that are the least strongest, such that if an impact load is experienced on phase conductors or poles, the system remains intact, but that "fails" the attachment of the bracket to the pole allowing for it to be quickly reattached. This system is secured to poles primarily with fixed or flex tangent brackets, in which the messenger is the only connected conductor. The utilities generally assumed poles would be replaced with stronger steel and/or fire-resistant poles to support this system. The covered conductors are not tensioned (nor are they structural members) and instead are held together with spacers attached to a tensioned messenger and placed approximately 30-feet apart. The high-strength messenger wire provides greater strength than a covered conductor system. The utilities also generally assumed equipment/components would be replaced similar to a covered conductor system and added protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment.

Aerial Bundled Cable System

An Aerial Bundled Cable (ABC) system consists of one, two, or three individual cables that are fully insulated. The cables are wrapped together and, similar to a spacer cable system, supported by a high-strength messenger with a lashing wire. Because the cables in ABC are fully insulated, ABC can withstand continuous contact-from-objects for an indefinite time period. The high-strength messenger also provides the ABC system with mechanical protection from objects falling onto the line. For purposes of the assessment, the utilities assumed the ABC would be installed using stronger structures that combined with the high-strength messenger would provide greater strength than a covered conductor system. The utilities also generally assumed equipment/components would be replaced similar to a covered conductor system and added protection measures such as animal guards or avian proofing where conditions merit or are otherwise applicable in the respective environment.

Underground System

An underground system consists of underground cable (e.g., crosslinked polyethylene cable (XLPE) installed in PVC conduit), above-ground pad-mounted equipment (e.g., transformers) or equipment in vaults, cable terminations and joints, surge arrestors and grounding electrodes. Underground cable can be direct-buried, direct-buried in conduit, or encased in concrete. For purposes of this assessment, the utilities generally assumed an undergrounded system with above-ground pad-mounted equipment and the cable/conduit encased in concrete. Undergrounding of electric infrastructure can significantly reduce wildfire risk and potentially reduce the need and frequency for PSPS outages. Additional potential benefits of undergrounding include an increase in service reliability, especially during wind events, and the reduction of the need for vegetation management work, and in general, improved public safety. An underground system can take significantly longer to complete and is more costly to construct as compared to other system hardening alternatives. An underground system can also be very complex to construct taking into account, for example, topography, geology, environmental or culture considerations, and land rights. In some instances, it is infeasible to construct.

Remote Grid

This alternative is patterned after PG&E's Remote Grid program designed to remove long feeder lines and serve customers from a Remote Grid. A "Remote Grid" is a concept for utility service using standalone, decentralized energy sources and utility infrastructure for continuous, permanent energy delivery, in lieu of traditional wires, to small loads, in remote locations, at the edges of the distribution system. As an example, in PG&E's service area there are pockets of isolated small customer loads that are currently served via long electric distribution feeders, some of which traverse HFRA and require significant annual maintenance, vegetation management, or system hardening solutions. The reduction in overhead lines as these Remote Grids are built can reduce fire ignition risk as an alternative to, or in conjunction with system hardening and other risk mitigation efforts. The utilities generally assumed in its assessment the differences between either covering a long distribution feeder line or eliminating the long distribution feeder line and installing a Remote Grid. The utilities did not include in its assessment any remaining fire risks associated with serving the small customer loads from either the covered conductor line or within the Remote Grid, i.e., only the long overhead distribution feeder line was considered in this assessment. While Remote Grids are not a general alternative to covered conductor, as the assessment below indicates, they can be effective at reducing wildfire risk for a particular long overhead distribution feeder line that serves small customer loads.

Comparison

The utilities conducted workshops over multiple days to discuss each sub-driver (from Table 7.1 of the WMP Guidelines) and assessed whether the alternatives have lower, similar or higher effectiveness than a covered conductor system. The results are shown in Table 13. A red arrow represents a lower effectiveness, an orange arrow represents similar effectiveness, and a green arrow represents a higher effectiveness.

Table 13: Mitigation Effectiveness Comparison of Alternatives to Covered Conductor

Risk Event Driver	Sub-driver	Existing Bare Conductor System	New Bare Conductor System	Upgraded and Fire Hardened New Bare Conductor System	Spacer Cable System	Aerial Bundled Cable System	Undergrounding System	Remote Grid System
Contact-from-Object	Veg. contact	↓	↓	↓	↑	↑	↑	↑
	Animal contact	↓	↓	↓	↔	↔	↑	↑
	Balloon contact	↓	↓	↓	↔	↔	↑	↑
	Vehicle contact	↓	↓	↑	↑	↑	↑	↑
	Other contact from object	↓	↓	↓	↑	↑	↑	↑
Equipment / Facility Failure (EFF)	Connector damage or failure	↓	↔	↔	↔	↔	↑	↑
	Splice damage or failure	↓	↔	↔	↔	↔	↑	↑
	Crossarm damage or failure	↓	↔	↔	↑	↑	↑	↑
	Insulator damage or failure	↓	↔	↓	↔	↑	↑	↑
	Lightning arrestor damage or failure	↔	↔	↔	↔	↔	↑	↑
	Tap damage or failure	↓	↔	↔	↔	↔	↑	↑
	Tie wire damage or failure	↓	↔	↔	↑	↑	↑	↑
	Capacitor bank damage or failure	↔	↔	↔	↔	↔	↑	↑
	Conductor damage or failure	↓	↓	↓	↑	↑	↑	↑
	Fuse damage or failure	↓	↓	↓	↔	↔	↑	↑
	Switch damage or failure	↓	↓	↓	↔	↔	↑	↑
	Pole damage or failure	↓	↔	↑	↑	↑	↑	↑
	Voltage regulator / booster damage or failure	↔	↔	↔	↔	↔	↑	↑
	Recloser damage or failure	↓	↓	↓	↔	↔	↑	↑
	Anchor / guy damage or failure	↓	↓	↓	↔	↔	↑	↑
	Sectionalizer damage or failure	↓	↓	↓	↔	↔	↑	↑
	Connection device damage or failure	↓	↔	↔	↔	↔	↑	↑
	Transformer damage or failure	↔	↔	↔	↔	↔	↔	↔
	Other	↓	↓	↓	↔	↔	↑	↑
Wire-to-wire contact	Wire-to-wire contact / contamination	↓	↓	↓	↔	↑	↑	↑
Contamination	Contamination	↓	↓	↓	↔	↑	↑	↑
Utility work / Operation	Utility work / Operation	↓	↔	↔	↔	↔	↔	↔
Vandalism / Theft - Distribution	Vandalism / Theft	↓	↓	↓	↔	↔	↔	↔
Other- Distribution	All Other - Distribution	↓	↓	↓	↔	↔	↑	↑
Unknown- Distribution	Unknown - Distribution	↓	↓	↓	↔	↔	↑	↑

The analysis shows that covered conductor has greater effectiveness than existing, new, and fire hardened overhead bare conductor systems. In some instances, a fire hardened overhead bare conductor system could provide slightly higher mitigation effectiveness. For example, for car-hit pole (vehicle contact) or other pole damage causes, a hardened overhead bare conductor system was assumed to have much stronger poles preventing occurrences of pole damage and/or wire down from a car-hit-pole scenario. In general, a spacer cable system and an ABC system provide higher effectiveness than a covered conductor system due to their strength and in the case of ABC both its strength and greater insulation properties. An underground or Remote Grid system provides the highest effectiveness, noting that the analysis of the Remote Grid System scenario was based only upon eliminating a long overhead distribution feeder line serving an isolated community and does not account for any overhead facilities beyond the long overhead distribution feeder line.

Next Steps

In 2022, the utilities plan to expand this assessment of alternatives to mitigate wildfire risk by including other technologies and mitigations such as replacing fuses, installing Remote-Controlled Automatic Reclosers/Remote-Controlled Switches (RAR/RCS), as well as newer technologies that the utilities are exploring including, for example, REFCL technologies, OPD, EFD, and DFA. Additionally, the utilities will assess how to estimate the relative percent difference of effectiveness for the alternatives.

Potential to Reduce the Need for PSPS

As part of this sub-workstream, the utilities have documented their general approach to PSPS and conducted a comparison analysis, similar to the Alternatives analysis above, by conducting workshops with SMEs from the six utilities to assess alternatives compared with covered conductor in their ability to reduce PSPS impacts. The utilities used the same alternatives as described in the section above to conduct this assessment. Below, the utilities describe their PSPS approach. Collectively, the utilities summarize the ability of a covered conductor system to reduce PSPS impacts, provide an assessment of alternatives ability to reduce PSPS impacts compared to covered conductor, and describe additional analyses the utilities plan to perform in 2022 to further the utilities' understanding of the ability of covered conductor compared to alternatives to reduce PSPS impacts.

Utilities' PSPS Approach

Below, the utilities describe their company's approach to activating a PSPS event and whether they consider raising thresholds when circuits are covered.

SCE

SCE activates PSPS largely based on two factors. The first factor used to drive PSPS decisions is the FPI, which estimates the likelihood of a spark turning into a major wildfire. FPI is calculated using forecasted wind speed, dewpoint depression, and various fuel moisture variables which are generated from SCE's customized version of the Weather Research and Forecasting (WRF) model. SCE's FPI scores range from 1 to 17, and any score at or above 12 is considered high risk. SCE reviews fire potential related products from the National Weather Service (NWS) and the GACC to confirm the wildfire threat related to PSPS. The second factor used to drive PSPS decisions is wind speed. SCE considers the NWS Wind Advisory levels (defined as 31 mph sustained wind speed and 46 mph gust wind speed) and the 99th percentile of historical wind speeds in the area to set activation thresholds. The Wind Advisory level is chosen because of the propensity for debris or vegetation to become airborne, while a circuit's 99th percentile wind speeds represent rare or extreme wind speeds that a particular circuit sees around four times per year. In 2021, SCE raised its de-energization thresholds for isolatable segments or circuits that have had covered conductor installed. The de-energization threshold for isolatable segments with covered conductor is 40 mph sustained and 58 mph gusts, which aligns with the NWS high wind warning level for windspeeds at which infrastructure damage may occur.

Once SCE's meteorologists confirm weather forecasts show an upcoming breach of FPI and circuit-specific wind speed thresholds, SCE activates its PSPS IMT and begins preparations for the upcoming event. Whether remotely due to the COVID-19 pandemic, or in-person at SCE's Emergency Operation Center, the IMT begins notifying affected parties. Notifications are sent to first responders, public safety partners, local governments, tribal governments and critical infrastructure providers approximately 72 hours prior to de-energization, followed by notifications to all other customers in scope approximately 48 hours prior to de-energization. SCE continues to provide additional notifications as well as notifications of imminent de-energization as information becomes available during the PSPS events (discussed in Section 8.2.4), develop event and circuit-specific de-energization triggers (inputs to which are discussed in Section 8.2.2) and direct resources to perform pre-patrols of all circuits in scope. Decision-making factors and protocols for PSPS de-energization are discussed in SCE's WMP Section 8.2.2.

PG&E

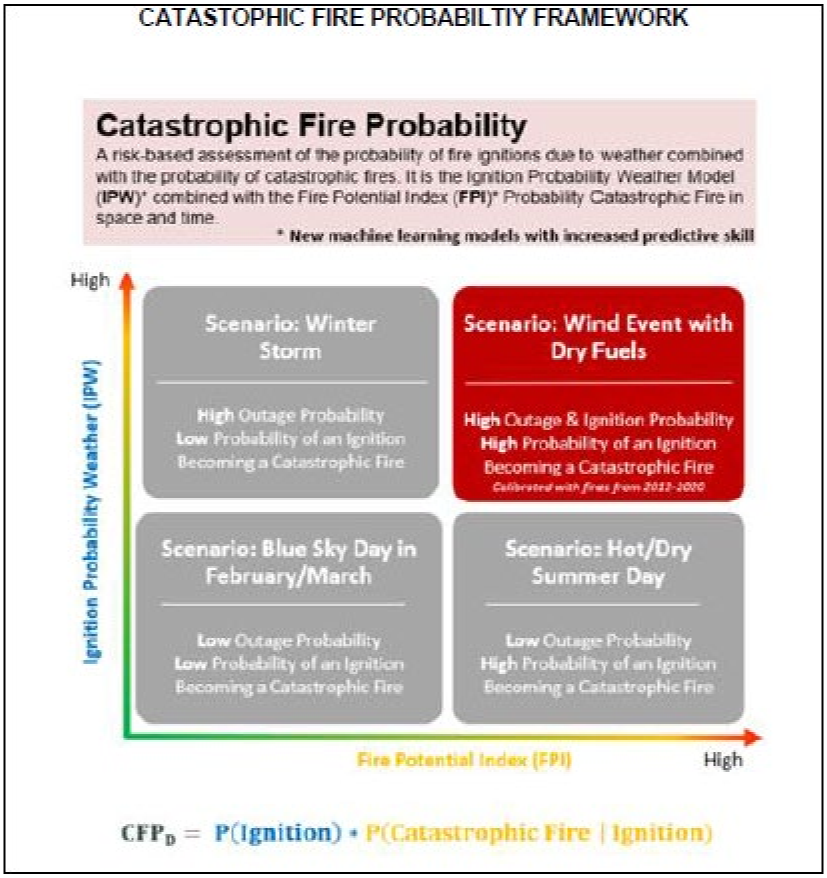
PG&E does not make specific changes in its PSPS protocols due to new improvements and mitigation initiatives, including grid hardening. The underlying models are based on historical data and not on estimating the effect of changes to system operations before they have occurred, which PG&E believes would be less accurate. However, since PG&E's PSPS models are based on historical data, new improvements and mitigation initiatives will be included in the models once the current changes are reflected in the historical data which the model incorporates over time. For example, when PG&E improves the quality of some specific assets, we expect a reduction in the chance of that asset causing an ignition. However, we do not manually input a reduction in the ignition probability in the model. Over time, the historical observed data is expected to change, and this data will feed into PG&E's models and gradually change its models' parameters.

PG&E's thresholds for PSPS are based on a risk assessment that combines the probability of utility related outages and ignitions, called the Ignition Probability Weather (IPW) model, and the probability of catastrophic fires, called the Fire Potential Index (FPI). This combination is called the Catastrophic Fire Probability (CFPD) and is given by the equation:

$$CFPD = p\ ignition * p\ catastrophic\ fire\ ignition = IPW * FPI$$

The IPW is a function of grid-performance given the weather conditions and is built using historical hourly weather data, outages, and ignitions in a machine learning model framework for localized areas. The guidance values PG&E utilizes when making a PSPS decision through the lens of this framework is a CFPD (IPW*FPI) value > 9. This value was determined by running 70 PSPS sensitivity studies from 2008 through 2020. Through this 13 year "lookback" analysis, PG&E evaluated the customer impacts through multiple dimensions (size, duration, frequency, repeat events, etc.), the days PSPS events would have occurred, as well as whether historic fires caused by utility infrastructure would have been de-energized using this analysis. The conceptual CFPD framework is presented in Figure 13.

Figure 13: PG&E Conceptual Catastrophic Fire Probability Framework



PG&E data scientists and meteorologists have taken steps to quantify the probability of outages, ignitions and catastrophic fires using both logistic regression and machine learning models. PG&E does not use wind speed thresholds on a per-circuit basis as a gauge of outage or ignition probability and therefore do not increase or decrease its wind speed thresholds where hardening has been performed. In PG&E's framework, the effects of grid-hardening and covered conductor would be handled in the IPW, which predicts the probability of utility-caused ignitions.

Overhead system hardening is expected to reduce the probability of outages and ignitions. PG&E believes that adjustments to PSPS thresholds should be considered carefully and based on robust performance data of survivability in the field during actual weather events. Covered conductor, for example, does not drive the fire ignition risk to zero. Trees can still fall into overhead lines and break covered conductor and cause an ignition. Based on aerial LiDAR, there are several million trees that have the potential to strike assets in PG&E's HFRA, which is an ignition pathway that has caused several catastrophic fires recently.

PG&E has built a PSPS model framework that can account for changes overtime based on actual performance data. The machine learning IPW framework (probability of ignitions) is flexible as PG&E does not have to consider each individual program such as covered conductor and EVM to adjust wind or PSPS thresholds on each circuit or circuit segment. Rather, the model framework addresses positive and negative changes in grid performance and reliability year-over-year as PG&E applies a time-weighted approach to weight more recent years of learned performance more heavily in the final model output. The model accounts for the performance of local grid areas hour-by-hour based on the wind speed observed at that hour and if outages or ignitions occur or not. The IPW model is 13 models trained on each year separately from 2008-2020 using hourly data and hourly outages. PG&E applies an exponential time-weighted approach to capture more rapid changes in local areas to be captured in the model (both negative - increased tree mortality, asset degradation, drought etc.; and positive – conductor and pole replacement, EVM, etc.). PG&E is in the process of updating the model with 2021 outage, ignition and historical weather data. When the model is updated, performance in 2021 will have the most model influence while 2008 will have the lowest.

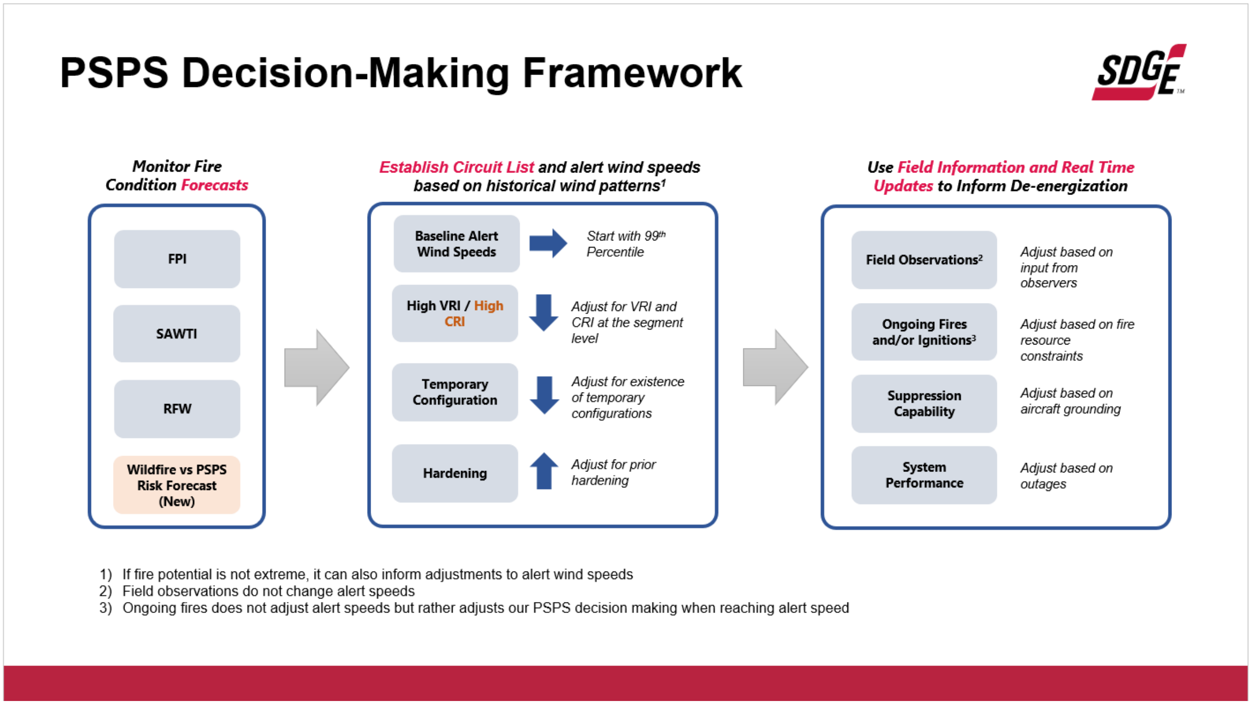
Since the IPW model accounts for changes over time and it evaluates PSPS through the risk-based assessment above, PG&E does not propose at this time adjusting its CFPD thresholds for circuits where grid-hardening has been performed. Instead, any positive effects from grid hardening, EVM, inspections, and other improvements will be trained in the Machine Learning IPW through this learned performance approach. Positive changes from any program or exogenous factors will lower the probability of outages and ignitions in these areas accordingly. In addition, if PG&E adjusts CFPD values to some circuits, it could make the fatal mistake of double counting the performance benefit achieved as changes in performance are inherently accounted for in the IPW model. PG&E welcomes feedback on its risk-based approach and ideas on how it can improve. One of the ideas PG&E is contemplating for future development of models is utilizing areas that have been hardened as a local feature of the IPW model.

SDG&E

SDG&E utilizes multiple factors to assist in the decision to de-energize. Figure 14 illustrates this PSPS decision-making framework. Some factors pertain to information in the field based on known compliance issues on the electrical system, active temporary construction/configuration of the electrical system, and a Circuit Risk Index (CRI) to identify locations in the system with a potential of having higher failure rates. Due to the dynamic nature of wildfire conditions SDG&E uses a real–time situational awareness technique to determine when to use PSPS, considering a variety of factors such as:

- Weather Condition - FPI
- Weather Condition - Red Flag Warnings
- Weather Condition - SAWTI
- Weather condition - 72-hour circuit forecast
- Vegetation conditions and Vegetation Risk Index (VRI)
- Probability of Ignition/Probability of Failure
- Field observations and flying/falling debris
- Information from first responders
- Meteorology, including 10 years of history, 99th and 95th percentile winds
- Expected duration of conditions
- Location of any existing fires
- Wildfire activity in other parts of the state affecting resource availability
- Information on temporary construction

Figure 14: SDG&E PSPS Decision-Making Framework



To-date, SDG&E has installed approximately 18 miles of covered conductor with an average age of less than one year. Therefore, SDG&E has not yet accumulated sufficient data to determine exactly how PSPS criteria will differ on circuit-segments that consist entirely of covered conductor versus bare conductor, though SDG&E does anticipate higher wind speed tolerances in these areas. In addition to real-world experience, and operations and benchmarking with other utilities, SDG&E will have a third-party evaluate the likelihood and effect specific to covered conductors clashing at various wind speeds to understand and help quantify any potential increases to wind speed tolerances on covered conductor segments.

PacifiCorp

PacifiCorp has historically leveraged multiple factors when deciding to implement a PSPS. Throughout 2021, PacifiCorp's newly established meteorology department worked to develop the capability to support real time risk assessments and forecasting and inform decision making protocols during periods of elevated risk such as PSPS assessment and activation. Situational awareness reports are generated daily which identify where fuels (dead and live vegetation) are critically dry, where and when critical fire weather conditions are expected (gusty winds and low humidity), and where and when the weather is forecast to negatively impact system performance and reliability. It is the intersection of these three factors that highlights an elevated risk to be considered for a potential PSPS event. These factors are then layered alongside real time local conditions such as real time weather measurements and field observer reports, as well as dynamic input from Public Safety Partners to characterize the local impact of a PSPS. All of these factors combined are used to determine whether to implement a PSPS.

During 2021 the following forecasted factors were considered in the decision to implement a watch:

- Comparison of forecasted wind gusts to localized history trends

- GACC-7 Day Fire Potential Outlook (High Risk with a Wind Trigger)
- Presence of any advisories such as the Fuels and Fire Behavior Advisory in effect for Northern California
- Local drought conditions
- Vapor Pressure Deficit
- Keetch-Byram Drought Index
- Presence of any Red Flag Warnings

In addition, the following real time observations were additionally included in the decision to de-energize:

- Actual wind gusts in the area
- Field observer reports
- Observer input regarding any observed precipitation (or other meteorological input)
- Measured wind speeds at utility owned weather stations
- Approximate relative humidity forecasted vs actual
- Local public safety partner input

While PacifiCorp continues to refine its methodology for determining inputs critical to making PSPS decision, however, at least for 2022, PacifiCorp does not anticipate at this time that covered conductor coverage will modify its PSPS decision-making process because PacifiCorp does not have full covered conductor coverage on any circuit or controllable sub-circuit. However, as the company increases covered conductor coverage, it will continue to assess its effectiveness, and expect it to impact its decision-making once the necessary coverage and operational history is obtained.

Liberty

In evaluating when a PSPS event should be initiated, Liberty monitors local weather conditions with its weather stations throughout its service territory and collaborates with Reax Engineering, a fire and weather scientific consultant, the National Weather Service (NWS) in Reno, Nevada, and local fire officials. The initiation of PSPS events are influenced by the following factors:

a. Red Flag Warnings: Issued by the NWS to alert of the onset, or possible onset, of critical weather or dry conditions that would lead to increases in utility-associated ignition probability and rapid rates of fire spread.
b. Low humidity levels: Potential fuels are more likely to ignite when relative humidity is low and vapor pressure deficit is high.
c. Forecast sustained winds and gusts: Fires burning under high winds can increase ember production rates and spotting distances. Winds also can transfer embers from lower fire risk areas into high risk areas, igniting spot fires and increasing wildfire potential.
d. Dry fuel conditions: Trees and other vegetation act as fuel for wildfires. Fuels with low moisture levels easily ignite and can spread rapidly.
e. Observed Energy Release Component (ERC)
f. Observed wind gusts
g. Observed Fosberg Fire Weather Index (FFWI)
h. Observed Burning Index (BI)

Liberty employs two de-energization decision trees, one for the Topaz and Muller 1296 r3 PSPS zones, and another for all other zones. In each case, the ERC, observed wind gust, and FFWI criteria are evaluated simultaneously to test whether any exceed the defined threshold. Figure 15 and Figure 16 represent the de-energization decision trees:

Figure 15: Liberty De-energization Decision Tree (Topaz and Muller 1296 r3 Zones)

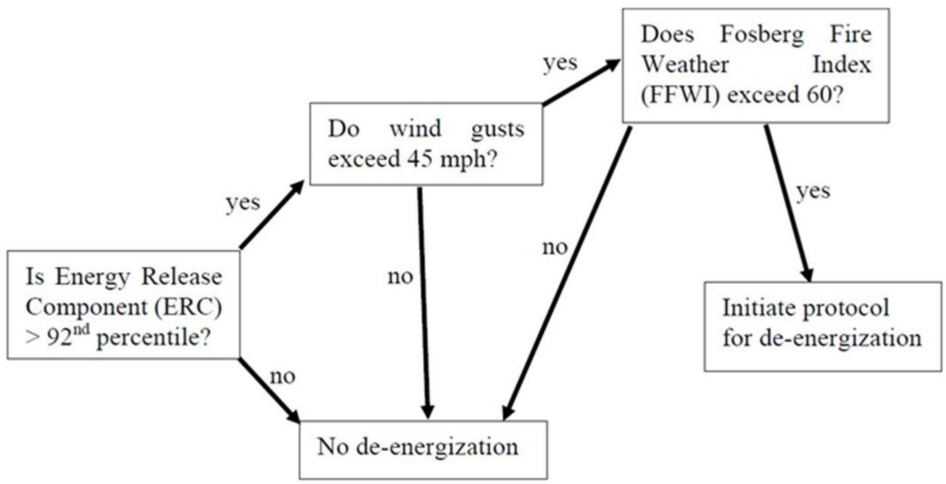
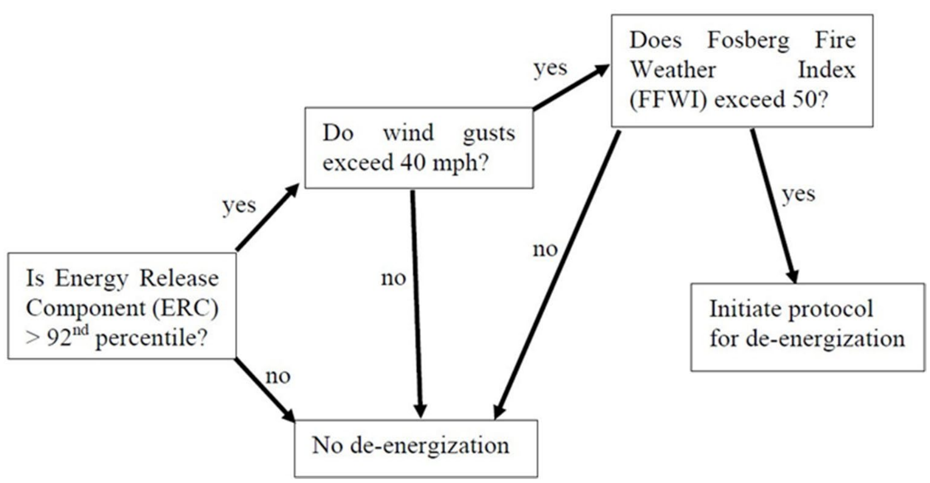


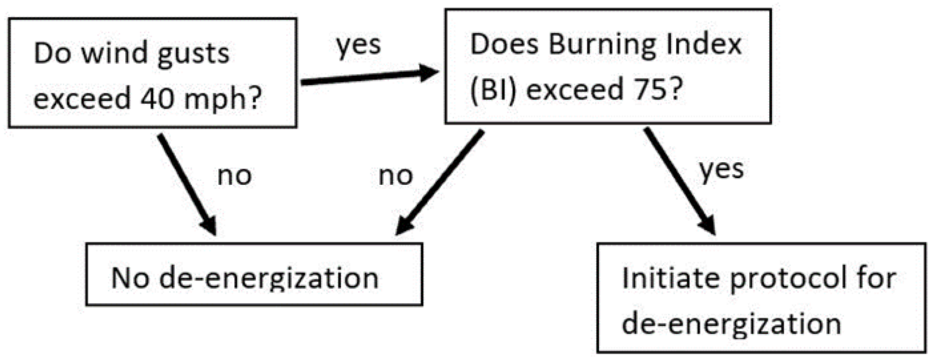
Figure 16: Liberty De-energization Decision Tree (All Other Zones)



In January 2021, Liberty's Fire and Weather Scientific consultant, Reax Engineering, formulated an enhanced version of its fire weather forecasting tool to include an additional parameter known as Burning Index (BI). BI adds an increased layer of information regarding fire potential to its already robust predictive formula. It accounts for predominant fuel type, live and dead fuel moisture, and short-term fluctuations in fire weather conditions. Use of this new formula with increased information from newly installed additional weather stations enables further granularity in the area of alternative responses to initiating a PSPS, such as managing recloser technology, de-energizing specific circuits and /or increasing patrols in specific geographic areas of concern. Liberty now utilizes both the current predictive formula and the enhanced model in order to assess improved data.

Figure 17 shows the current BI/gust de-energization formulation that is being evaluated by back testing against historical weather station observations and archived weather forecast data. The purpose of this formulation is to try to better capture "black swan" events, where extremely high winds may still have the ability to cause dangerous fire conditions even though temperatures are low and humidity levels are not critical, which can happen in the spring or fall more than the middle of the typical fire season.

Figure 17: Liberty's Current Burning Index / Gust De-energization Formulation



BVES

BVES evaluates many factors when initiating a PSPS event. However, in general, BVES will initiate a PSPS event when the NFDS fire danger forecast is high Risk (Brown, Orange or Red), and the actual sustained wind or 3-second wind gusts exceed 55 mph. In addition, BVES may initiate a PSPS if in the Utility Manager's judgement, actual conditions in the field pose a significant safety risk to the public. Individual circuits are evaluated for PSPS and may be individually de-energized to limit the area impacted by a PSPS.

Once complete overhead circuits are hardened and covered conductor is installed, BVES will consider raising the wind speed threshold for PSPS. The revised wind speed threshold for overhead structures with covered conductors is currently under evaluation. To date, BVES has never been required to activate a PSPS event.

Covered Conductor Potential to Reduce PSPS Risk

As described in the sections above, utilities generally believe that a fully-isolatable circuit-segment or zone of protection that has covered conductor can reduce PSPS impacts beyond an overhead bare conductor system. SCE, for example, increases its de-energization threshold for isolatable circuit-segments with covered conductor from 31 mph (sustained wind gusts) and 46 mph (gust) to 40 mph (sustained) and 58 mph (gust), which aligns with the National Weather Service (NWS) high-wind warning level for windspeeds at which infrastructure damage may occur. However, the rule of thumb starting point is not always 31 mph and 46 mph and instead is based on NWS high wind warning (potential asset damage). Furthermore, through back-casting analysis of 2021 PSPS events, SCE estimates that its efforts in grid hardening (largely due to covered conductor), situational awareness, and improved risk modeling (which allowed for adjustments to PSPS thresholds) helped reduce Customer Minutes of Interruption (CMI) by 43%, the number of customers de-energized by 42%, and the number of circuits de-energized by 29% from what they otherwise would have been under the same weather conditions. These data demonstrate that covered conductor provides PSPS benefits compared to overhead bare conductor systems. As the other utilities gain experience in installing more covered conductor, they plan to continue to assess raising their de-energization criteria for isolatable circuit-segments or zones of protection that are fully covered.

Alternative Comparison

The utilities conducted workshops over multiple days to discuss and assess whether the alternatives have lower, similar or higher benefits than a covered conductor system in reducing PSPS impacts. The utilities considered three PSPS benefits: 1) reduce PSPS frequency (# of de-energizations), Reduce PSPS duration (CMI), and reduce number of customers impacts by PSPS (i.e., customers in scope). The results are shown in Table 14. A red arrow represents a lower benefit, an orange arrow represents similar benefits, and a green arrow represents a higher benefit.

Table 14: PSPS Impact Benefits Comparison of Alternatives to Covered Conductor

PSPS Event Impact	Existing Bare Conductor System	New Bare Conductor System	Upgraded and Fire Hardened System	Spacer Cable System	Aerial Bundled Cable System	Undergrounding System	Remote Grid System
Reduce PSPS Frequency (# of de-energizations)	↓	↓	↔	↑	↑	↑	↑
Reduce PSPS Duration (CMI)	↓	↓	↔	↑	↑	↑	↑
Reduce Number of Customers Impacted by PSPS (customers in scope)	↓	↓	↔	↑	↑	↑	↑

The analysis shows that covered conductor has greater PSPS benefits than existing and new overhead bare conductor systems. SDG&E's upgraded and fire hardened system has shown benefits in reducing PSPS frequency, duration, and number of customers impacted. The utilities did not quantify these benefits to determine how much different are the benefits of a fire hardened bare overhead system compared to a covered conductor system and thus identified for this initial assessment a similar benefit. Similar to the assessment in the section above, a spacer cable system and an ABC system provide could provide higher benefits than a covered conductor system due to their strength and in the case of ABC both its strength and greater insulation properties. An underground or Remote Grid system provides the highest-level of benefits. Please note that the Remote Grid System scenario was based only on a long overhead distribution feeder line serving an isolated community and does not account for any overhead facilities beyond the long feeder line.

Next Steps

In 2022, the utilities plan to expand this assessment of covered conductor and alternatives in their ability to reduce PSPS impacts by including other alternative technologies and mitigations such as replacing fuses, installing RAR/RCS as well as newer technologies that the utilities are exploring including, for example, REFCL technologies, D-OPD, EFD and DFA. Additionally, the utilities will assess how to estimate the relative percent difference of the benefits for the alternatives.

Costs

The utilities have prepared an initial capital cost per circuit mile comparison of the installation of covered conductor. To construct this unit cost comparison, the utilities organized their capital costs (and/or estimates) into six cost categories. These categories include labor, material, contract, overhead, other, and financing. Labor represents internal utility resources, such as field crews, that charge directly to a project work order. Materials include conductor, poles, etc. that get installed as part of a project. Contract represents all contractors, such as field crews and planners, and consultants utilities use as part of their covered conductor programs. Overhead represents costs, such as engineers, project managers and administrative and general, that get allocated to project work orders. Other represents costs such as land fees, permit fees and costs not assignable to the other categories. Financing represents allowance for funds used during construction (AFUDC) which is the estimated cost of debt and equity funds that finance utility plant construction and is accrued as a carrying charge to work orders. These cost categories are intended to capture the total capital cost per circuit mile of covered conductor installations. For purposes of this report, the utilities obtained recorded and/or estimated costs for construction that occurred during 2021. Table 15 shows the initial covered conductor capital unit cost per circuit mile comparison across the six utilities.

Table 15: Comparison of Covered Conductor Capital Costs Per Circuit Mile

Cost Components	SCE		PG&E		SDG&E		Liberty		PacifiCorp		Bear Valley	
	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%	Cost per Circuit Mile	%
Labor (Internal)	$ 8,000	1%	$ 209,000	19%	$ 182,000	13%	$ 56,000	4%	$ 2,000	0%		
Materials	$ 115,000	20%	$ 161,000	15%	$ 130,000	9%	$ 132,000	8%	$ 204,000	34%	$234,000	23%
Contractor	$ 335,000	59%	$ 470,000	43%	$ 481,000	34%	$1,167,000	75%	$ 272,000	45%	$733,000	71%
Overhead (division, corporate, etc.)	$ 96,000	17%	$ 226,000	21%	$ 418,000	29%	$ 188,000	12%	$ 62,000	10%	$38,000	4%
Other	$ 5,000	1%	$ 6,000	1%	$ 173,000	12%	$ -	0%	$ 60,000	10%	$26,000	3%
Financing Costs	$ 6,000	1%	$ 11,000	1%	$ 43,000	3%	$ 9,000	1%	$ 6,000	1%		
Total	$ 565,000	100%	$ 1,083,000	100%	$ 1,427,000	100%	$1,553,000	100%	$ 606,000	100%	$1,031,000	100%

As illustrated in Table 15, the capital cost per circuit mile ranges from approximately $565,000 to approximately $1.5 million. The capital cost per circuit mile for covered conductor varies due to multiple factors such as type of covered conductor system and components installed, terrain, access limitations, permitting, environmental requirements and restrictions, construction method (e.g., helicopter use), amount of poles/equipment replaced, degree of site clearance and vegetation management needed, and economies of scale. Below, the utilities generally describe the make-up of their covered conductor capital costs and the factors that contribute to the cost differences.

Covered Conductor Capital Costs

SCE

CC Unit Cost Make Up

The costs in SCE's WCCP incur through the main cost categories of labor, materials, contracts, overhead, and other and are captured in SAP work orders. SCE's unit costs have historically been presented as direct costs only (exclude corporate overheads and financing costs), and is the average cost of nine different regions within SCE's service area. For purposes of this report, SCE has added corporate overheads (to the overhead cost category) and financing costs to its direct unit cost for comparison with the other utilities.

SCE has two covered conductor designs that vary depending on system voltage requirements. These include 17 kV and 35 kV covered conductor designs, the former of which SCE utilizes on its 12 kV and 16 kV distribution systems, and the latter of which SCE utilizes on its 33 kV distribution systems. The primary difference between these two designs is the thickness of the inner and outer layers. For example, 35 kV covered conductor design has a thicker covering, allowing it to withstand intermittent contact at higher voltages. Additionally, SCE uses four ACSR conductor sizes (i.e., 1/0 AWG , 336.4 (18x1) AWG, 336.4 (30/7) AWG, 653.9 AWG) and three copper conductor sizes (i.e., #2 AWG, 2/0 AWG, 4/0 AWG). Circuit and customer loading requirements will determine the conductor size. SCE may also use higher strength conductors to resolve ground clearance issues in areas subject to ice. The vast majority (99%) of SCE's covered conductor installations have been with the 17 kV covered conductor design which is lower cost than the 35 kV covered conductor design.

SCE installs covered conductor in an open-crossarm configuration. In this configuration, the conductor is self-supporting and attached to insulators on crossarms at the structure. SCE's WCCP also includes the installation of FRPs, composite crossarms, wildlife covers, polymer insulators, and vibration dampers. SCE uses FRPs, which are more expensive than wood poles, when pole replacements are required to meet pole-loading criteria. SCE replaces, on average, between 10 to 12 poles per circuit mile. Composite crossarms are also used to replace traditional wood crossarms as part of the WCCP. Like composite poles, composite crossarms are also higher cost than wood crossarms. SCE also employs wildlife covers and installs them on dead-ends, terminations, equipment jumper wires, connectors, and equipment bushings. In areas below 3,000 feet in elevation or high-tension installations, SCE requires the use of vibration dampers to mitigate conductor damage due to Aeolian vibration.

SCE primarily uses contractors to construct its covered conductor projects and a mix of contract and SCE labor to design its covered conductor projects. SCE field labor and contract field labor costs are charged directly to the project work orders. SCE design resources charge a division overhead account that gets allocated to work orders because SCE planners work on multiple types of projects. Costs for design scope performed by contractors is charged directly to the covered conductor work order (contract category) because this contracted work is specific to covered conductor projects. Materials such as conductor, poles, and crossarms are charged directly to the project work order. The Overhead category includes operational resources and items centrally managed and include costs such as equipment (e.g., vehicles, tools and supplies for field work) and managerial resources that are allocated to work orders. As noted above, the Overhead category also includes corporate overheads, which includes costs for administrative and general, pension and benefits, payroll taxes, injuries and damages, and property taxes.

Cost Drivers

SCE's covered conductor projects have an estimated timeframe of 16 – 22 months from initial scoping to project completion. There are many factors that may impact the total project lifecycle and costs, including permitting and environmental requirements, easements, geography and terrain, construction resource availability, and other construction-related factors. The largest driver of the cost is typically the contract cost for which contractor rates and construction time vary across locations in SCE's HFRA. For example, regions with more difficult terrain and mountainous areas typically have higher contractor rates. Projects in these areas also typically take longer to construct and require more costly construction methods (e.g., helicopter use). Beyond challenging terrain, projects can take more time due to other factors such as permitting, weather (e.g., rain/snow conditions, Red Flag Warning (RFW) days, etc.), and environmental restrictions (e.g., nesting birds that don't allow crews to work in certain areas until the birds have fledged). There are also many other drivers that can increase costs such as local agency restrictions (e.g., only night work allowed), direct environmental costs (e.g., if biological monitors are required), vegetation (i.e., requires vegetation clearing), access constraints (i.e., requires helicopter construction and/or access road rehabilitation), customer impact (i.e., temporary generation required for a circuit), and operating restrictions (e.g., crews are pulled off work). Many of these factors can also limit flexibility and reduce productivity causing construction costs to increase. The cost per circuit mile in some regions, such as SCE's Rurals Region, is more expensive than other regions. In some instances, this cost difference can be $300,000 or more per circuit mile.

As seen in Table 15, SCE's unit cost is the lowest of the six utilities. While SCE has described many factors that affect its covered conductor costs, some of the reasons why SCE's costs may be lower than the other utilities include economies of scale with SCE installing over 1,000 circuit miles per year and its ability to bundle work for its contractors. Bundling work enables multiple projects to be completed in the same general area which minimizes mobilization and demobilization costs and increases contractor productivity. SCE has also not generally observed a steady nor large amount of vegetation management or access road rehabilitation costs across its installations. With thousands of circuit miles installed, these types of incurred costs are low when averaged across SCE's portfolio of completed installations. As noted above, SCE also only replaces, on average, 10 to 12 poles[10] per circuit mile and its WCCP is focused on covered conductor and does not include other major equipment upgrades.

PG&E

CC Unit Cost Make Up

PG&E's data set represents System Hardening projects scoped by Asset Management and approved by its Wildfire Steering Governance Committee. The covered conductor projects go through the following major phases to completion:

- Estimating and Design
- Dependency (Permitting, Land Rights and Environmental Review)
- Construction Resourcing and Contracting

[10] SCE's average number of poles per circuit mile is approximately 29. As such, 10-12 poles represents approximately 34% to 41% of the average number of poles per circuit mile.

- Construction
- Document and Close Out

A subset of these projects is "Fire Rebuild" projects. These set of System Hardening projects arise from hardening scope after a fire or other emergency events in Tier 2/3. Due to the emergency nature to rebuild assets quickly to serve the community, all the steps described above in base System Hardening are accelerated.

PG&E's unit cost analysis is based on fully completed projects with costs-since-inception (including costs from previous years) recorded in its system of record (SAP). Based on that criteria, the data set captures 111 miles worth of projects that were completed in 2021. Construction transpired in 11 different divisions with varying terrains and conditions. 14 miles were Fire Rebuild, which typically have a lower unit cost, the remaining 96 were Base (regular) System Hardening.

Costs were organized per the six main categories agreed upon with the other utilities. The summary table blends both contract and internally resourced projects. 44 miles were constructed using external crews, categorized as Contract and 66 miles were constructed using Internal labor, categorized as Labor.

PG&E's Overhead Hardening (covered conductor installation) scope achieves risk reduction through these foundational elements: bare primary and secondary conductor replacement with covered equivalent, pole replacements, non-exempt equipment replacement, overhead distribution line transformer replacement with transformers that have FR3 fluid, framing (composite crossarms and insulators) and animal protection, and vegetation clearing.

Cost Drivers

PG&E's covered conductor installation costs are driven by these key contributors:

- Pole replacement – nearly 100% of the poles require replacement due to the additional weight/sag of the new covered conductor.
- PG&E incorporates numerous initiatives into a single hardening project. Non-exempt equipment and ignition component replacement impacts the cost by including the material and labor installation cost of the new equipment where it requires replacement.
- Vegetation clearing in support of the new overhead line can be a significant cost added to these projects. Both the increased height of the poles, the widened cross-arms, and the increased sag of the line can vary the cost considerably. This cost alone can add between $50,000 to $400,000 per mile depending on the terrain and the location of the line. The rural nature of much of the high-risk HFTD infrastructure drives this need.

SDG&E

CC Unit Cost Make Up

Each project goes through a six-stage gate process as follows:

Stage 1 – Project Initiation (duration ~1-3 months)

Stage 2 – Preliminary Engineering & Design (duration ~6-9 months)

Stage 3 – Final Design (duration ~3-5 months)

Stage 4 – Pre-Construction (duration ~1-2 months)

Stage 5 – Construction (duration ~3-4 months)

Stage 6 – Close Out (duration 8~-10 months)

The total duration of a project has an estimated duration of approximately 22 to 33 months.

SDG&E's covered conductor per mile unit capital costs is made up of the following six major cost categories:

1. Labor (internal) – directs costs associated with SDG&E full-time employees (FTE), including but not limited to individuals from project management, engineering, permitting, environmental, land management, and construction departments. This cost assumes approximately 25% of the electric work is completed by internal SDG&E construction crews.
2. Materials – estimated costs of material used for construction including steel poles, wire, transformers, capacitors, regulators, switches, fuses, crossarms, insulators, guy wire, anchors, hardware (nuts, bolts, and washers), signage, conduit, cable, secondary wire, ground rods, and connectors.
3. Contractor – estimated costs for construction-related services, including civil construction contractors for pole hole digging, anchor digging and substructures, and street/sidewalk repair; electrical construction for pole setting, wire stringing, electric equipment installation and removals; vegetation management where required including tree trimming or removal, and vegetation removal for poles and access paths; environmental support services including biological and cultural monitoring; traffic control; and helicopter support for pole setting, wire stringing, and removals. This cost assumes approximately 75% of the electric work is completed by contract crews.
4. Overheads – estimated costs associated with contracted services not related to construction including engineering, design, project management, scheduling, reporting, document management, GIS services, material management, constructability reviews by Qualified Electrical Worker (QEW), staging yard leases/setup/teardown/maintenance, and permitting support throughout the entire lifecycle of a project, as well as services related to program management including long term planning and risk assessment.
5. Other – estimated costs associated with indirect capital costs. These costs are estimated to be approximately 14.3% of direct capital costs that accumulate on a construction work order. This includes administrative pool accounts that are not directly charged to a specific project, including internal labor vacation, sick, legal, and other expenses.
6. Financing Costs – estimated costs associated with the collection of AFUDC when a construction work order remains active. Most SDG&E jobs are active for approximately 6 to 10 months from the time the job is issued to construction until it is fully completed and the collection of AFUDC charges stop.

Cost Drivers

Costs can vary significantly from project to project for a variety of reasons, including engineering and design, land rights, environmental, permitting, materials, and construction. Below is a description of these factors and why the costs can vary from project-to-project.

Engineering & Design: SDG&E collects LiDAR (Light Imaging Data and Ranging) survey data before the start of design and again after construction is completed. During the LiDAR data capture, other data including photos (i.e., ortho-rectified images of the poles and surrounding area, and oblique pole photos), and weather data is acquired. After collection of the raw LiDAR and Imagery data, it is processed to SDG&E's specification and includes feature coding and thinning of the LiDAR data, and selection and processing of the imagery data. The entire process for delivery to SDG&E's specification can take weeks to months depending on the size of the data capture. This LiDAR data capture is used to support the base-mapping, engineering, and design processes (Stage 1 and Stage 6).

Currently, the engineering and design of all covered conductor projects are conducted by engineering and design consultants, and their deliverables are reviewed by a separate Owner's Engineering (OE) consultant to ensure compliance with SDG&E standards and guidelines. At this time, SDG&E does not have the resources to conduct the engineering and design required at this scale of work; however, there is an assigned SDG&E full time engineering staff that provide oversight of all engineering and design consultants, including the OE. The engineering component of work relates to the structural analysis, including Power Line Systems – Computer Aided Drafting and Design (PLS-CADD) modeling, foundation calculations, or geotechnical studies. The design component includes the drafting, entering design units into SAP for material ordering and costing, and building the job packages that are sent to construction. In some cases, one consultant can perform both the engineering and design function, and in others cases an engineering consultant collaborates with a design consultant. In all cases, SDG&E's Owner's Engineer will perform both engineering and design review support. Costs from consultants can vary depending on the size and complexity of the project, and due to various other factors including environmental constraints, land constraints, permitting requirements, or scoping changes that can occur from the start of design and throughout construction. The design stage (i.e., start of design to issuance of job package to construction) typically takes anywhere from six months to two years depending on the size and complexity of the project and the challenges with acquisition of land rights, environmental release, and permitting.

SDG&E requires every pole be engineered using PLS-CADD software during two stages of the project lifecycle, the design phase and the post-construction phase. This software allows SDG&E to leverage LiDAR survey data (pre- and post-construction) and AutoCAD drawings, and to design the poles, wire, and anchors to meet General Order (GO) 95 Loading (Light and Heavy Loading) and Clearance Requirements, and to meet Known Local Wind requirements (e.g., 85 mph and in some cases 111 mph wind). SDG&E also requires its engineering and design contractors who use the PLS-CADD software to have a California-registered Professional Engineer oversee and stamp the final PLS-CADD design.

Land and Environmental**:** SDG&E requires all projects to go through a land and environmental review process at each stage of the design process. These processes are predominantly supported with the help of land management and environmental service consultants but are overseen by SDG&E representatives in each respective department. The land process includes research of SDG&E's land rights, interpretation, and may include support obtaining the proper land rights when required. Through the land rights review process, SDG&E determines the land ownership its facilities (e.g., poles, anchors, and wire) are within and get an interpretation of the limits of its land rights. The results are shared with the engineering and design team and environmental. Once the land rights are determined, environmental performs an assessment, determines the environmental impacts if any, and provides input to the design process to minimize and/or avoid environmental impacts. These land and environmental reviews can drive changes to the design and add time and cost to the project. For example, in many cases, SDG&E does not have the land rights to build the overhead covered conductor design within its existing easement, or in some cases it only has prescriptive rights. In those cases, SDG&E must amend or acquire the proper land rights, or redesign the project, if possible, to stay within the land and/or environmental constraints. If acquiring or amending land rights is required, this can take weeks to months depending on the property owner (e.g., private, BIA, State, Federal, or Municipality) and the level of change to the existing conditions.

Materials: SDG&E's philosophy with covered conductor, like SCE, is to install it in an open-crossarm configuration. In this configuration, the conductor is self-supporting and attached to insulators on crossarms at the structure. Where connections are necessary, piercing connectors are used to avoid stripping the wire and causing damage to the conductor and negating the need to wrap the connection with insulating tape. SDG&E also requires the use of vibration dampers, where necessary, to mitigate conductor damage due to Aeolian vibration. SDG&E replaces most wood poles to steel, and in some cases replaces existing steel poles if they are not adequate to support the new wire (e.g., inadequate clearance and/or mechanical loading capacity). In many cases equipment is replaced during these reconductor projects if it is older, is showing signs of failure, and/or needs to be brought up to current standards. The reason to replace wood poles with steel is due to several reasons, including the fact steel is more resilient to fires than wood and is seen as a defensive measure, steel is a man-made material and the strength and dimensions are consistent and have much smaller tolerances than wood, and because many of SDG&E's wood poles are over 50 years old. In some cases, SDG&E may also need to relocate the pole line to an area where it is more accessible to build and maintain but will require obtaining a new easement. SDG&E also replaces wood crossarms with fiberglass crossarms, insulators with polymer insulators, switches, and regulators. For transformers, SDG&E developed specific criteria for replacement. For example, where a transformer will be replaced if it is internally-fused regardless of age, if it's greater than 7 years old, if it has visual defects or damage (leaks, burns, corrosion, etc.), is less than 25 kVA, or if the transformer does not pass volt-drop-flicker calculation. SDG&E also replaces secondary wire that is either open (non-insulated) or "grey wire" (covered secondary wire where the insulation is grey in color). On most projects, there is a smaller underground job associated with the overhead work. This occurs when a pole feeds underground (e.g., a Cable or Riser Pole) and the new pole location may be too far from the existing position such that the existing cable, conduit, and terminations may not reach the new pole position. In these cases, a small job will be initiated to have the crews intercept the run of underground conduit, install a new handhole, install a new run of conduit and cable to the new pole location, and splice the cable in the new handhole to make the connection to the existing underground system.

In 2021, SDG&E experienced significant material supply chain issues, especially with covered conductor materials due to impacts from COVID-19. In the case of covered conductor, SDG&E currently sources the wire from multiple suppliers; however, the associated materials such as piercing connectors and piercing dead-ends come from one supplier out of Europe and experienced significant delays in getting orders delivered due COVID-19 and issues with US Customs paperwork. SDG&E also experienced delays receiving other material due to COVID-19 supply chain disruptions and competition for the same materials used by other utilities including transformers and other materials common to various utilities across the country. Material delays can cause construction delays or cause construction to work less efficiently, thus impacting project schedules and costs.

Construction: One of the most significant variables, and most difficult to predict, is the civil portion of construction. The civil portion of a project includes the pole hole and anchor hole digging and can vary significantly depending on several factors including accessibility (truck accessible versus non-truck accessible), soil conditions (rock versus soft soil), methods of digging (hand tools versus machine), and environmental constraints that may limit the method of digging or dictate access protocols. For example, a 0.7 miles project completed a couple of years ago was on the side of a steep mountain side and all the material, equipment (pneumatic drill and hand tools), and crews had to be flown in and out every day for months. The civil crews encountered significant rock at most locations and the spoils from the digging had to be flown out via helicopter due to the restrictions placed on construction due to environmental concerns rather than be spread-out on location. Each pole and anchor were back-filled with concrete using helicopters because of the slope of the mountain and due to the significant mechanical loading due to winter storms. In contrast to this mountain side project example, SDG&E has had other projects that are truck accessible, that do not require concrete backfill and allow it to reuse the spoils for backfill or spread out on location.

Another reason costs can vary significantly from project to project is due to the time of year and location. SDG&E often deals with elevated fire weather conditions which requires a dedicated fire watch crew to be present at each location where there is work happening that can be a fire risk. In some cases, SDG&E has multiple dedicated fire watch crews on a project as there may be multiple civil or electric crews working at different locations at the same time on the same project. Some locations are also so remote that the drive time from the staging yard to the site can take a significant amount of time out of each workday that the crew may work longer hours and/or over the weekend, including Sundays, thus increasing overtime hours for the construction crew and all other support services (e.g., traffic control, environmental monitors, etc.). In some cases, generators are used due to the remote nature of some customers and the lack of ties with other circuits in SDG&E's service area. Generators require special protection schemes, equipment, and resources to adequately plan, deploy, setup, monitor, and tear-down which increase the installation costs.

Lastly, construction costs can vary depending on the crew building the project and issues encountered during construction that were not anticipated during design. SDG&E currently uses four primary construction contractors who perform the electrical construction and typically sub-contract the civil work (e.g., pole hole and anchor digging), helicopter, traffic control and dedicated fire watch. SDG&E also uses internal electric construction teams who typically contract out the helicopter, traffic control, dedicated fire watch and civil work (pole hole and anchor digging). Based on SDG&E's experience with its traditional hardening program, 75% of the work is performed by contractors and 25% by internal crews. The costs between external and internal crews can vary depending on the work scope, location (rural versus very rural), methods of construction (e.g., truck accessible versus non-truck accessible), time of year (e.g., fire season and non-fire season and wet weather versus dry), and issues encountered during construction. Larger projects (typically 20 or more poles) that are not assigned to an internal crew are sent out to bid with the four prime construction contractors and often bundled together on the same circuit to gain economies of scale. SDG&E has determined that its ideal bid size is 100-200 poles; however, some bids have been significantly greater (e.g., approximately1,400 poles and over 60 projects) and some can be much smaller. The size of bids can change significantly depending on the location of a project, time of year, and schedule of the project. SDG&E also sees changes with pricing due to competition for construction resources with the other utilities in the state and this can drive-up costs depending on the volume of work and timing with other projects statewide.

PacifiCorp

CC Unit Cost Make Up

As included in its 2021 WMP Update Change Order filed November 1, 2021, PacifiCorp has historically broken down the costs of covered conductor into four main categories: Design, Materials, Construction, and Program Management. However, to better align with other utilities, and avoid confusion, for the purposes of this report, PacifiCorp reports the costs of covered conductor in the six main categories. These six categories are described below.

1. Labor (Internal): Internal labor charged directly to the project including project managers, project support staff, engineers, and field personnel.
2. Materials: All materials installed as part of covered conductor projects.

3. Contractor: Contracted services which are primarily design, estimating, permitting, vegetation management, and construction labor.
4. Overhead: Costs allocated to covered conductor projects such as surcharges for material handling and engineering overheads.
5. Other: Direct costs not covered in one of the other categories.
6. Financing Costs: AFUDC charges on the projects.

Cost Drivers

PacifiCorp has identified five main cost drivers for the installation of covered conductor. The cost drivers are discussed below in terms of cost increases that have been experienced, highlighting how impactful these components can be on the overall project cost.

Access: PacifiCorp includes costs for required access to facilitate project construction in covered conductor projects charged to the work order. These costs may include vegetation clearing, road construction, or other site preparation activities. These costs will typically be included in the contractor total for purposes of this cost analysis as this work is predominantly contracted. Additionally, these costs can also range significantly between projects based on the specific location and terrain where work is conducted.

Pole Replacement: PacifiCorp evaluates all poles for strength and clearance using PLS CADD. Poles are then selected for replacement for the following reasons: insufficient strength to accommodate covered conductor, insufficient minimum clearance, relocation is required, or not constructible in current state. Through 2021, the average pole replacement rate has ranged from 2 to 22 per mile leading to significant variability in the per mile job cost. Pole replacements also significantly impact labor and material costs (as described below) due to the change in scope of the project. Current cost forecasts assume 20 poles per mile will need to be replaced. Additionally, nearly all poles identified are replaced with non-wood fire resistant materials (predominantly fiberglass) at a greater cost than like-for-like replacement with wood.

Construction Labor: As included in its 2021 Change Order, PacifiCorp experienced significantly higher than anticipated labor costs in 2020 and 2021 based on regional contract rates, construction complexity/time, and overtime requirements to meet project deadlines. Current cost forecasts indicate that this increase will continue in 2022 and future years.

Materials: As included in the company’s 2021 Change Order, PacifiCorp also experienced additional material costs due to the number of pole replacements. Currently, incremental pole replacements add approximately $3,500 per pole in material costs alone. Additionally, supply chain constraints in 2021 resulted in the need for expedite fees, crew re-mobilization costs, and/or use of alternate materials at higher costs.

Permitting: As included in the company’s 2021 Change Order, significant cost increases have been experienced for locations requiring access into seasonal wetlands and transmission under build projects. Future projects include environmentally sensitive areas that have been in NEPA or CEQA review with high environmental review costs.

Based on the cost drivers discussed above, PacifiCorp anticipates higher costs for projects in 2022 and beyond.

BVES

CC Unit Cost Make Up

The following costs are charged to project work orders: Design, materials, construction labor and overhead cost. BVES contracts out most of the work with a BVES Field Inspector overseeing the whole project. The design consists of BVES contractor performing field visits, wind loading calculations, developing the design and assembling the material lists. BVES purchases the materials and its contractor does the construction. The overhead costs consist of BVES internal groups. The capital cost per circuit mile are based on a double circuits' area in 2021.

Cost Drivers

BVES service area is in mountainous terrain at approximately 7,000 ft elevation and consists of a 34.5 kV Delta 3-wire system and a 4.16 kV Wye ground 4-wire system. For the 34.5 kV system, 394.5 AAAC is the primary source of covered conductor and 336.4 ACSR is used as a secondary source of covered conductor. For the 4.16 kV 3-phase system, 394.5 AAAC is the primary source of covered conductor and 336.4 ACSR is used as the secondary source of covered conductor. In addition, BVES uses the 4.16 KV (2 or 1) phase system 1/0 ACSR covered conductor. When constructing covered conductor, BVES follows the CPUC's GO 95 Rule 43.1 Grade A Heavy Loading District Construction Standard (Grade A Standard). Based on the Grade A Standard, new poles are required to have a safety factor of 4.0 whereas an existing pole safety factor is 2.67. BVES and BVES's contractor are required to wind load each pole with 6lb/ft wind speed + 0.5 inches of ice. Due to the higher elevation and Grade A standard, BVES is required to replace a pole with a larger size pole to meet the required safety factor. These large poles have a much higher cost than a standard size pole. BVES replaced approximately 70% of its poles per mile of covered conductor installation. The installation and material costs of the replacement poles is one driver that has increased costs for BVES covered conductor projects.

Liberty

CC Unit Cost Make Up

Liberty's covered conductor program is relatively new and limited in scope compared to the other utilities. Liberty first piloted covered conductor projects in 2020 in select areas that already needed line upgrades because of asset age and condition, and later focused on projects that targeted short line segments in HFTD areas, had reliability issues, and were in remote areas. An average of recent covered conductor projects amounted to less than one circuit mile per project and only a total of eleven miles of covered conductor were installed over the last two years. Liberty's covered conductor work is substantially less compared to, for example, SCE's approximate 1,000 miles of covered conductor installed each year.

Liberty's covered conductor unit costs will vary depending on the terrain, number of poles replaced, type of conductor installed, project design and permitting requirements, and amount of vegetation management work required for the job order.

Liberty's covered conductor capital costs per mile is made up of the following six major cost categories:

1. Labor (internal) – Internal Labor represents Project Management, Engineering, Operations, Arborists and Line Crews dedicated to the capital job, and cost of removal.
2. Materials – Materials includes poles, crossarms, insulators, down guys, anchors, transformers, hardware, and covered conductor wire purchased through Liberty supply chain operations.
3. Contractor – Contract charges are for construction contractors and professional services to design and execute project scopes. Contract costs also include line clearance qualified tree crews needed to prune and remove trees along the covered conductor line route.

4. Overheads – Overheads are allocated to active job orders monthly based on capital spend. At Liberty, this could include indirect labor, A&G, capital overheads, fleet, and small tools allocations.
5. Other – Other is reserved for taxes applied to the job.
6. Financing Costs – Financing costs capture AFUDC accumulated costs in the covered conductor job order.

Cost Drivers

Liberty's project life cycle ranges from 18-36 months depending on project scope and permitting complexity. There are many factors that may impact the total project life cycle and costs, including permitting and environmental requirements, easements, geography and terrain, and construction resource availability. A major cost driver for Liberty is the contractor costs for construction in its service territory. Projects typically take longer to construct because of the mountainous terrain and require more costly construction methods like helicopter use, dewatering, hard rock excavation and hand digging. Other factors include permitting, weather, and environmental restrictions that will limit scheduling flexibility and reduce productivity, causing construction costs to increase.

Conductor Type: Liberty has two covered conductor designs that vary depending on project site access and terrain. These include 14.4 kV delta Aerial Spacer Cable (ACS) and tree wire solutions at this voltage level. In addition, Liberty has piloted the use of tree wire solution on its 12.5 kV grounded Wye system. Liberty selects the two different system options based on installation and maintenance considerations of the two solutions.

The ACS solution has 2 or 3 covered conductors supported by a steel messenger. The framing for ACS includes brackets that hold the messenger under tension and for the current carrying conductors at full sag, or zero tension. Installing and maintaining spacers requires a bucket truck, however, if accessibility is an issue, crews might require a Bosun Chair to access the line, adding to the costs.

The tree wire solution includes various sizes of covered wire such as a 1/0, 2/0, or 397 kcmil AAC. The ACS solution projects have installed 1/0AA wire with 1-052 AWA messenger and 1/0 AAC with 6AW messenger. Tree wire is installed with framing similar to bare conductor wire in an open-crossarm configuration for framing and installation. Tree wire is the preferred solution in areas with limited bucket truck access. Conductors are sized based on circuit load for both solutions. Wind and Ice loading are concerns in the Liberty territory, so Liberty does not utilize conductors smaller than 1/0.

Location: A vast majority of Liberty's service territory is in HFTD Tier 2 and Tier 3. In the initial phases of its covered conductor program, Liberty selected areas of its service territory based on local knowledge of the wildland/urban interface, locations of high fire threat districts, remoteness of overhead lines, and the age and condition of the infrastructure. Areas were also chosen based on their accessibility and egress options during an emergency. Most of Liberty's covered conductor projects are in Tier 2 and Tier 3 at elevations between 6,200 to 7,500 feet over rugged, rocky terrain with limited seasonal access. Projects typically utilize helicopter pole sets and crews are tasked with digging pole holes with pneumatic tools by hand versus with trucks with augers. Pole holes take days versus hours to excavate, increasing labor hours and costs.

Pole and Asset Replacements: Most of the covered conductor projects Liberty has designed and constructed have required a significant number of pole replacements per circuit mile. When replacing existing poles, Liberty uses taller and larger class poles. This is due to new loads and increased weights of the covered conductor, as well as the age of existing infrastructure. Projects include installation of poles, insulators, crossarms, anchors (rock anchors), down guys, transformers, and switches. One example is the Lily Lake covered conductor project that required 50 pole replacements for the approximately two miles of covered conductor installed. The terrain at Lily Lake is remote and characterized by massive, expansive boulder fields; making pole hole digging a very labor-intensive operation. Most of the work was conducted by hand crews and helicopters due to the remote terrain.

Economies of Scale: Compared to SCE and PG&E, that have thousands and hundreds of covered conductor circuit miles installed, Liberty has limited contract resources available during its construction period. Liberty's ratio of miles installed when compared to utilities with significantly more miles installed likely leads to higher contract costs on a per mile basis. This factor has likely contributed to Liberty's higher covered conductor cost per circuit mile.

Construction: Liberty's primary construction window is from May 1st to October 15th due to weather and TRPA (Tahoe Regional Planning Agency) dig season restrictions. The construction window also coincides with seasonal tourism, a high number of Red Flag Warning (RFW) days, and during the typical fire season that further limits construction efforts and effects costs. These restrictions also constrain resources and adds a premium on labor during construction season.

In 2021, Liberty's prime construction season was impacted by fires in Northern California. For example, the Tamarack fire in Markleeville required Liberty to utilize all internal and contract resources to respond to the fire and restore power. This was a 3- to 4-week impact where contractors working on covered conductor projects had to be re-assigned to respond to the fire. Liberty has also experienced extremely poor air quality due to area fires with Particulate Matter (PM) 2.5 > 500 ug/m^3. The poor air quality frequently interrupted construction causing increased mobilization and demobilization costs. The poor air quality impacted project schedules by approximately three to four weeks with no workdays when AQI was +500 in the Tahoe Basin. Finally, the Caldor fire forced evacuations in South Lake Tahoe, where the majority of Liberty's covered conductor projects were located further impacting construction costs.

Vegetation Management: Liberty's service territory is in a high elevation and mountainous terrain that is densely forested, averaging over one hundred trees per mile within maintenance distance of the conductor given recent 2020 LiDAR data. Vegetation management inspectors and tree crews often need to access work sites on foot while carrying tools and equipment resulting in much higher labor costs compared to typical work areas. In addition, due to the robust tree canopy in the Tahoe region, tree crew cost per circuit mile of construction has increased significantly due to SB 247 labor rate increases. Tree removals and pruning costs are unique to Liberty's service area and will increase the overall covered conductor project costs.

Next Steps

In 2022, the utilities plan to continue this sub-workstream and will further discuss and document covered conductor recorded/estimated unit costs and cost drivers as well as assemble and compare initial unit costs for alternatives. The utilities will provide an update on these efforts in their 2023-2025 WMPs.

Conclusion

This report provides descriptions of the progress of this Joint IOU effort to better understand the long-term effectiveness of covered conductor and its ability to reduce wildfire risk and PSPS impacts (and, in comparison to alternatives). The utilities have made progress on each sub-workstream and describe plans for 2022 to improve the data and analyses that have been compiled, including assessing methodologies that can be employed across all utilities to improve comparability. These efforts continue to show that covered conductor has an effectiveness between approximately 60% and 90% at reducing the drivers of wildfire risk. Additionally, the report shows covered conductor is effective at reducing the impacts of PSPS in comparison to bare conductor systems. The alternative analyses also present high-level assessments of select alternatives in comparison with covered conductor at reducing PSPS impacts. The utilities look forward to continuing these efforts in 2022 and providing an update in their 2023-2025 WMPs.

Appendix A: Covered Conductor Benchmarking Survey Results

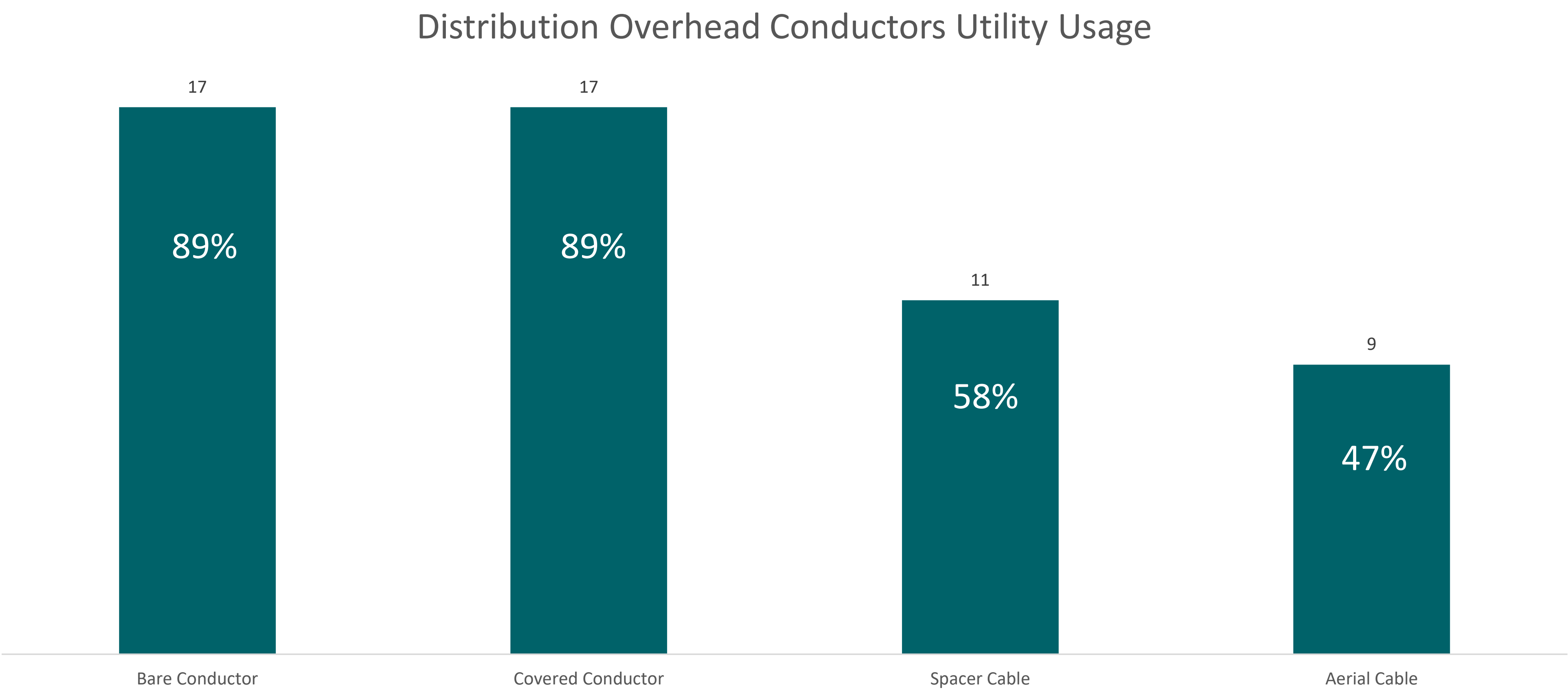
Covered Conductor Benchmarking Survey Results

Joint IOU CC Effectiveness Workstream

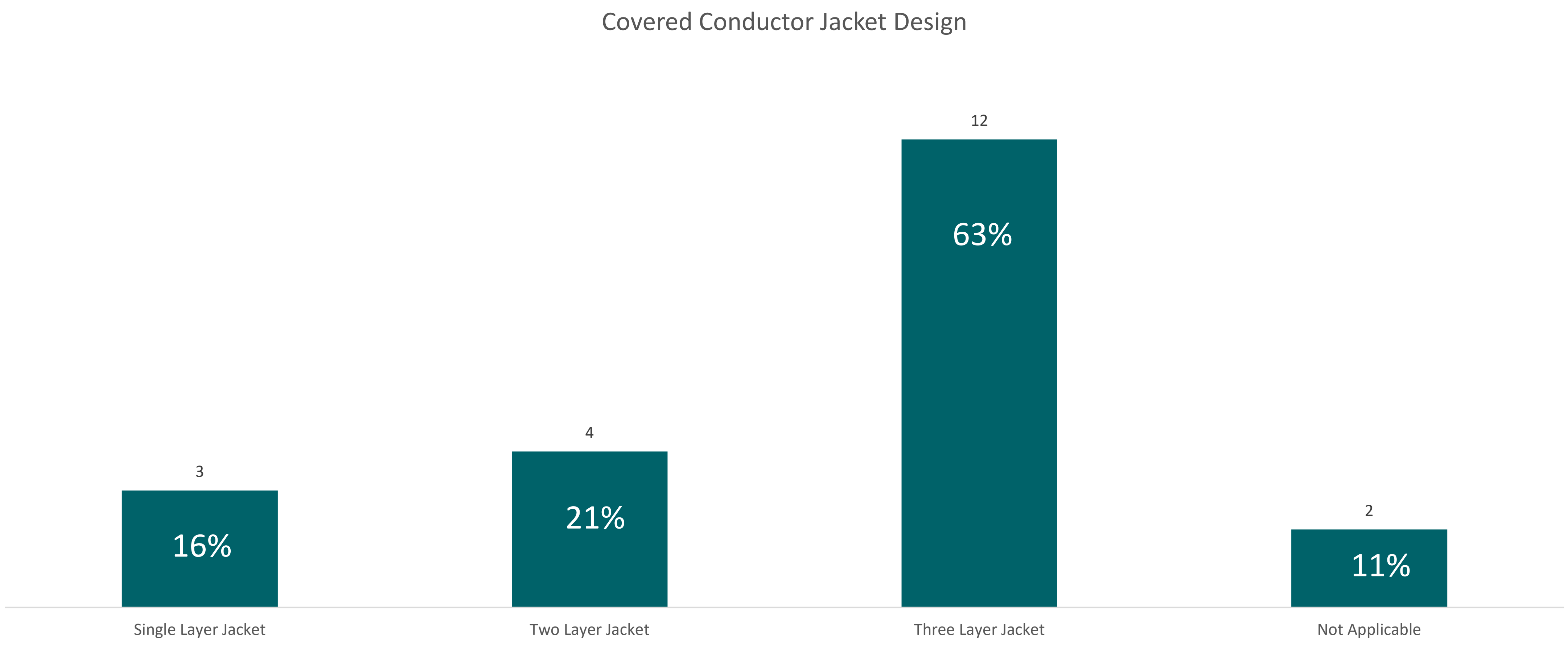
Participants

1. American Electric Power
2. Ausnet Services
3. Bear Valley Electric Service, Inc.
4. Duke Energy
5. Essential Energy
6. Eversource Energy (CT)
7. Korean Electric Power Corporation
8. Liberty
9. National Grid
10. Pacific Gas and Electric Company
11. PacifiCorp
12. Portland General
13. Powercor
14. Puget Sound Energy
15. San Diego Gas & Electric
16. Southern California Edison
17. TasNetworks
18. Tokyo Electric Power Company
19. Xcel Energy

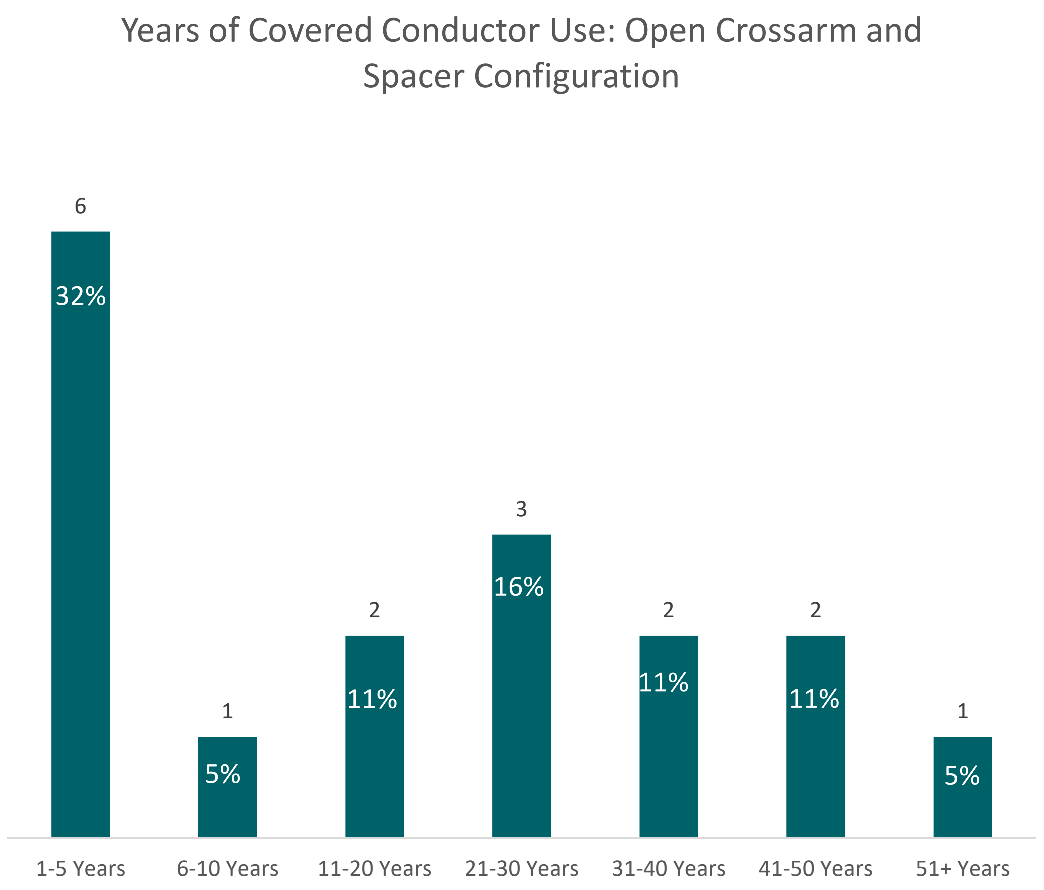
What types of overhead conductors does the utility utilize in its distribution system?

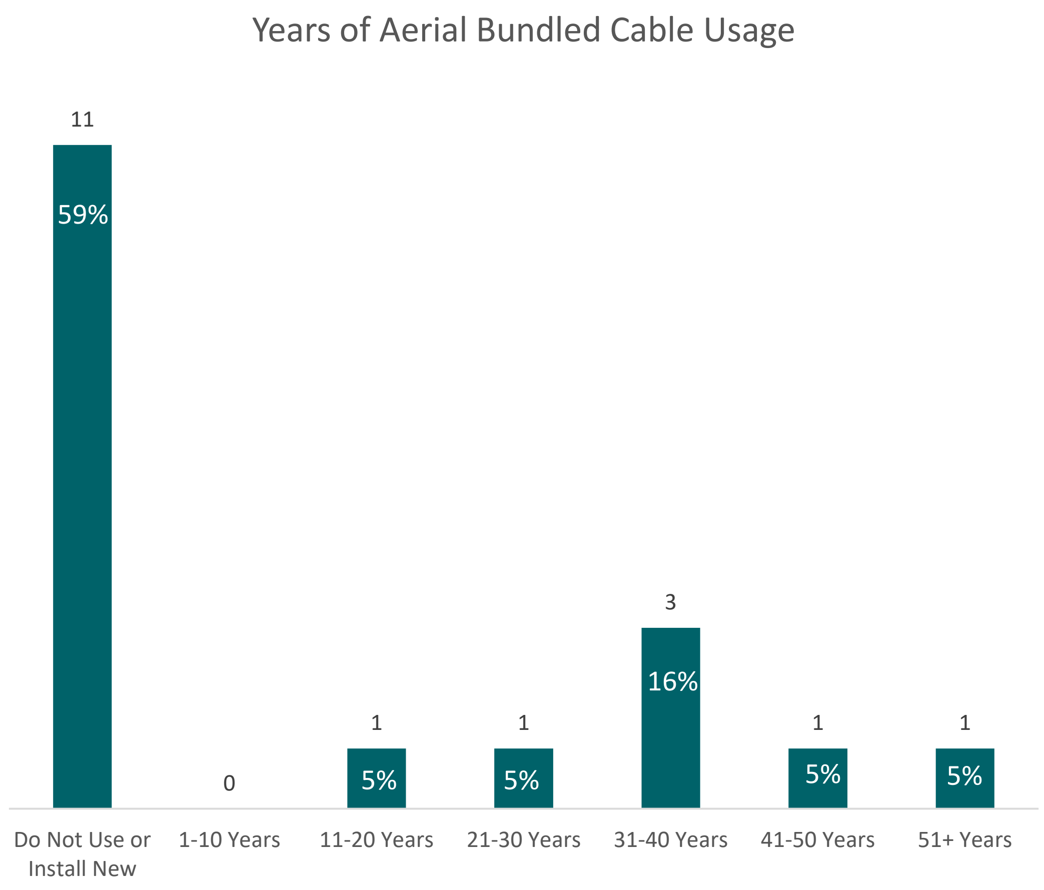


What type of covered conductor design does the utility utilize?

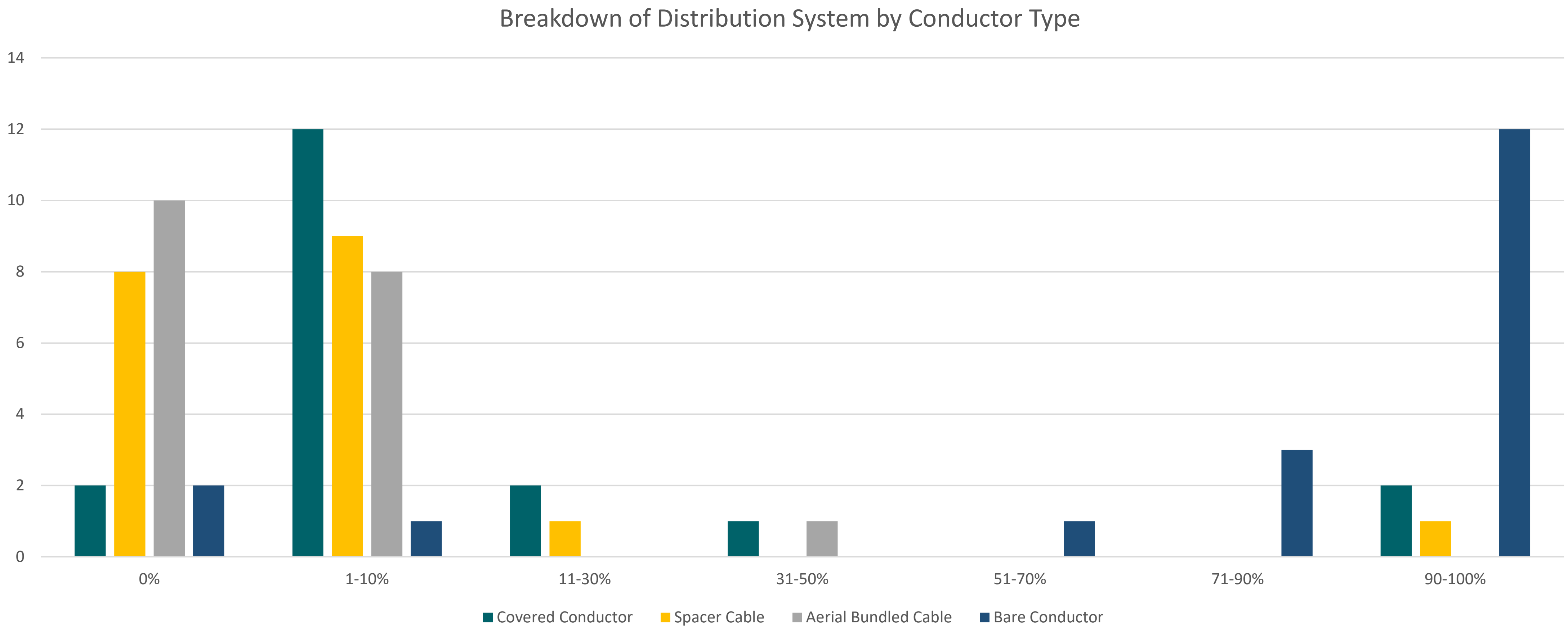


Years of Covered Conductor and Aerial Bundled Cable Usage





What percent of the primary distribution system is covered conductor vs. spacer cable vs. ABC vs. bare conductor?



Circuit Miles of Covered Conductor, Spacer Cable, and ABC Installed

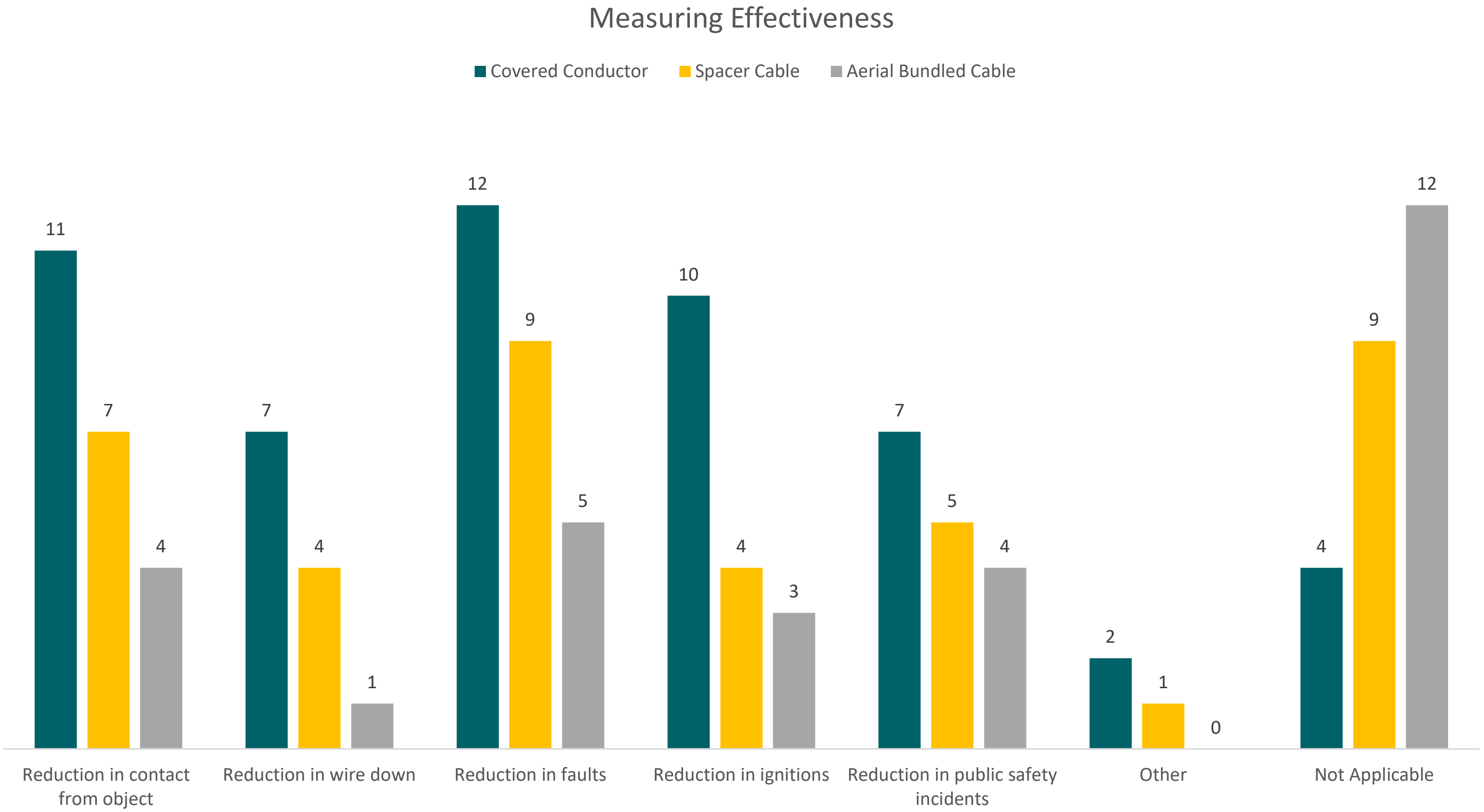
Utility	Covered Conductor Circuit Miles	Spacer Cable Circuit Miles	Aerial Bundled Cable Circuit Miles
American Electric Power	156	137	0
AusNet Services	5	25	125
Bear Valley Electric Service, Inc.	22	0	0
Duke Energy	0	0	0
Essential Energy	2,500	0	1500
Eversource Energy (CT)	8,000	520	200
Korean Electric Power Corporation[1]	120,485		
Liberty	5	2	0
National Grid	4,000	3,000	1,000
Pacific Gas and Electric Company	820	0	3
PacifiCorp	0	60	0
Portland General	243	9	0
Powercor	6	1	60
Puget Sound Energy	1,500	1	0
San Diego Gas & Electric	22	2	0
Southern California Edison	2,187	0	64
TasNetworks	2	0	10
Tokyo Electric Power Company[2]	267,190		16,156
Xcel Energy	0	50	0

1. Korean Electric Power Corporation uses Covered Conductor and Aerial Bundled Cable. Value represents total circuit miles of Covered Conductor and Aerial Bundled Cable. Circuit mile data is based on information provided from previous benchmarking
2. Tokyo Electric Power Corporation uses Covered Conductor and Spacer Cable. Value represents total circuit miles of Covered Conductor and Spacer Cable.

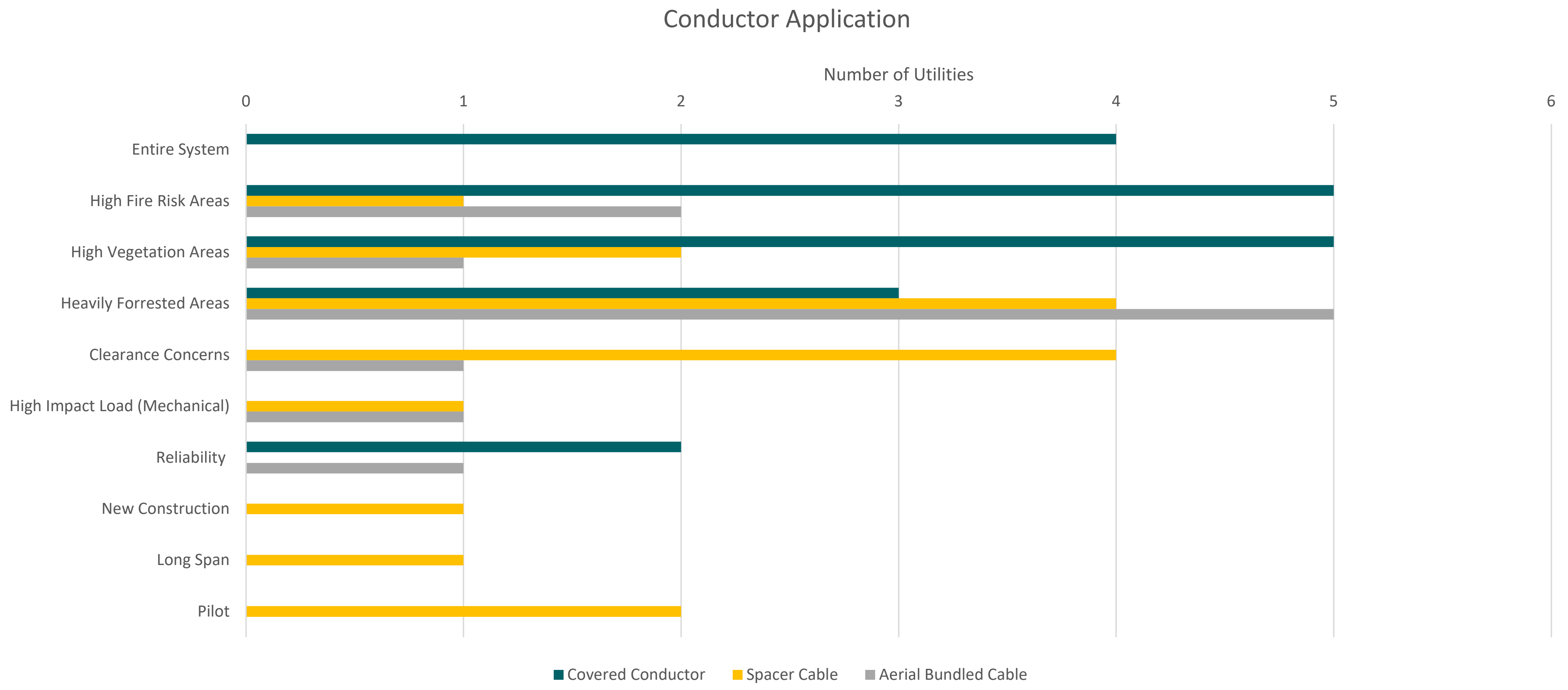
Outage and Ignition Tracking

Utility[1]	Track Outage Counts for Bare vs. CC?	Has use of CC, Spacer Cable, or ABC reduced faults?	Track ignition Counts for Bare vs. CC?	Has use of CC, Spacer Cable, or ABC reduced ignitions/ignition drivers?	If no ignition reduction, why?
American Electric Power	No	Yes	No	Yes	
AusNet Services	No	Yes	No	Yes	
Bear Valley Electric Service, Inc.	Yes	Yes	Yes	No	No prior ignitions
Duke Energy	NA	NA	NA	NA	Does not use CC
Essential Energy	Yes	Yes	Yes	Yes	
Eversource Energy (CT)	Yes	Yes	No	No	Data not tracked
Korean Electric Power Corporation	Yes	Yes	No	Yes	
Liberty	No	No	No	No	Data not tracked
National Grid	Yes	Yes	No	No	Data not tracked
Pacific Gas and Electric Company	No	Yes	No	No	Data not tracked
PacifiCorp	Yes	Yes	Yes	Yes	
Portland General	No	Yes	No	No	Data not tracked
Powercor	No	No	No	Yes	
Puget Sound Energy	No	Yes	No	No	Data not tracked
San Diego Gas & Electric	Yes	Yes	Yes	Yes	
Southern California Edison	Yes	Yes	Yes	Yes	
TasNetworks	No	Yes	Yes	Yes	
Tokyo Electric Power Company	No	Yes	No	Yes	
Xcel Energy	No	Yes	No	No	Data not tracked

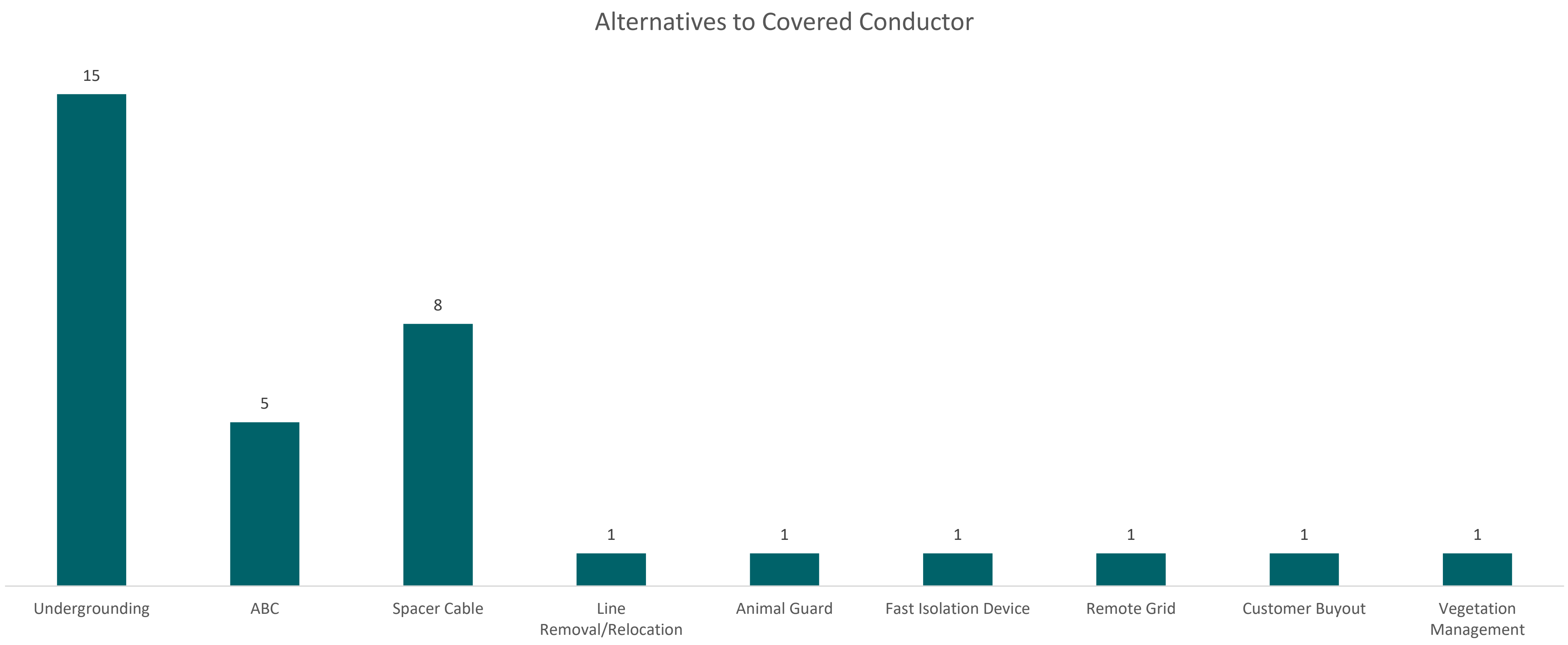
Measuring Effectiveness of Covered Conductor, Spacer Cable, and ABC



Covered Conductor, Spacer Cable, and Aerial Bundled Cable Application



Alternatives



Protection

- **Existing** fault detection methodologies
  - Overcurrent protection
    - Circuit breaker & Relay
    - Fuses
    - Reclosers
    - TripSavers
  - SCADA connected devices
  - Smart Meters
  - High voltage DC pulse with directional tracking
  - High impedance fault detection
  - Distribution automation system monitoring
  - Distance to fault algorithm

- **Potential** fault detection methodologies
  - Early Fault/Failure Detection
  - Distribution Fault Anticipation
  - Open Phase Detection
  - High impedance fault detection
  - Sensitive Ground Fault
  - Rapid Earth Fault Current Limiter
  - Downed Conductor Detection
  - LR controllers
  - Fault indicators
  - Sensing insulators
  - Zero phase voltage measurement
  - AMI meter loss of voltage detection
  - Working with vendors to develop communication aided protection to detect faulted or broken CC
  - Inspection

Patrol Protocols

- Patrol conductors after storm before energization
  - Require visual observation
  - Same as bare conductor
- Drone usage

Other Comments

Utility	Comment
SDG&E	Primarily using covered conductor, but have the option for spacer cable.
PacifiCorp	Spacer cable has been highly effective
Liberty	Piloting on a case-by-case basis, targeting highest-risk areas, based on Risk-Based Decision model.
Duke Energy	Installed covered conductor and spacer cable on our system in the past. There is a miniscule amount on our system. Our current construction standards do not call for covered or spacer cable installation for the following reasons: 1) Require additional installation procedures and maintenance compared to bare conductors. 2) Require proper Installation to prevent BIL and deterioration failures. 3) Designed to prevent intermittent vegetation contact. Should NOT be used for sustained contact of vegetation. 4) Must coincide with continual Vegetation Maintenance.
Xcel Energy	Using a strengthened neutral shield wire to protect crossarm construction from tree impacts.
TEPCO	• Use of bare wires for MV line is prohibited in Japan. For MV line, covered electric wires are basically used. • Spacer cables used when it is necessary to move the electric wire position away or change routes between utility poles. • Aerial bundled cables are used when connecting the MV line of the third route on the utility pole.
Portland General	• Developing the application strategy to mitigate wildfire in high-risk zones using these conductor types. Until now, these systems were primarily used for reliability purposes.

Appendix B: Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review

Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review

Exponent®

Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review

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Contents

Executive Summary

Exponent, Inc. (Exponent) was jointly retained by the California investor-owned utilities (IOUs) to assess the effectiveness and reliability of covered conductors (CCs) for overhead distribution system hardening. Our investigation included a literature review, discussions with subject matter experts, a failure mode identification workshop, and a gap analysis comparing expected failure modes to currently available test and field data. Based on our investigation to date, we offer the following conclusions:

1. Covered conductors are a mature technology (in use since the 1970s) and have the potential to mitigate several safety, reliability, and wildfire risks inherent to bare conductors. This is due to the reduced vulnerability to arcing/faults afforded by the multi-layered polymeric insulating sheath material.

2. A subject matter expert workshop, composed of six California IOUs and Exponent, was conducted, and identified hazards and failure modes affecting bare conductors and CCs. Of the 10 hazards that affect bare conductors, CCs have the potential to mitigate six. Mitigated hazards include tree/vegetation contact, wind-induced contact (such as conductor slapping), third-party damage, animal-related damage, public/worker impact, and moisture.

3. The primary failure mode of bare conductors is arcing due to external contact. Laboratory studies and field experience have shown that arcing due to external contact was largely mitigated with CCs. Therefore, a corresponding reduction in ignition potential would be expected.

4. Field experience from around the world, including North America, South America, Europe, Asia, and Australia, consistently report improvements in reliability, decreases in public safety incidents, and decreases in wildfire-related events that correlate with increased conversion to CC.

5. While high-level field experience–based evidence of CC effectiveness is plentiful, relatively few lab-based studies exist that address specific failure modes or quantify risk reduction relative to bare conductors. For some failure modes, further testing is recommended to bolster industry knowledge and to enable more effective risk assessment.

6. 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, etc.).

Note that this Executive Summary does not contain all of Exponent's technical evaluations, analyses, conclusions, and recommendations. Hence, the main body of this report is at all times the controlling document.

Motivation and Scope

California investor-owned utilities (IOUs) Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) engaged Exponent to summarize the effectiveness of CCs for hardening of overhead distribution electric lines. During the project, three additional California IOUs joined the effort: Liberty, PacifiCorp, and Bear Valley Electric Service. CCs have gained industry attention due to their potential for mitigating risks associated with public safety, reliability, and wildfire ignition. The current study was undertaken to better understand the advantages, operative failure modes, and current state of knowledge regarding CCs. The objectives of this study were to:

1. Summarize the effectiveness of CCs.
2. Summarize the implementation and design considerations of CCs.
3. Identify gaps in current testing/knowledge and practices/implementation.

To meet these objectives, we performed a comprehensive review of publicly available literature, utility-provided data, and manufacturer information. Additionally, a high-level failure mode identification workshop was conducted with input from technical subject matter experts representing the California IOUs and Exponent. The workshop output was compared against the available literature and test data to identify any gaps between the current state of knowledge and the identified failure modes.

Covered Conductor Technology

History and Motivation for Development

The term “covered conductor” refers to a variety of conductor cable designs that incorporate an external polymer sheath to protect against incidental contact with other conductors or grounded objects such as tree branches. This technology has several advantages over traditional bare conductors, and the key drivers for adoption have been to improve overall system reliability, to enhance public safety in high-population areas, to decrease required right-of-way in densely forested areas, to decrease the scope and frequency of vegetation management, and to reduce the probability of ignition from conductor heating/arcing in fire-prone areas.

Construction and Types

CCs were first adopted in the United States and Europe in the 1970s for medium-voltage distribution lines (35 kV and below) and were later implemented for high-voltage overhead lines in the 1990s [Leskinen 2004]. Early iterations had various technical challenges that led to the development of the modern CC design that will be discussed throughout this report. Modern CCs consist of an all-aluminum conductor (AAC), aluminum conductor with steel reinforcement (ACSR), or copper (CU) conductor, enclosed in a multi-layer polymer sheath. The number of layers and their composition largely depend on the specified voltage rating, as multi-layered variants have a higher impulse strength than the single-layer design and often include a semiconducting conductor shield. This report focuses on CC use in the “medium voltage” range (6–35 kV), though the technology can also be used for higher or lower voltage.

Figure 1 shows a three-layer CC design, which is commonly used for distribution-level voltages. A high-density polyethylene (HDPE) outer jacket provides strength, abrasion resistance, and weather resistance. This layer may be cross-linked to increase its high temperature strength and dimensional stability. A low-density polyethylene (LDPE) inner jacket provides dielectric strength to protect the underlying conductor and may also be cross-linked to enhance high temperature properties. Finally, a semiconducting thermoset “shield” layer is wrapped around the conductor, which equalizes the electric field around the conductor to reduce voltage stress and preserve the insulation [Wareing 2005].

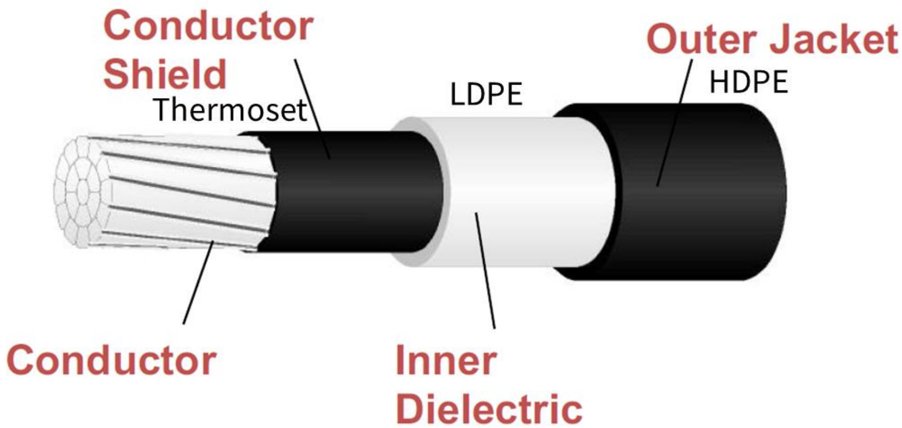

Figure 1. A schematic illustration of a three-layer CC. Diagram modified from Hendrix Aerial Cable Systems [Trager].

Overhead Configurations

One common configuration for CCs used in overhead distribution systems is the standard crossarm-mounted construction. This configuration, sometimes referred to as “tree wire,” is often seen where CCs are installed on pre-existing infrastructure designed for bare conductors. This method can leverage legacy hardware, construction and maintenance practices, and pole structures if the weight, diameter, and modified tensioning are considered. Conductors are typically attached to polyethylene pin-type insulators in this configuration. A reduced crossarm structure can also be used in narrow rights-of-way. One disadvantage to this method of installation is that it requires stripping of the conductor sheath at dead-end attachments, creating a length of unprotected bare conductor. Figure 2 shows an example of tree wire construction.

Figure 2. An example of crossarm-mounted CC, or “tree wire,” construction. Photo from Hendrix Aerial Cable Systems [Trager].

CCs are also often constructed in a “spacer cable” configuration. Spacer cable takes advantage of the reduced clearance required of CCs by closely spacing adjacent conductor phases with rigid spacer hardware. This configuration is advantageous in tight corridors where right-of-way may be limited and can reduce wind-related impact on individual conductors [Trager]. No stripping of the conductor sheath is required for this installation method, resulting in a completely covered system except for tap, transformer/capacitor, surge arrester, and protective device locations. A notable feature of spacer cable is that the conductor is not self-supporting, but rather, a steel cable or “messenger cable” is used to support multiple conductors. The messenger cable can also shield the conductors somewhat from fallen branches and lightning strikes. Figure 3 shows an example of spacer cable construction.

Figure 3. An example of spacer cable CC construction. Photo from Hendrix Aerial Cable Systems [Trager].

Field Experience

Finland

Finland started adopting CCs for medium-voltage lines in the 1970s and high-voltage lines in the 1990s to increase reliability. While only 4% of the total medium-voltage network, CCs accounted for 90% of the total average medium-voltage length increase during the early 2000s [Leskinen 2004].

The annual outage rate per 100 km from Finland is shown in Figure 4 and is valid for rural areas. As the figure shows, the number of faults has steadily decreased since the 1970s to around five faults per 100 km. This likely corresponds to the increased number of CC lines in the network [Leskinen 2004].

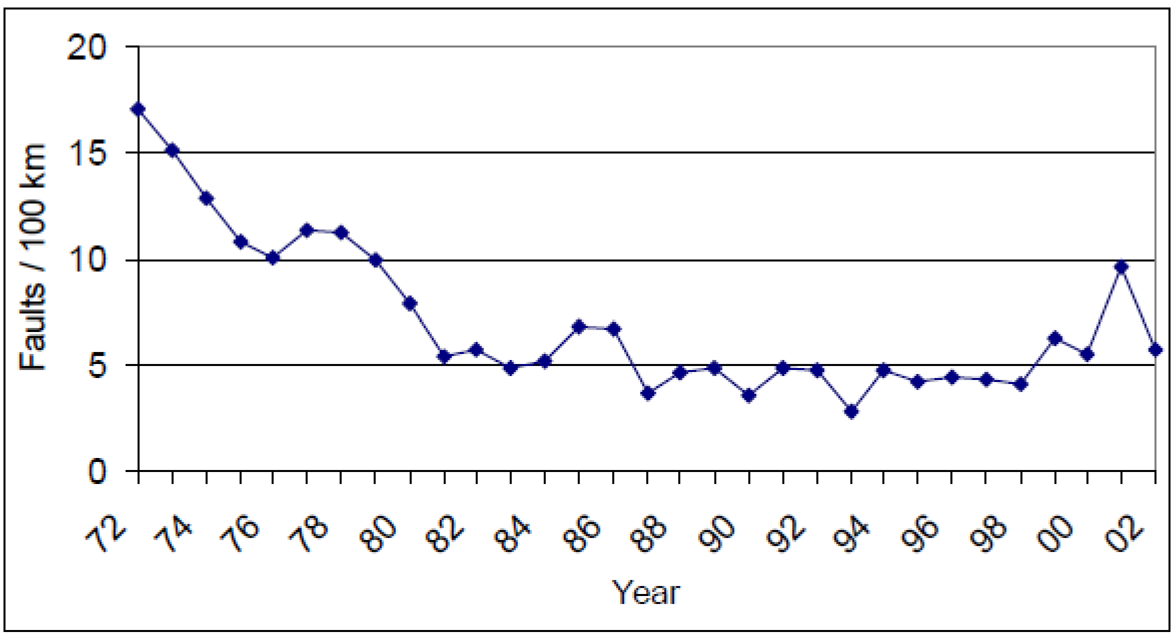

Figure 4. Annual number of faults per 100 km in rural areas of Finland from 1972 to 2002 for medium-voltage lines. Image from [Leskinen 2004].

This study also analyzed previous literature that suggested CC installation also affects the number of high-speed and delayed automatic reclosings. Based on the field data-derived empirical equations from Heine, *et. al*., as shown in Figure 5, the number of high-speed autoreclosings decreases by one third when the percentage of CC lines increases from 10% to 50% [Heine 2003, Leskinen 2004]. The number of autoreclosings is indicative of the number of faults; therefore, these data suggest that the number of faults decreased with increased use of CCs. More recent studies show that the number of permanent faults in CC lines is 20% of the number associated with bare conductor overhead lines and gives an annual fault number of one per 100 km [Leskinen 2004].

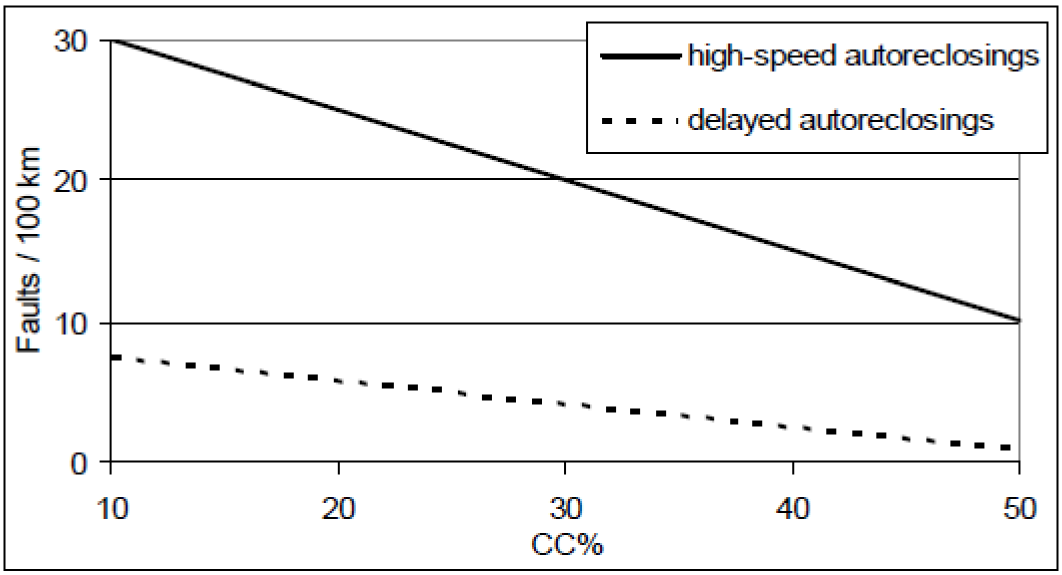

Figure 5. Fault frequency as a function of CC network share in Finland. Image from [Leskinen 2004].

Slovenia

The Slovenian utility Elektro Ljubljana began building CC lines in 1993 to improve reliability, and within ten years CC lines comprised 8% of all Slovenian medium-voltage overhead lines [Leskinen 2004]. The annual medium-voltage outage rate in rural Slovenia was between 15 and 25 per 100 km prior to the introduction of CCs. After the adoption of CC lines and other new technology such as remote-controlled load breakers and shunt circuit breakers, the annual outage rate reduced to less than two faults per 100 km. This rate is nearly double the most recent annual outage rate of Finland, as discussed in the prior section. The higher fault rate in Slovenia compared to Finland has been attributed to the higher level of lightning and a lack of standards [Leskinen 2004].

Taiwan

The Taiwan Power Company invested the equivalent of over $360 million between 1996 and 2000 to replace 11.4 kV overhead lines with 15 kV cross-linked polyethylene (XLPE) weatherproof wires (a type of CC) [Li 2010]. Figure 6 shows the impact of CC lines on the Taiwan Power Company distribution system. (The ratio of covered line length using XLPE weatherproof wire in the distribution system to the total line length of the system is given by the variable r_c.) The distribution system reliability is assessed using the system average interruption frequency index (SAIFI) and the system average interruption duration index (SAIDI). Figure 6 shows the variation of r_c, SAIFI, and SAIDI during 1985 to 2005. Installation of CC lines from 1985 to 2005 resulted in lower fault frequency and interruption duration.

As distribution systems in Taiwan are near highly populated areas, endangered-life indices (ELIs) were used for statistical data with regard to people who experience electric shocks. The following ELI values were used: the annual number of people who receive electric shocks (N_p), the annual number of people injured by electric shocks (N_{pi}), and the annual number of people electrocuted (N_{pe}). The ELI rates and r_c values from 1985 to 2005 are shown in Figure 6. As r_c increased, all ELIs decreased annually from 1995 to 2005 as more CC lines were incorporated into the distribution system.

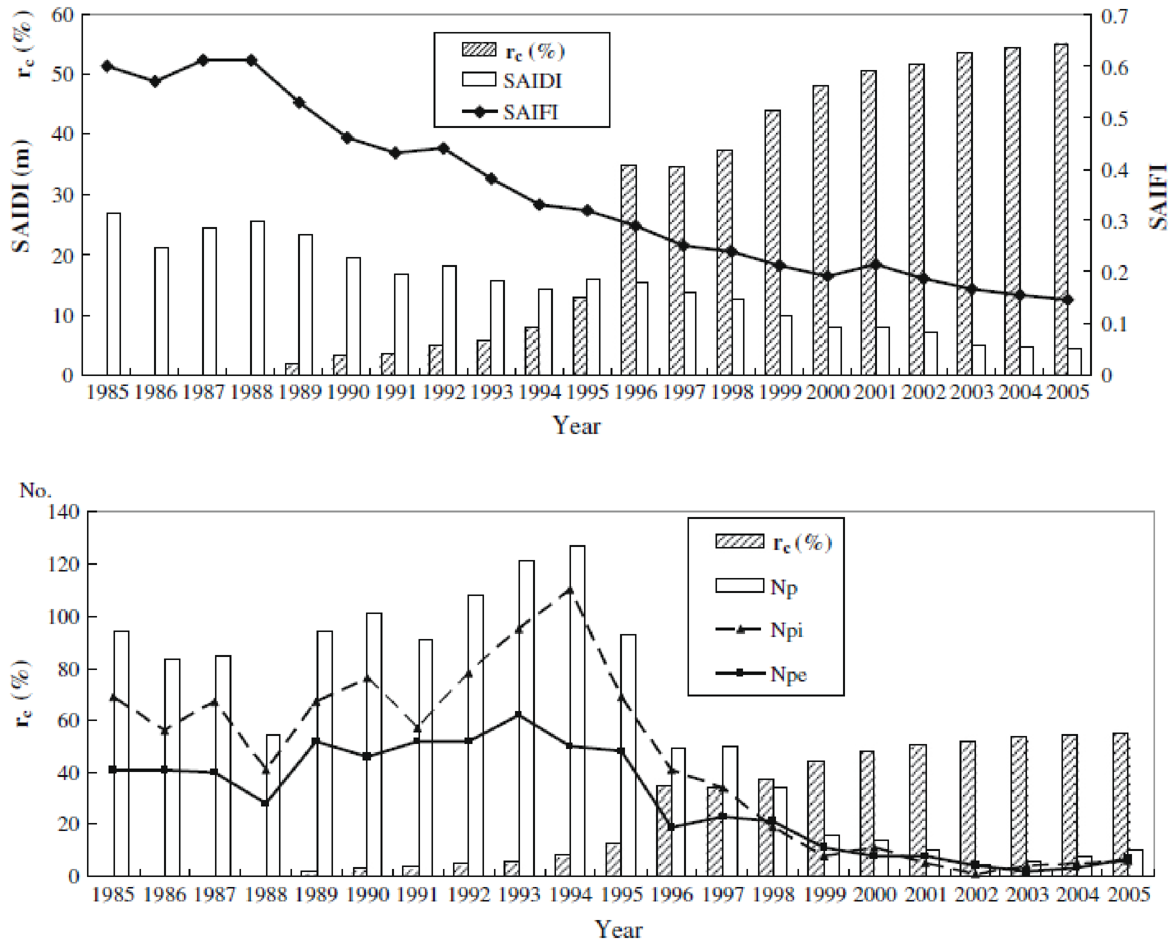

Figure 6. (Top) Taiwan Power Company results from 1985 to 2005 for the ratio of covered line length using XLPE weatherproof wire in a distribution system to the total line length of the system (r_c), system average interruption frequency index (SAIFI), and the system average interruption duration index (SAIDI). (Bottom) Taiwan Power Company results from 1985 to 2005 r_c and endangered-life indices (ELIs). The following ELI values are shown: annual number of people who receive electric shocks (N_p), annual number of people injured by electric shocks (N_{pi}), and annual number of people electrocuted (N_{pe}). Image from [Li 2010].

Australia

CCs have been used in Australia for more than 50 years, primarily motivated by wildfire risk reduction. Early CCs had limited lifetimes due to surface degradation, tracking, radio frequency (RF) emissions, and lightning damage [Wareing 2005]. In the mid-2000s, the Australian Strategic Technology Program determined that technological advancements may help solve historical issues with CCs to allow for their widespread adoption. After the Black Saturday bushfires, the Victorian Bushfires Royal Commission (VBRC) recommended the existing power lines be replaced with aerial bundled cables or other technology that reduced the risk of bushfires. The VBRC estimated a 90% reduction in the likelihood of a bushfire starting by installing CCs [SCE 2019]. Additionally, a study by the Commonwealth Scientific and Industrial Research Organization (CSIRO) found that a 98% reduction in the risk of bush fires due to CCs could be expected [SCE 2019, Electrical Connection 2021]. Although it is unclear how these specific metrics were determined, this shows high confidence by the VBRC and the CSIRO in the effectiveness of CC for wildfire mitigation.

Malaysia

The Tengag Nasional Berhad (TNB) distribution network in Malaysia includes 5,300 km of 33 kV, 22 kV, and 11 kV medium-voltage bare overhead conductor lines and 2,700 km of 33 kV and 11 kV medium-voltage aerial-bundled cables (ABC) lines [Ariffin 2012]. Malaysia has reliability challenges caused by above-average lightning activity, small-animal damage, and vegetation damage, which motivated the use of CCs to improve reliability. TNB started installing medium-voltage ABC lines in the 1990s. Early versions of ABCs had inferior fault rates and failed to deliver on the expected benefits. A redesign was undertaken to change from the single-layer copper screen with HDPE outer sheath to a double-layer copper screen. Additionally, improved construction standards were followed, and compatible accessories were used that resulted in improved performance.

TNB found that the medium-voltage bare conductor lines had a higher number of recorded failures compared with medium-voltage ABC lines from 2001 to 2007. The newly designed medium-voltage ABCs had a failure rate five times lower than that of the original medium-voltage ABCs used in the Malaysian system. In this study, a specific definition for the word “failure” was not provided.

Brazil

CEMIG, one of the four biggest power companies in Brazil, adopted spacer cables in urban areas starting in 1998 to improve reliability [Rocha 2000]. CEMIG's annual work plan was to rebuild the urban distribution system by building 1,400 km of medium-voltage lines and 2,800 km of low-voltage lines using spacer cables. CEMIG completed periodic field inspections during the first nine years of energizing the initial pilot lines. The following observations were made during the field inspections:

- Outages due to atmospheric discharges were observed where the cables had been peeled to create a metallic tie. Changes were made to how ties, polymeric rings, and polymeric anchoring clamps were installed, which resulted in improved performance.
- In areas with permanent tree contact, no signs of electrical tracking were observed.
- Minimal outages were observed in areas with vandalism (insulator breakage) and pole collisions. No outages were recorded on spacer cable lines with vandalism incidents, whereas four to five outages occurred on bare cable lines.
- Outages caused by material failures were practically eliminated.

Overall, CEMIG found a 33% reduction in the average duration and frequency of outages per customer due to the expansion of spacer cable lines [Nishimura 2001].

Failure Modes and Effectiveness

Failure Modes

A high-level failure mode identification workshop was conducted to identify operative failure modes relevant to overhead distribution systems for both bare conductors and CCs. The list of failure modes was developed during a day-long workshop with technical subject matter experts representing Exponent, PG&E, SCE, SDG&E, PacifiCorp, Liberty, and Bear Valley Electric Service. This exercise leveraged the technical knowledge from the seven different organizations and the combined experience and shared operator experiences from the six utilities. This workshop was not a full risk assessment, as other factors such as severity / consequence of an event, likelihood, and ability to detect each failure mode were outside the scope of this exercise.

The output of the failure mode workshop was a list of failure modes applicable to bare conductors and/or CCs and is presented in Table 1. The failure modes are organized into three descriptive categories: external events, human factors, and operations/maintenance. Each line item is further differentiated by the operative hazard within each category. External events primarily include hazards related to weather, vegetation, or fire. Human factors include human-induced hazards such as vehicle/equipment contact, gunshots, and Mylar balloons. The operations/maintenance category encompasses hazards related to the design, installation, and maintenance of overhead distribution lines. Within each hazard, specific scenarios that can result in failure are listed. For example, a phase-to-phase fault (failure mode) resulting from a Mylar balloon (hazard) is differentiated from a phase-to-phase fault (failure mode) resulting from a fallen tree branch (hazard). Failure modes that apply to bare conductors but are largely mitigated by using CCs are marked with a green checkmark.

Table 1. List of failure modes for bare and covered conductors.

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
External Events	Fire	External fire (wildfire)		X	1	Potential damage to sheath, reducing effectiveness
				X	2	Potential flammability of CC sheath
			X	X	3	Annealing of metal conductor due to fire exposure
External Events	Extreme heat	Extreme temperatures cause sag and clearance issues	X	✓	4	Phase-to-phase or phase-to-ground fault
External Events	UV exposure / solar exposure	Aging / exposure of conductor covering		X	5	Embrittlement and/or cracking of conductor covering
External Events	Sheath contamination	Moisture / salt contamination		X	6	Tracking/insulation failure due to moisture/salt (corona)
		Smoke during fire		X	7	Tracking/insulation failure due to smoke/ash
External Events	Ice/snow	Mechanical loading / stress on conductors	X	X	8	Excessive mechanical loading leading to conductor failure/wire down
		Unloading / dynamic shedding of ice	X	X	9	Dynamic forces leading to conductor failure and wire down
		Combined wind/ice	X	X	10	Galloping (see wind hazard)
External Events	Lightning	Atmospheric lightning	X*	X	11	Arc damage / melting of conductor, possible wire down. Short circuit duty exceeds conductor damage curve.
External Events	Animal	Animal contact		X	12	Phase-to-phase fault due to animal-damaged sheath (chewing)
				X	13	Bird dropping degradation of polymer sheath
			X	✓	14	Large bird contact of multiple conductors (phase-to-phase)

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
External Events	Moisture	Moisture/salt/ oceanic exposure	X	✓	15	Atmospheric corrosion of span leading to decreased mechanical strength or increased electrical resistance
			X	X	16	Atmospheric corrosion near hardware/dead-end leading to decreased mechanical strength or increased electrical resistance
				X	17	Freeze/thaw cycles leading to sheath damage
			X	X	18	Lack of corrosion inhibitors (on splices) leading to corrosion
				X	19	Migration of water within the sheath layer
			X	✓	20	Stress corrosion cracking of span
			X	X	21	Stress corrosion cracking near hardware/dead-end
External Events	Wind	Winds (within the natural frequency of structure)	X	X	22	Aeolian vibration-induced fatigue cracking
			X	X	23	Mechanical overload of tie wire during galloping (ice/ or lashing of spacer /messenger wires)
			X	X	24	Swinging leading to wear
			X	X	25	Vortex shedding impact / contact of adjacent conductors leading to fatigue of downstream conductors
			X	✓	26	Line slapping (intermittent conductor contact)
		Transmission / distribution line contact	X	✓	27	Differential wind-driven blowout leading to contact of distribution / transmission lines
		Pole damage		X	28	Damage due to potential for increased loading when new covered conductors replace existing bare conductors on the same poles / crossarms / guys

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
External Events	Tree damage	Tree falls, breaks conductor	X	✓	29	Conductor failure / wire down resulting in loss of service, potential for ignition (along the entire length of bare conductor or exposed section of CC)
			X	X	30	Live conductor down with no outage
		Tree branch bridges various lines (conductors do not break)	X	✓	31	Phase-to-phase fault, potential ignition
			X	X	32	Delayed fault due to long-term contact (dielectric breakdown / reduction in dielectric strength), potential phase-to-phase fault
				X	33	Abrasion of sheath
				X	34	Cracking of CC sheath
				X	35	Heating damage to sheath
				X	36	Corrosion of conductor due to compromised sheath
		Tree falls and pulls entire system to ground	X	X	37	Surrounding structure fails (broken conductor)
			X	X	38	Surrounding structure fails (conductor intact)
Human Factors	Public/worker impact	Agricultural equipment / third-party workers / under-build workers (cable/telephone)	X	✓	39	Potential for shock or electrocution
		Vehicle impact to pole / guy wire	X	✓	40	Potential for guy wire whip to create contact to conductor
			X	✓	41	Phase-to-phase contact
			X	✓	42	Phase-to-ground contact
		Gunshots	X	X	43	Conductor damage

Category	Hazard	Scenario	Bare	Covered	#	Failure Mode
Human Factors	Third-party damage	Tarps under high wind conditions	X	✓	44	Phase-to-phase contact
		Balloons	X	✓	45	Phase-to-phase contact
		Kites	X	✓	46	Phase-to-phase contact
		Palm fronds	X	✓	47	Phase-to-phase contact
Operations & Maintenance	Maintenance / Installation	Conductor damage due to incorrect hardware tool or incorrect stripping		X	48	Mechanical damage to sheath (dent/gouge)
		Poor splicing or poor connection	X	X	49	Poor contact leading to localized heating and connection failure
		Over-tensioning	X	X	50	Incorrect tensioning leading to conductor failure (due to vibration, increased stress)
		Under-tensioning	X	X	51	Increased sway leading to wear
			X	✓	52	Clearance issues due to increased sway
		Excessive angles	X	X	53	Insulator breaks off due to mechanical overload (for excessive angles). Conductor may break off or float, contacting pole.
		Broken tie wires	X	X	54	Poorly installed tie wires could break, leading to conductors separating from insulators and contacting pole.
		Improper installation	X	X	55	Bird caging—conductor strands separate

* Direct lightning strikes resulting in concentrated heating of the bare conductor and a wire down event are relatively infrequent.

Effectiveness of Covered Conductors

Failure Mode Discussion

In total, 58 unique failure mode / hazard scenario combinations were identified through the failure mode workshop. These failure modes can be categorized into three basic types:

1. Failure modes that affect both bare *and* CCs.

    Example: Aeolian vibration-induced fatigue cracking of the metal conductor (Table 1, No. 23).
2. Failure modes that affect bare conductors but are reduced or effectively eliminated by CCs.

    Example: Phase-to-phase fault due to tree branch bridging conductor phases (Table 1, No. 32).
3. Failure modes that are unique to CCs that do *not* affect bare conductors.

    Example: Lightning-induced melting of conductor sheath (Table 1, No. 12).

Failure modes that apply to bare and covered conductors

Failure modes that apply to both bare and covered conductors are well known due to historic use of bare conductors and are generally expected to be effectively managed through existing mitigations and controls. However, there are instances in which these failure modes may be *more* prevalent with CCs than with bare conductors. For instance, some wind-related phenomena such as Aeolian vibration may, in certain circumstances, be exacerbated with CCs due to their smooth surface, increased weight, and larger overall diameter [Leskinen 2004]. For similar reasons, CCs may also be more prone to ice loading than bare conductors. Ice loading may result in mechanical overload of the conductor, or increased susceptibility to galloping. A full list of failure modes that apply to both bare and covered conductors derived from the failure mode workshop is given in Table 2.

Table 2. Failure modes that affect both bare and covered conductors.

Hazard	#	Failure Mode	<u>Potential</u> risk relative to bare
Fire	3	Annealing of metal conductor due to fire exposure	Reduced
Ice/snow	8	Excessive mechanical loading leading to conductor failure / wire down	Increased
	9	Dynamic forces (ice shedding) leading to conductor failure and wire down	Needs study
	10	Galloping damage (see wind scenario)	Needs study
Lightning	11	Arc damage / melting of conductor, possible wire down	Increased
Moisture	16	Atmospheric corrosion near hardware/dead-end leading to decreased mechanical strength or increased electrical resistance	Comparable
	18	Lack of corrosion inhibitors (on splices) leading to corrosion	Comparable
	21	Stress corrosion cracking near hardware/dead-end	Comparable
Wind	22	Aeolian vibration induced fatigue cracking	Needs study
	23	Mechanical overload of tie wire during galloping (ice/ or lashing of spacer /messenger wires)	Needs study
	24	Swinging leading to wear	Increased
	25	Vortex shedding impact / contact of adjacent conductors leading to fatigue of downstream conductors	Needs study
Tree damage	30	Live conductor down with no outage	Increased
	32	Delayed fault due to long-term contact	Reduced
	37	Surrounding structure fails (broken conductor)	Needs study
	38	Surrounding structure fails (conductor intact)	Needs study
Third-party damage	43	Conductor damage from gunshot	Comparable
Maintenance/ installation	49	Poor contact leading to localized heating and connection failure	Comparable
	50	Incorrect tensioning leading to conductor failure (due to vibration, increased stress)	Comparable
	51	Increased sway leading to increased wear	Needs study
	53	Insulator breaks off due to mechanical overload (for excessive angles). Conductor may break off or float contacting pole.	Comparable
	54	Poorly installed tie wires could break, leading to conductors separating from insulators and contacting pole.	Comparable
	55	Bird caging—conductor strands separate	Comparable

These failure modes that can affect both bare and covered conductors are of particular importance to operators, as risk assessments may need to be updated to reflect the increased likelihood of certain events when switching to CCs. Since no studies were found that directly compared the frequency or severity of these failure modes between covered and bare conductors, the impact on mitigation and maintenance practices has not been quantified.

Despite the dearth of test data on the likelihood and severity of these failure modes for CCs relative to bare conductors, insight can be gained from a first-principles analysis of these failure modes. For example, the vulnerability to fatigue from Aeolian vibration is expected to be different for CCs for several reasons. The Aeolian vortex shedding frequency is inversely proportional to transverse wind speed, and therefore the shedding frequency will be lower for CCs because of the increase in conductor diameter due to the insulation. However, this lower cycle count could be offset by differences in the wind power input of self-damping, which define the vibration amplitude. In addition, Aeolian fatigue failure typically manifests at attachments (clamps), and it is not known whether typical CC connectors are more susceptible to the strain concentrations that lead to failure. Similarly, ice gravity loading and dynamic loads from ice and snow shedding can be expected to differ due to different conductor diameter, surface roughness, weight, and surface temperature. Additional analysis is required to better understand these failure modes.

Failure modes mitigated by covered conductors

The next group of failure modes are those that are largely mitigated by the use of covered conductors. These failure modes are the primary drivers for adoption of CCs, as they represent the risk reduction potential compared to traditional bare conductors. A total of 17 failure modes largely mitigated through the use of CC were identified through the workshop exercise, and are marked with a green checkmark in Table 1. The common theme among these failure modes is that they are created through contact with third-party objects, vegetation, or other conductors that create phase-to-ground or phase-to-phase faults. The available literature, industry testing, and field experiences from utilities around the world suggest that modern CCs can prevent arcing in the medium-voltage range over short time scales, thereby increasing system reliability and public safety, and reducing the potential for wildfire ignition. A full list of failure modes addressed by CCs derived from the failure mode workshop is given in Table 3.

Table 3. Failure modes that affect bare conductors but are largely mitigated by covered conductors.

Hazard	#	Failure Mode
Extreme heat	4	Fault due to sag/clearance issues
Animal	14	Large bird contact of multiple conductors (phase-to-phase contact)
Moisture	15	Atmospheric corrosion of span leading to decreased mechanical strength or increased electrical resistance
	20	Stress corrosion cracking of span
Wind	26	Line slapping (intermittent conductor contact)
	27	Differential wind driven blowout leading to contact of distribution / transmission lines
Tree damage	29	Conductor failure/wire down resulting in loss of service, potential for ignition (along the entire length of bare conductor or exposed section of CC)
	31	Phase-to-phase fault. Potential ignition.
Public/worker impact	39	Potential for shock or electrocution
	40	Potential for guy wire whip to create contact to conductor
	41	Phase-to-phase contact (vehicle)
	42	Phase-to-ground contact (vehicle)
Third-party damage	44	Phase-to-phase contact (tarp)
	45	Phase-to-phase contact (balloon)
	46	Phase-to-phase contact (kite)
	47	Phase-to-phase contact (palm frond)
Maintenance/ Installation	52	Clearance issues due to increased sway

As stated above, these failure modes generally consist of arcing between phases or objects. The primary and secondary effects of these failure modes have implications for system reliability, public safety, and wildfire prevention. For example, arcing between phases due to conductor slapping can create sparks, conductor melting, and/or a possible wire-down scenario. This not only creates an outage risk but also creates potential for a wildfire ignition if dry brush exists below the lines. As will be discussed, available literature indicates that CCs prevent arcing during line slap, such that sparks and melting never occur. In another example, windstorms can blow debris and vegetation into the conductors. While this may not result in a wire-down event, it can create arcing between phases, and the vegetation (e.g., palm fronds) can ignite and fall to the ground. CCs prevent arcing when vegetation is blown into the lines and, therefore, ignition cannot occur.

The extent to which existing information supports the effectiveness of CCs to address these failure modes was considered. For example, it is generally accepted that CCs largely eliminate the risk of vegetation-caused phase-to-phase faults. However, the literature and existing data were analyzed to understand the extent to which this has been proved and whether there are situations that have not been studied. Testing performed by SCE found that CCs prevented phase-to-phase and phase-to-ground faults in field tests that simulated common scenarios such as branch contact, Mylar balloon contact, and conductor slapping (simulating sustained contact) when energized at 12 kV [SCE 2019]. This is relevant and useful testing, though similar laboratory studies to further bolster these conclusions were not found in the available literature.

Most of the available literature consists of high-level observations that correlate system reliability and safety metrics to increases in CC line installation [Leskinen 2004, Li 2010, SCE 2019, Electrical Connection 2021, Ariffin 2012, Rocha 2000, Nishimura 2001]. These studies suggest that the purported benefits of CCs are effective. However, the benefits are not attributed to specific failure modes, but rather overall system reliability and safety metrics. Further, the true technical limits, i.e., to what extent, and over what time scale arcing is mitigated, still lack concrete data. Few publicly available studies were found that directly test the arcing characteristics of CCs. While the SCE testing provides systematic fault testing of CCs, one limitation of the testing performed by SCE is that it was focused on short-term incidental contact and did not test long-term effects such as a tree branch growing into conductor spans. Second, while the success of these tests at 12 kV provides useful data for many distribution-level applications, an effective steady-state breakdown voltage (upper limit) at which arcing eventually occurs was not identified.

Failure modes unique to covered conductors

Failure modes unique to CCs primarily involve damage or degradation to the insulating polymer sheath. These may not be addressed by mitigations that currently exist under asset management plans geared toward bare conductor use. Therefore, Exponent recommends to better understand these failure modes through available literature and targeted testing. When addressing CC-specific failure modes, it is important to consider that some failure modes may simply reduce the benefits of the covering (i.e., return to bare conductor risk level) while others may create a situation that has a unique and independent risk profile relative to a typical bare conductor installation. These factors will be the focus of the Covered Conductor Risks section below. As will be shown later in the report, some of these failure modes have been largely addressed by advances in technology (e.g., UV stabilizers that reduce embrittlement of conductor covering) or are unlikely to occur (e.g., animal chewing the same spot on two adjacent phases). A full list of the CC-specific failure modes derived from the failure mode workshop is given in Table 4.

Table 4. Failure modes that affect *only* covered conductors.

Hazard	#	Failure Mode
Fire	1	Potential damage to sheath, reducing effectiveness
	2	Potential flammability of CC sheath
UV exposure / solar exposure	5	Embrittlement and/or cracking of conductor covering
Contamination	6	Tracking/insulation failure due to moisture/salt (corona)
	7	Tracking/insulation failure due to smoke/ash
Animal	12	Phase-to-phase fault due to animal-damaged sheath (chewing)
	13	Bird dropping degradation of polymer sheath
Ice/snow	17	Freeze/thaw cycles leading to sheath damage
	19	Migration of water within the sheath layer
Wind	28	Damage due to potential for increased loading when new covered conductors replace existing bare conductors on the same poles / crossarms / guys
Tree damage	33	Abrasion of sheath
	34	Cracking of CC sheaths
	35	Heating damage to sheath
	36	Corrosion of conductor due to compromised sheath

Hazard	#	Failure Mode
Maintenance / installation	48	Mechanical damage to sheath (dent/gouge)

Few published studies were found that analyze specific CC-specific failure modes. However, some data have been obtained from CC manufacturers that assists in understanding the limitations of the technology. Hendrix Wire & Cable has performed several tests on the properties and durability of its CC products. These tests include tracking resistance, ultraviolet (UV) resistance, environmental stress cracking, hot creep tests, and performance of CCs in high-contamination environments [Hendrix 2019, Trager 2006]. These test results suggest that modern CC sheathing is resistant to many forms of environmental degradation. However, since these tests were designed to isolate individual variables in a controlled environment, they do not account for all possible variables in a real-world scenario. The failure modes addressed by the Hendrix testing are likely to reduce the effectiveness of covered conductors but, in most circumstances, would not result in a new, higher-risk profile.

Another consideration that is not represented in the failure mode table is the possibility of undetected wire-down events. The CC sheath provides protection from immediate phase-to-ground faults, and therefore may not trigger fault detection systems. This may lead to high-impedance faults and delay necessary field repairs. Downed bare conductors can also result in high-impedance faults, but the situation will be different for CCs since there will be reduced conductor contact with the ground. The potential for these high-impedance fault events that evade detection is the subject of current research, and new early fault detection systems are in development. Operators transitioning to covered conductors may benefit from further research into early fault detection solutions [SCE 2019, Kistler 2019]. These CC-specific failure modes will be the focus of the Covered Conductor Risks section below.

The failure modes discussed thus far are important for understanding the benefits and tradeoffs of implementing CC technology. The next sections will focus on three broad categories of system performance: reliability, public safety, and wildfire ignition. These sections are structured as such because of the available literature, much of which is not specific to individual failure modes but is broader in nature. Available knowledge in these areas from field experience and lab testing will be highlighted, as well as any deficiencies that may warrant further study.

System Reliability

Industry experience has demonstrated an improvement in system reliability when using CCs [EPRI 2014, Leskinen 2004, Li 2010, Nishimura 2001, Rocha 2000, Ariffin 2012]. The primary driver of this improvement in reliability was the decreased probability of fault events, which resulted in fewer system outages. Finland saw a steady decrease in recorded faults in rural areas in the years after 1972, which corresponded to an expansion of CC use. Finland also found that the number of automatic reclosing events decreased to one third as the percentage of CC lines increased from 10% to 50% [Leskinen 2004]. A Taiwanese study similarly found that SAIFI was reduced by approximately 75% and SAIDI was reduced by approximately 86% as the percentage of CCs was increased from 0% to ~55% [Li 2010]. The Electric Power Research Institute (EPRI) also stated that CCs have the potential to reduce tree-caused outages by 40% based on an analysis of data from Duke Energy and Xcel Energy [EPRI 2015].

Public Safety

Public safety is a driver of CC adoption in high population density areas. The Taiwan Power Company observed a ~92% decrease in the number of people experiencing an electric shock from overhead powerlines from 1994 to 2005, when CCs became nearly 60% of their total distribution network [Li 2010]. Operators in Japan observed a similar correlation between accidents and CC installation, noting a factor of 50% reduction in accidents per year from 1965 to 1984 after converting their entire 74 km 6.6 kV network to CCs [Kyushu 1997]. The National Electric Energy Testing, Research and Applications Center (NEETRAC) at Georgia Tech performed a study on the touch current characteristics of CCs vs. bare conductors [NEETRAC 2018]. Both laboratory testing and computer simulations were performed to investigate the results of human bare-hand contact on a two-mile 12 kV distribution system. These tests demonstrated that the contact current for bare conductor was as high as 7 amperes (A), while the maximum contact current for CCs was in the micro-ampere (μA) range. The increased protection against electric shock incidents is significant. However, damage to the conductor sheath or intentional stripping at hardware or dead-end connections will predictably negate or reduce these benefits.

Wildfire Ignition

Utilities in dry climates such as Australia and the western United States are subject to increased risk of wildfire ignition from powerline failures. The reduced propensity for arcing events with CCs is a distinct advantage for minimizing this risk. The Powerline Bushfire Safety Program of the Victoria, Australia, government commissioned a study that examined the fire performance of CCs in “wire down” ignition tests [Marxsen 2015]. Both covered and bare conductors were tested in “wire on ground” faults under severe fire risk conditions. The authors concluded that intact CCs effectively mitigate ignition risk, stating that “the leakage current through the outer plastic covering with the conductor lying on the ground is not sufficient to create thermal runaway so it does not create fire risk.”

However, tests on damaged CCs, i.e., conductors with existing through-thickness coating loss, found that the probability of ignition for CCs can be higher than with bare conductors due to the concentration of arcing at the damage location. On flat ground with uniform dry grass coverage, the estimated probability of fire ignition for a damaged CC was 67% vs. only 37% for bare conductor [Marxsen 2015]. An important limitation of this test is that it assumes direct contact of the fuel source with the bare portion of the damaged conductor. The probability of fire would likely be much lower in areas with non-uniform vegetation cover or uneven ground, reducing the likelihood that coating holidays or stripped connection points would contact dry brush. Further, the study investigated the effects of through-thickness coating holidays but did not address the potential negative effects of partial coating loss from sources such as abrasion.

Summary of Covered Conductor Effectiveness

The prior sections outline field experience and laboratory studies that suggest a significant risk reduction with CC use. Although not all bare conductor failure modes are addressed by specific laboratory studies in controlled environments, sufficient high-level evidence exists to suggest that selected hazards affecting bare conductor are addressed by CC use. As shown in Table 5, there are six hazards that are largely mitigated by CC use, including animal, moisture, wind, tree/vegetation, public/ worker impact, and third-party damage. However, as discussed in the prior sections, this does not suggest that additional work is not required to address these hazards. In many cases, specific test scenarios may still add value to better understand CC use. Such tests scenarios are discussed in the Recommendations section of this report.

Table 5. Hazards that are largely addressed by use of covered conductors are shown in green.

	Hazard	Potential to Mitigate Failures		
		Bare Conductor	Covered Conductor	Sources
Primary Hazards	Tree/vegetation		Reduced risk of tree/veg contact-induced fault	Li 2010; Leskinen 2004; Ariffin 2012
	Wind		Reduced risk of phase-to-phase faulting from slapping or blowout	Leskinen 2004
	Third-party damage		Reduced risk of phase-to-phase faults from contact with kites, balloons, palm fronds, etc.	SCE 2019
	Animal		Reduced risk of animal contact-induced fault	Ariffin 2012
	Public/worker impact		Reduced risk of faults from worker contact or vehicle impact	Li 2010
Secondary Hazards	Moisture		Provides environmental protection except near hardware/dead-ends	
	Ice/snow			
	Fire			
	Extreme heat			
	Maintenance/ installation			
	UV exposure	N/A		
	Contamination	N/A		
	Lightning	N/A		

Comparison to Underground Cabling

The above-referenced literature and case studies demonstrate the advantages of CCs relative to bare conductors. The insulating polymer sheath mitigates several failure modes related to phase-to-phase and phase-to-ground faulting such as conductor slapping, animal contact, tree contact, and downed-conductor scenarios. While these benefits are critical to distribution system reliability and safety, there are additional hazards associated with overhead line constructions that cannot be reduced or eliminated by CCs. For example, CCs are exposed to ice/snow loading, contamination from salt, industrial pollutants, wildfire smoke, and conductor burndown from lightning strikes.

The third option typically considered for distribution system hardening is underground cabling. This method of construction has the potential to mitigate the same failure modes as CCs while also mitigating failure modes related to several other hazards, as shown in Table 6. By routing distribution lines underground, the conductors are protected from weather, fire, and other above-ground hazards that affect both bare and covered overhead conductors.

While there are benefits of underground distribution lines, there are also several economic and logistical challenges associated with their implementation. While economic considerations were largely out of scope for this work, a study conducted by SCE found that the cost per mile for undergrounding an existing overhead line ($3 million per mile) is roughly an order of magnitude more expensive than reconductoring with CCs ($430,000 per mile) [SCE 2019]. Underground conversions also may not be possible in all circumstances due to limitations of the terrain and local geology. For example, underground lines may not be practical or possible in mountainous areas or regions with high earthquake risk. Another consideration is the time required for implementation. Underground conversions are time-intensive projects, so a system hardening program based on undergrounding will take more time to realize any tangible benefits to system reliability/safety. Repairs to underground lines are more expensive and time-consuming due to access difficulties. Finally, there are environmental impacts from underground conversion that do not exist for reconductoring of existing infrastructure. These challenges are not reflected in Table 6 but require consideration in any mitigation implementation strategy.

Table 6. Mitigation potential of distribution line constructions.

	Hazard	Potential to Mitigate Failures		
		Bare Conductor	Covered Conductor	Underground
Primary Hazards	Tree/vegetation			
	Wind			
	Third-party damage			
	Animal			
	Public/worker impact			
Secondary Hazards	Moisture			
	Ice/snow			
	Fire			
	Extreme heat			
	Maintenance/installation			
	UV exposure	N/A		
	Contamination	N/A		
	Lightning	N/A		

Covered Conductor Risks

To understand all potential implications of implementing CCs, failure modes unique to CCs were assessed relative to available literature and testing information. The goal of this comparison was to understand the extent to which the identified CC-specific failure modes represent risks to operators that implement CCs. CC-specific failure modes fall into one of two categories: failure modes that may reduce the effectiveness of the insulating sheath, and failure modes that have a unique and independent risk profile relative to bare conductors (i.e., there is a potential for the risk to be higher than for bare conductors). Table 7 presents the potential consequence of the failure mode relative to bare conductors. The consequences for each failure mode were assigned based on whether the CC failure mode, should it occur, would be likely to decrease, increase, or have comparable risk relative to bare conductors, based on literature review and industry best practices. For example, contamination from salt may result in tracking on the surface of the insulation and may significantly reduce the insulating capacity of the sheath. In this scenario, the CC would have reduced effectiveness relative to a new CC but would still not exhibit a risk profile that is comparable or higher than that of a bare conductor. Complete failure of the CC insulation was considered in this analysis. For simplicity, localized (holiday) or partial failure was not considered. A detailed description of the rationale for each status can be found in the body of this section. Table 7 also lists literature sources and recommendations on whether additional testing is recommended for a given failure mode. As shown in Table 7, several effective mitigations were identified in literature for the CC-specific failure modes. However, there are still failure modes without known or proven mitigations that likely require further testing, research, and/or analysis.

Table 7. Risk of covered conductors relative to bare conductors and knowledge gaps.

Hazard	Scenario	Failure Mode	Consequence of Failure	Mitigation Notes	Selected Literature/ Testing	More Investigation Recommended
Fire	External fire	Potential damage to sheath, reducing effectiveness	Reduced effectiveness of CC	No mitigation effective against extreme temps	No testing or field experience found*	Yes
	Wildfire	Potential flammability of CC sheath	Reduced effectiveness of CC	No mitigation effective against extreme temps	SCE 2019	Yes
UV exposure / solar exposure	Aging / exposure of conductor covering	Embrittlement and/or cracking of conductor covering	Reduced effectiveness of CC	UV inhibitors commonly used to prolong polymer lifetime	Hendrix 2010; Ariffin 2012	No
Contamination	Moisture/ salt	Tracking insulation failure due moisture/salt (corona)	Reduced effectiveness of CC	Tracking and erosion issues are documented for 1-, 2-, and 3-layer CC under polluted conditions	Yousuf 2019: Cardoso 2011; Espino-Cortes 2014	No
	Smoke during fire	Tracking/insulation failure due to smoke/ash	Reduced effectiveness of CC	Tracking and erosion issues are documented for 1-, 2-, and 3-layer systems under polluted conditions	Yousuf 2019: Cardoso 2011; Espino-Cortes 2014	No
Animal	Animal contact	Phase-to-phase fault due to animal-damaged sheath (chewing)	Potentially higher consequence than bare	Redesign of coating to include a two-layer copper screen and use non-HDPE as the sheath material**	Ariffin 2012	No

Hazard	Scenario	Failure Mode	Consequence of Failure	Mitigation Notes	Selected Literature/ Testing	More Investigation Recommended
		Bird dropping degradation of polymer sheath	Reduced effectiveness of CC	Washing conductors may be effective to prevent degradation	No testing or field experience found*	Yes
Moisture	Moisture/salt/ oceanic exposure	Freeze/thaw cycles leading to sheath damage if CC is not co-extruded	Reduced effectiveness of CC	No mitigation identified in literature	No testing or field experience found*	Yes
		Migration of water within the sheath layer	Reduced effectiveness of CC	Proper installation hardware and procedures needed	No testing or field experience found*	Yes
Wind	Pole damage	Increased potential for pole damage (due to heavier conductor and larger wind area)	Potentially higher consequence than bare	Proper standards and procedures needed when retrofitting	Leskinen 2004	Yes
Tree damage	Tree falls, breaks conductor	Live conductor down with no outage	Reduced effectiveness of CC	Literature shows fewer ELIs as CC were introduced into system (see Taiwan section)	Li 2010	Yes
	Tree branch bridges various lines (conductors do not break)	Abrasion of sheath	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes
		Cracking of CC sheaths	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes

Hazard	Scenario	Failure Mode	Consequence of Failure	Mitigation Notes	Selected Literature/ Testing	More Investigation Recommended
		Heating damage to sheath following coating damage	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes
		Corrosion of conductor due to compromised sheath	Reduced effectiveness of CC	Literature shows CC reduced outages due to tree contact	Li 2010; Leskinen 2004; Ariffin 2012	Yes
Maintenance / installation	Sheath damage due to incorrect hardware tool or incorrect stripping	Mechanical damage to sheath (dent/gouge)	Potentially higher consequence than bare	Proper standards and procedures needed	Rocha 2000	No

* Based on a thorough literature review. However, sources may exist that were not found through this effort.

** HDPE may be beneficial for other failure modes.

Risk Discussion

In total, 24 failure modes that are unique to CCs were assessed for their risk relative to bare conductors. The failure modes presented in Table 7 were identified through the joint IOU workshop. However, the frequency of these events (as well as consequence) was not within scope for this effort, and, as such, not all failure modes may present measurable risks to operators. Further, only a portion of these failure modes may result in an elevated risk profile relative to bare conductors, whereas others may only reduce the effectiveness of the covering. The following section discusses special cases from Table 7 in more detail.

Two fire-related failure modes were identified, including damage to, and flammability of, the sheath. In a “worst-case” scenario, if the sheath becomes damaged by fire or heat from a nearby fire, only the metallic conductor will remain. In this case, the effectiveness of CCs is greatly reduced, but no elevated risk relative to bare conductor would result. If, however, the sheath was only damaged in a localized area (versus extensive damage across the entire sheath), then a fault event could have the potential to concentrate heat and arcing in the area of the coating damage in a more severe manner than a bare conductor. In this case, a new, unique risk profile may exist beyond a simple reduction in CC effectiveness. In both cases, no mitigation, testing, or field experience was found in the literature reviewed. For this reason, further research, and possibly testing of these failure modes is recommended to determine the effect of sheath damage due to fire.

UV or solar exposure may accelerate the conductor sheath aging by causing embrittlement and/or cracking. Damage to the sheath may reduce the effectiveness of the CC. UV inhibitors are commonly incorporated in the conductor coating to prolong polymer lifetime [Hendrix 2010, Ariffin 2012].

Contamination from moisture/salt and smoke during fires was considered, as tracking could reduce the effectiveness of the insulation. Tracking of single-, dual-, and triple-layer CCs in heavily polluted areas and coastal areas is well documented in literature [Cardoso 2011, Yousuf

2019, Espino-Cortes 2014]. Similar to the fire hazard discussed above, if the insulation or sheath experiences significant tracking, then the CC effectiveness will be reduced.

Lightning may cause arc damage or melting of the CC that results in a down wire. Reports in the literature indicate CCs help to reduce the number of outages due to lightning, though the mechanism for failure prevention is unclear [Ariffin 2012, Leskinen 2004]. However, the presence of the CC insulation may create an increased risk during a lightning strike. For bare conductors during a lightning event, the electrical arc is more easily dissipated across the metallic surface. In the case of CCs, the insulation may concentrate the electrical arc at a single point during a lightning event, which may cause burndown [Lima 2016, Leal 2021]. Pinholes in the CC insulation may also result in a small reduction of the breakdown voltage. Although lightning arrestors help to mitigate this failure mode, additional testing or research could still be helpful in better understanding the effects of lightning strikes on CCs.

Animal chewing on the conductor coating may cause a localized area of damage such that arcing/heating may be concentrated during a fault. Therefore, this type of damage may present an elevated risk profile relative to bare conductors. Literature sources recommend use of a two-layer copper screen and non-HDPE as the sheath material to deter animals from chewing on the conductors. However, using non-HDPE coatings for the sheath material must be weighed against the benefits of using HDPE materials, especially in areas where animal chewing may not pose a significant risk. No further testing is recommended at this point, as this mitigation is well documented in literature [Ariffin 2012].

Moisture may result in sheath damage due to freeze/thaw cycles or water migration. In the case of water migration, sealing the ends of the conductor may help prevent damage. Few literature sources were found that addressed this specific failure mode or potential mitigation strategies. Additional research, analysis, or testing is recommended to address moisture ingress that could change the breakdown voltage potential of CCs.

Wind damage to poles due to the heavier weight of CCs and larger wind sway is potentially an increased risk compared to bare conductors. This risk can be mitigated by using proper standards and procedures, especially when retrofitting CCs onto existing structures. Additional analysis is recommended to understand potential pole damage due to CC weight.

Tree damage may result in multiple failure modes, as shown in Table 7. On a high level, field experience shows that the number of outages caused by tree contact is reduced when CCs are used [Leskinen 2004, Li 2010, Ariffin 2012, Rocha 2000]. CCs likely decrease the risk of tree-related failure modes. However, the literature studies reviewed do not detail the specific failure modes that are mitigated. Additional research and testing may be needed to determine the extent to which CCs reduce the risk of certain failure modes. Testing focused on long-term tree contact and mechanical testing of the polymer sheath is recommended.

Maintenance and installation considerations are different for CCs compared with bare conductors. Due to the CC sheath, care should be taken while installing CCs to minimize damage from incorrect hardware, stripping, or installation. Additionally, the span sag levels must be adjusted due to increased weight of CCs. Specialized training, standards, and procedures must be followed to account for the additional considerations for CC installation and maintenance. These standards and procedures should help minimize the CC risks and make them comparable to those of bare conductors. However, the additional training, standards, and procedures introduce the potential to increase the risk of CCs compared to bare conductors if not properly followed. No further testing is recommended at this time for this hazard, as long as proper procedures and standards are established for maintenance and installation.

Implementation and Design Considerations

In addition to new failure modes and risks that may be introduced by CCs, there also exist several special considerations for effective design and implementation of CC systems.

Hardware specific to CCs is recommended to ensure consistent and safe installation and reduce the risk of damaging the conductor insulation. This hardware may include insulation-piercing connectors (IPCs), spacers, tangent brackets, and messenger cable. If IPCs are not used, manual stripping of conductor insulation is required at hardware connection points. This creates a risk for local arcing/faults as well as the potential for conductor sheath damage and environmental ingress if not properly executed.

Replacement of bare conductors with equivalent CCs can potentially cause increased sag and can overload the poles, crossarms, or guys because they can increase both gravity and wind loads. The capacity of existing structures needs to be checked before reconductoring is considered. The span length for new lines is typically shorter than bare conductors due to the heavier weight of CCs. However, this can be overcome if a larger messenger wire with greater ultimate tensile strength is used [Cardoso 2011]. Span lengths of 40 meters are common for distribution systems but can be increased up to 400 meters with proper installation [Cardoso 2011].

Installation and maintenance procedures are necessary for CCs due to the special requirements listed above. Proper handling of CCs and considerations when retrofitting CCs onto existing infrastructure is needed. This includes but is not limited to minimizing the amount of coating stripped or removed, covering any exposed conductor, increasing line sag to account for the additional CC weight, and installing proper accessories for lighting arrestors, dead-end covers, composite poles, and crossarms [EPRI 2009 Crudele]. This requires additional personnel training to address unique aspects of CC care, special equipment requirements, and handling during installation and maintenance.

Recommendations

1. Line Tension Study

Several failure modes that affect both bare and covered conductors have the potential to be exacerbated with CCs relative to bare conductors. These are primarily related to the physical differences between the conductors such as diameter, weight, and surface characteristics, leading to potential differences in susceptibility to Aeolian vibrations, galloping, line sway, mechanical overload due to ice accretion, and others (Table 2). Therefore, a thorough understanding of these differences from an analytical perspective is recommended. Specifically, a study investigating the most appropriate line tension considering the size and weight of covered conductor is recommended, which would aid in mitigation of the identified failure modes.

2. Additional Arc Testing

The available literature was found to be promising and suggests that many of the identified failure modes are largely addressed by use of CCs. However, a few key scenarios have yet to be addressed. Further arc testing is recommended to investigate the effects of long-term contact with vegetation, ground, or other objects to better understand delayed high-impedance fault behavior. The effects of wet vs. dry conditions on arcing behavior also warrants further investigation.

3. Covered Conductor–Specific Failure Mode Testing

An understanding of CC-specific failure modes is critical to effective asset management. While implementing CCs will mitigate some risks associated with bare conductor use, there are new failure modes introduced through the use of CCs. The available literature focuses on the benefits of CCs and is relatively lacking with respect to these failure modes. Further research (and potentially testing) is recommended to better understand the following phenomena:

a. Sheath damage and flammability due to nearby fire
b. Tracking due to contamination from salt or smoke
c. Moisture ingress
d. CC sway behavior and the potential for pole damage

4. Early Fault Detection Research

Due to the insulation provided by CCs, a fallen intact conductor may be difficult to quickly detect with existing fault protection systems. Early fault detection schemes are a subject of current research, and additional investigation of this technology is recommended.

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Limitations

At the request of PG&E, SCE, and SDG&E, Exponent has conducted an investigation into the effectiveness of covered conductors for overhead distribution system hardening. Exponent investigated specific issues relevant to this technology, as requested by PG&E, SCE, and SDG&E. The scope of services performed during this investigation may not adequately address the needs of other users of this report, and any reuse of this report or its findings, conclusions, or recommendations presented herein is at the sole risk of the user. The opinions and comments formulated during this assessment are based on observations and information available at the time of the investigation. No guarantee or warranty as to future life or performance of any reviewed condition is expressed or implied.

The findings presented herein are made to a reasonable degree of engineering certainty. We have made every effort to accurately and completely investigate all areas of concern identified during our investigation. Exponent may supplement this report should new data become available.

Attachment E

WMP Risk Spend Efficiency Calculations

Table E.1-1: Liberty WMP Risk Spend Efficiency ("RSE") Calculations[1]

Initiative Name[2]	RSE (Avg./High)[3]	Cost Horizon (2021-2025)	HFTD 2/3?	Comments
Intrusive Asset Inspections/Replace & Repair	0.8/1.8	$23,646,000	Covers all of the service territory	2021 Liberty has undertook an aggressive pole replacement program based on fire condition risk information from intrusive inspections, and the risk mapping completed by Reax.
Undergrounding - Apache	0.76/1.7	$711,367	Both HFTD 2 & 3	Liberty plans to underground segments of its risky Meyers 3100 line located in South Lake Tahoe. Meyers 3100 lies in both HFTD 2 & HFTD 3 areas.
Undergrounding - North Beach Tahoe Vista	0.13/0.3	$11,331,090	HFTD 2	The Brockway 5200 circuit is targeted to be underground by the utility. This circuit has historically been an issue for Liberty, as there have been six-related ignition events on the circuit. An ignition event is not necessarily a reportable incident, but is an incident in which burning, melting, smoking, smoldering, sparking, or arcing has occurred.
Expulsion Fuse Replacement	2.29/5.14	$8,536,953	Will roll out to entire service territory	Liberty is now able to target it's scheduling of its expulsion fuse replacement aligning it with its fire risk profile, addressing the riskiest regions in its service territory first.
Microgrid - Sagehen	0.73/1.64	$671,872	HFTD 2	Liberty has constructed its first microgrid project on the HOB7700 line. The RSE approaches 5 for this location suggesting that it is one of the better options to select for this location.
Microgrid - MEY3300 (Prospective/Study)	0.23/0.52	$2,200,000	Both HFTD 2 & 3	Liberty continues to study strategic locations for grid resiliency and wildfire prevention. The utility's South Lake Tahoe region is the riskiest region, with the heaviest commercial concentration as well. Meyers 3300 & 3400 lines are the highest ranked risk tier at "Very High".
Microgrid - MEY3400 (Prospective/Study)	0.25/0.57	$4,500,000	Both HFTD 2 & 3	Liberty continues to study strategic locations for grid resiliency and wildfire prevention. The utility's South Lake Tahoe region is the riskiest region, with the heaviest commercial concentration as well. Meyers 3300 & 3400 lines are the highest ranked risk tier at "Very High".
Covered Conductor - MEY3300	0.19/0.42	$5,630,192	Both HFTD 2 & 3	Liberty continues to study strategic locations for grid resiliency and wildfire prevention. The utility's South Lake Tahoe region is the riskiest region, with the heaviest commercial concentration as well. Meyers 3300 & 3400 lines are the highest ranked risk tier at "Very High".

[1] Liberty will provide all work papers supporting RSE calculations and explanation of underlying assumptions upon request since the study and results consists of voluminous model outputs and analytical reports.

[2] Liberty concluded that it should not have included an RSE calculation for the DFA pilot program. As part of Liberty's improvements to its RSE calculations, Liberty will remove pilot programs. The main reason for proposing pilot mitigation programs is to test their effectiveness in reducing risk in a particular area. A pilot is initially lower cost than widespread program implementation and provides quantitative data that management can use to assess program efficiency.

[3] Neural Network machine learning RSEs have been calculated for initiatives, however, limited ignition-related risk drivers and CPUC reportable ignitions have produced results less reliable than the RSEs calculated above under a standard approach.

Initiative Name[2]	RSE (Avg./High)[3]	Cost Horizon (2021-2025)	HFTD 2/3?	Comments
Covered Conductor - MEY3400	0.24/0.54	$17,768,226	Both HFTD 2 & 3	Liberty continues to study strategic locations for grid resiliency and wildfire prevention. The utility's South Lake Tahoe region is the riskiest region, with the heaviest commercial concentration as well. Meyers 3300 & 3400 lines are the highest ranked risk tier at "Very High".
Covered Conductor - TAH7300	0.24/0.55	$1,946,643	HFTD 2	The TAH7300 line has historically been a circuit with high performance risk. Surrounded in an area with a lot of vegetation, the line has experienced almost 80 forced outages in six years.
Covered Conductor - TPZ1261	0.4/0.9	$1,461,400	HFTD 2	Liberty's Topaz 1261 line has historically been a line affected by adverse weather, namely strong winds causing service interruptions to customers. While not much vegetation or commercial activity lies in this region, the ability for a fire to spread very quickly is unquestionable.
Enhanced Vegetation Management.	0.27/0.61	$32,255,650	Will cover whole service territory	Targeted and enhanced vegetation management, along with the inclusion of LiDAR now provides Liberty with the ability to make best use of its resources and address the riskiest vegetation in the highest fire risk areas.

Table E.1-2: WMP RSE Additional Calculations

Control/Mitigation	Ignition Events Reduced over Life	NPV Cost of Control/Mitigation over Life	RSE - Avg. Case	RSE - Tail (High Impact Case)
Intrusive Asset Inspections/Replace & Repair	214.6	$42,793,440	0.80	1.80
Undergrounding - Apache	1.3	$279,629	0.76	1.70
Undergrounding - North Beach Tahoe Vista	7.9	$9,603,864	0.13	0.30
Expulsion Fuse Replacement	97.1	$6,780,835	2.29	5.14
Microgrid - Sagehen	3.8	$823,684	0.73	1.64
Microgrid - MEY3300 (Prospective/Study)	4.0	$2,742,086	0.23	0.52
Microgrid - MEY3400 (Prospective/Study)	8.8	$5,577,082	0.25	0.57
Covered Conductor - MEY3300	5.6	$4,737,049	0.19	0.42
Covered Conductor - MEY3400	23.6	$15,601,566	0.24	0.54
Covered Conductor - TAH7300	2.7	$1,790,572	0.24	0.55
Covered Conductor - TPZ1261	3.5	$1,388,105	0.40	0.90
Enhanced Vegetation Management.	43.7	$25,916,294	0.27	0.61

Table E.1-2: Risk Scores Associated with RSE Calculations

Financial Impact - Average Case	Financial Impact - Tail Case	Safety (Serious Inj.) - Average Case	Safety (Serious Inj.) - Tail Case	Safety (Fatalities) - Average Case	Safety (Fatalities) - Tail Case	Reliability - Average Case	Reliability - Tail Case
0.00550	0.0103	0.0878	0.1986	0.0666	0.1501	0.00002	0.00011

Attachment F

Liberty Asset Inspection QA/QC Program

Asset Inspection QA/QC Program

Revision History

Version No.	Revision Date	Revised By	Description of Revisions
1.0	3/1/2022	Blaine Ladd	Initial Release
1.1	3/1/2022	Tony Bustos	Support comments

1. Objective and Overview

The Asset Inspection QA/QC Program is intended to assure that the inspection and corrective action process for existing electric distribution assets is conducted and documented in an accurate and effective manner. The Program is designed to help assure that the electric distribution system is maintained adequately to serve our customers in a safe and reliable manner. The Program is designed to assure compliance with GO 165 for inspection frequency, record-keeping and reporting. The Program also manages and documents the corrective action needs, timelines, and the completion of needed corrective action in accordance with GO 95 and GO 128.

A designated Program Manager will have responsibility for carrying out the program. In addition, a designated Program Administrator will have responsibility for day to day administration of the Program. Appropriate documented quality checks and reviews shall assure the Program is conducted in an accurate and effective manner.

2. Program Responsibilities

Program Administrator – The Program Administrator shall be responsible for providing the administration services in support of inspection scheduling, record keeping and reporting.

Program Manager – The Program Manager shall be accountable for ensuring that the Program is conducted in an accurate and effective manner. Program manager will review and sign off on the Program on a quarterly basis.

Senior Manager – The Senior Manager shall review the Program on an annual basis and ensure the objectives of the Program are being met.

Position	Name	As of Date
Program Administrator	Pam Perkins	1/1/2022
Program Manager	Blaine Ladd	1/1/2022
Senior Manager	Travis Johnson	1/1/2022

3. Program Quality Checks (QA/QC Program)

The Program shall include documented quality checks as follows:

Documented Quality Checks	Description
Third Party Field Inspection Checks	A third party shall randomly reinspect 0.5% of inspections to verify that inspections are being done in a thorough and effective manner.
Program Manager Quarterly Review	Program Manager shall conduct a documented review of the program at the end of each quarter.
Senior Manager Annual Review	The VP of Operations shall conduct a documented review of the program at the end of each year.

Third Party Field Inspection Checks – A minimum of 0.5% of the asset inspects shall be re-inspected by a third party, using Qualified Electrical Workers (QEW's). Re-inspections shall be randomly chosen by numbering the inspections and then generating random numbers to determine which inspections to reinspect. The third party re-inspections will be compared to the original inspections and any issues and their corrective actions will be documented.

Program Manager Quarterly Review - Program Manager shall conduct a documented review of the program at the end of each quarter. Documentation of that review shall be recorded in the Program Manager Review Log. Refer to Appendix A for the Program Manager Quarterly Review Acknowledgement.

The review will include:

- Review of Patrol Inspections completed in the quarter
- Review of Detailed Inspections completed in the quarter
- Verify GEO database is updated with all Detailed Inspections completed in the quarter
- Verify Corrective Actions are completed or on track to complete before timelines expire
- Ensure all as-built information has been updated in GIS

Senior Manager Annual Review – The designated Senior Manager shall conduct a documented review of the program at the end of each year. Documentation of that review shall be recorded in the Program Manager Review Acknowledgement. Refer to Appendix B for the Senior Manager Review Acknowledgement.

The review will include:

- Review quarterly reporting Acknowledgment Reports
- Spot check of reporting done by QAQC team to verify completion

4. Asset Inspections

Inspections shall be conducted as necessary to help ensure reliable, high-quality and safe operation of the electric distribution facilities. Overhead facilities shall meet the requirements of GO 95 and underground facilities shall meet the requirements of GO 128. When issues are found during inspections, the level of severity should be included in the inspection documentation so that the timing for corrective action can be determined. All inspections and corrective actions of violations shall be promptly documented to help assure that the Program is accurate and effective.

The level of severity and timing for corrective actions, for violations found during inspections shall follow the requirements as specified in GO 95. The severity levels and corrective action timing is summarized as follows:

Violation Level	Maximum Timing for Corrective Action
Level 1 – Immediate risk of high potential impact to safety or reliability	Take corrective action immediately
Level 2 – Any other risk of at least moderate potential impact to safety or reliability	6 months for fire risks in tier 3, 12 months for fire risk in Tier 2, 12 months for worker safety, 36 months for other
Level 3 - Any risk of low potential impact to safety or reliability	60 months subject to exceptions for opportunity maintenance (see GO 95 Appendix I for exceptions)

5. Inspection Frequency

Inspections shall be done on a frequency that complies with GO 165. A copy of GO 165 is attached as Appendix D.

Detailed Inspections for overhead distribution facilities are conducted per a 5-year schedule such that the entire overhead system is inspected on a 5-year basis. Patrol Inspections are conducted annually except for circuits undergoing a Detailed Inspection in the same year.

Detailed Inspections for underground distribution facilities are conducted on either a 3-year or 5-year basis depending on type of underground equipment. Submersible transformer locations are inspected on a 3-year basis. All other underground equipment is inspected on a 5-year basis.

Wood poles over 15 years old shall have intrusive inspections done a maximum of every 10 years. Refer to GO 165 for details.

6. Record Keeping

Per GO 165, records for patrol and detailed inspections shall be kept a minimum of 10 years. Intrusive pole inspection records shall be kept for the life of the pole. All inspection records shall include the following minimum information: circuit, area, facility or equipment inspected, inspector, date of inspection, issues/problems found and scheduled date of corrective action. Records shall be kept in a secure manner that facilitates easy review. Electronic records shall be backed up regularly in a secure manner. Records shall be available to provide to Regulators or Management upon request.

7. Inspection Reporting

Reporting to the CPUC shall be done annually as set forth in GO 165. The reporting shall be submitted by July 1st for the previous year. The format shall include the number of inspections that were due and the number of inspections that were due but not accomplished as requested in GO 165.

Included in the annual report will be a documented assessment of the findings listed within a narrative form to accompany reference documents listed herein.

8. Forms (Digital Format)

- Program Manager Quarterly Review Acknowledgement (Appendix A)
- Senior Manager Annual Review Acknowledgement (Appendix B)
- Third Party Inspection Form (Appendix C)
- GO 165 Detailed Inspection Form (Appendix D)
- Line Patrol Inspection Form (Appendix E)

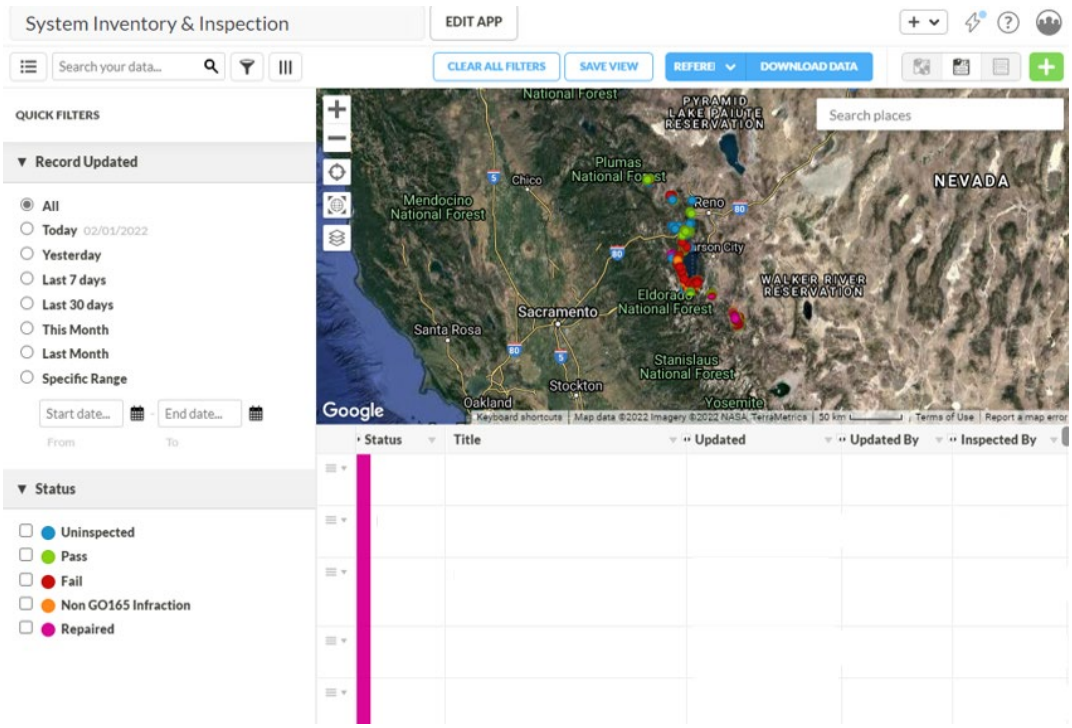
9. Record Keeping Details

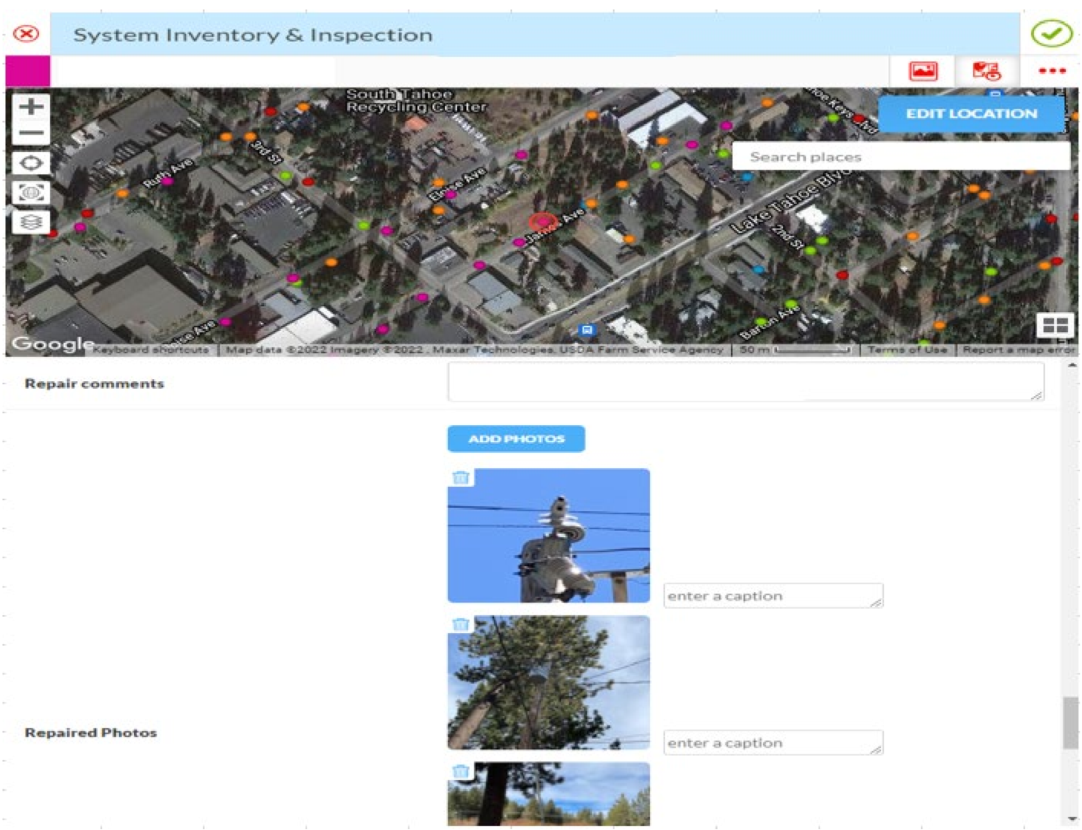
Geo Database is a web and application-based platform that Liberty currently uses to document Detailed Inspections and QC Inspections. This application has been used for Detailed Inspections since 2020. Records shall be stored for 10 years after completion of inspections and will be periodically backed up for security purposes. These records are available upon request by regulators or management.

10. Historic Records

Prior to the year 2020, inspection records were kept on-site in a paper format located in a secure, designated Archives area. These records can still be retrieved upon request from Regulators or Management. Those requests will require additional time to organize and assemble the data. We can assess and assign a timeline as needed.

11. GEO Database Screen Shots (Fulcrum)





Liberty™

ASSET INSPECTION QA/QC QUARTERLY REVIEW SIGN OFF

DATE:

BRANCH OFFICE LOCATION:

OPERATIONS MANAGER :

OBJECTIVE:

Program Manager Quarterly Review - Program Manager shall conduct a documented review of the program at the end of each quarter. The Program is designed to assure compliance with GO 165 for inspection frequency, record-keeping and reporting. The Program also manages and documents the corrective action needs and the completion of needed corrective action in accordance with GO 95 and GO 128.

THE ITEM(S) LISTED BELOW ARE COMPLETED FOR Q1 2022:

☐PATROL INSPECTIONS	☐COMPLETE	☐CORRECTIONS NEEDED	☐ NOT PERFORMED
☐GO 165 INSPECTIONS	☐COMPLETE	☐CORRECTIONS NEEDED	☐ NOT PERFORMED
☐FULCRUM UPDATES	☐COMPLETE	☐CORRECTIONS NEEDED	☐ NOT PERFORMED
☐CORRECTIVE ACTIONS	☐COMPLETE	☐CORRECTIONS NEEDED	☐ NOT PERFORMED
☐ASBUILT INFORMATION UPDATED	☐COMPLETE	☐CORRECTIONS NEEDED	☐ NOT PERFORMED

COMMENTS

PRINT NAME: ________________________________ **SIGNATURE:** ___________________________________

Phone: 800-782-2506
Fax: 530-544-4811
933 Eloise Ave. South Lake Tahoe, CA 96150

Phone: 800-782-2506
Fax: 530-581-0341
701 National Ave. Tahoe Vista, CA 96148

Liberty™

ASSET INSPECTION QA/QC ANNUAL REVIEW SIGN OFF

DATE:

BRANCH OFFICE LOCATION:

SENIOR MANAGER:

OBJECTIVE:

Senior Manager Annual Review - Senior Manager shall conduct a documented review of the program at the end of each year.

THE ITEM(S) LISTED BELOW ARE COMPLETED FOR 2022:

☐PROGRAM MANAGER QUARTERLY REVIEW- Q1 ☐COMPLETE ☐CORRECTIONS NEEDED ☐ NOT PERFORMED
☐PROGRAM MANAGER QUARTERLY REVIEW- Q2 ☐COMPLETE ☐CORRECTIONS NEEDED ☐ NOT PERFORMED
☐PROGRAM MANAGER QUARTERLY REVIEW- Q3 ☐COMPLETE ☐CORRECTIONS NEEDED ☐ NOT PERFORMED
☐PROGRAM MANAGER QUARTERLY REVIEW- Q4 ☐COMPLETE ☐CORRECTIONS NEEDED ☐ NOT PERFORMED

COMMENTS

PRINT NAME: ______________________________ **SIGNATURE:** ________________________________

Phone: 800-782-2506
Fax: 530-544-4811
933 Eloise Ave. South Lake Tahoe, CA 96150

Phone: 800-782-2506
Fax: 530-581-0341
701 National Ave. Tahoe Vista, CA 96148

APPENDIX C - Third Party Inspection Form

Poles that are found to have non-exempt equipment present that would make them subject poles, that do not have a record as being a subject pole will be entered in as 'Pole Brushing Type' subject pole.
PR=Picture Required

QC Assessment Date		Enter date of field assessment.
QC Report Type		Default to Pole Brushing Type
Pole Brushing (Assessment)		
PB	Location Information Inaccurate?	Was the site location or access information not accurate (Pole ID and Address)?
PB	Not a Subject Pole?	Does only exempt equipment exist that would remove the pole from needing to be a subject pole. (PR - show equipment in picture)
PB	Pole Brushing Tag	Was there no pole brushing tag—with contractor information and date—by the pole number or visible from the normal access direction at approximately 5 feet above ground line?
PB	PRC 4292 A: Radial	Did the contractor create a firebreak at ground line, a minimum of a 10-foot radius area, measured horizontally from the outer circumference of the pole, and cleared by removing all flammable materials, including but not limited to, ground litter and debris, duff, and dead or desiccated vegetation that could propagate fire? PR (2 pics min. showing tape- must illustrate finding)
PB	PRC 4292 Radial Non-compliant Pole	Is there enough fuel in the cylinder that could propagate a fire and spread it beyond the cylinder? PR (2 pics min. - must illustrate finding) *This would account for flammable materials entering the cylinder since the date of work and could also include poles that have not been worked to standards or other outside influences (ie customer stacking brush or wood in the cylinder)*.
PB	PRC 4292 B: Vertical 0-8ft	Is from the ground line to 8 feet above the ground line, a minimum of a 10-foot radius area, measured horizontally from the outer circumference of the pole, cleared by removing flammable materials including trees, herbaceous and brush vegetation, grass, trash, debris or other materials?. *Growth from date of work should not count toward finding*. PR (2 pics min. showing tape- must illustrate finding)
PB	PRC 4292 C: Vertical 8ft-highest conductor attachment	Is from 8 feet to the horizontal plane of highest point of conductor attachment free of dead, diseased or dying limbs and foliage; and any dead, diseased or dying trees in their entirety? PR (2 pics min. - must illustrate finding)
PB	ANSI Not Achieved?	Was the pruning not completed per ANSI standard? *Consider available structure and pass all trees considered a utility exception to ANSI. Brushy plants are exempt from ANSI standards.*
PB	Site Not Clean?	Was the debris removal inadequate?*All debris within 100ft of access shall be removed. Anything beyond 100ft may be looped and scattered*. *All areas adjacent to poles that are considered developed shall be left in the same state prior to pole brushing work, except in areas of native vegetation or unimproved areas*. (PR)
PB	Comments / Photos	Enter descriptive comments for all findings and where value is added on non-findings. Add photos (PR) when required and if value is added.

- Comment required for all findings. Comments must be descriptive and not just repeat the assessment.
- PR = Photo(s) required. Where practical capture 1 close up of the issue and 1 farther out to show the area.
- Flag (green/white) only "Reportable" trees or where needed to supplement comment.
- All questions default to 0 (Pass). Maximum quantity incorrect is the quantity listed/worked. Skip over (leave as 0) all questions that do not apply.

QC Assessment Date		Enter date of field assessment.
QC Report Type		Default = Sample. Drop-down choice of Sample and Reportable Types.
PI (Assessment)		
PI	Location Information Inaccurate?	Quantity of trees where site location or access information are not accurate (Pole ID and Address required).
PI	Species Incorrect?	Quantity of trees listed with an incorrect species.
PI	Quantity Incorrect?	Quantity of trees that were listed by the PI, that do not exist.
PI	Trim Type Incorrect?	Quantity of trees listed with an incorrect work category in the Trim Type Field. ("F" category for trees that could strike conductors and FOA/FOB if greater than 12' MCD prescribed) **(Appendix A Trim Type—TT and Removal Prescriptions)**
PI	MCD Not Prescribed?	Quantity of tree where MCD was not prescribed. **(See table 1)**
PI	Valid Description Not Provided when not prescribing MCD?	Quantity of trees where MCD was not prescribed (previous question) and a description of why in the **PI Comments** (e.g., tree structure, past pruning practices, property owner request, etc.) was not provided along with a description of what clearances are to be obtained.
PI	Cleanup Method Incorrect Per Location?	Quantity of trees where the Cleanup Method field would cause the Tree Crew to do the wrong cleanup method based on the location.
PI	Comments / Photos	Enter descriptive comments for all findings and where value is added on non-findings. Add photos (PR) when required and if value is added.
TT (Work Complete)		
WC	Work Not Performed?	Quantity of trees with no visible or likely cuts. (PR)
WC	MCD Not Achieved or Work not completed as prescribed?	Quantity of trees where MCD was not achieved or work was not completed as otherwise described in prescription. Removals not completely removed or visible resprouting from a removal stump.
WC	Will Not Hold?	Quantity of trees where the clearance will not hold for 18months from QC date. Include the clearance, MOG/Estimated growth, and description of where the growth is encroaching from.
WC	Potential Hazard Remaining?	Quantity of tree record units that may pose a hazard after work completion. Tree that is now in decline or dead or presents significant structural issues. (PR)
WC	Site Not Clean?	Quantity of trees where slash and debris removal was inadequate. **No amount of debris, brush, wood is allowed to be left in the cylinder of a subject pole.** (PR)
WC	ANSI Not Achieved?	Quantity of trees where pruning was not completed per ANSI standard. *Consider available structure and pass all trees considered a utility exception to ANSI.*
WC	Other trees affected by Removal?	Quantity of trees worked where tree trimming adversely affected other trees. Caused damage to other trees/roots or opened up to severe new wind exposure.

WC	Site Conditions Not Stable?	Quantity of trees worked causing an unstable site condition. *Consider soil stability, slope and potential erosion.*
WC	Comments / Photos	Enter descriptive comments for all findings and where value is added on non-findings. Add photos (PR) when required and if value is added.

Clearance Distances (Table 1)

Voltage	Maintenance Clearance Distance MCD	Regulation Clearance Distance RCD
Secondary *(includes all stand alone and service drops)*	2’	Covered conductor - Strain or abrasion Open wire- Contact or full cycle of growth between phases.
14.4kV	12’ – 15’	4’
60kV	12’ – 15’	4’
120kV	30’ – 35’	10’

Reportables

QC Report Type	Choose the appropriate Reportable Type from the list below. Note some Reportable types should be chosen whether the tree(s) is in the sample population or not (Any tree) and some reportable types should only be chosen if the tree is not in the sample population (non-listed tree). **DO NOT EDIT existing data if the reportable is an existing sample record.**
Address & pole #	What is the address based on map and what is an adjacent pole #.
Species	Enter species
DBH and Height	Enter DBH and Height
QC Comments	Describe exact location, tree, clearance, growth, and/or condition of tree and/or it’s parts that are likely to fail.

Reportable Tree Procedure (Table 2)

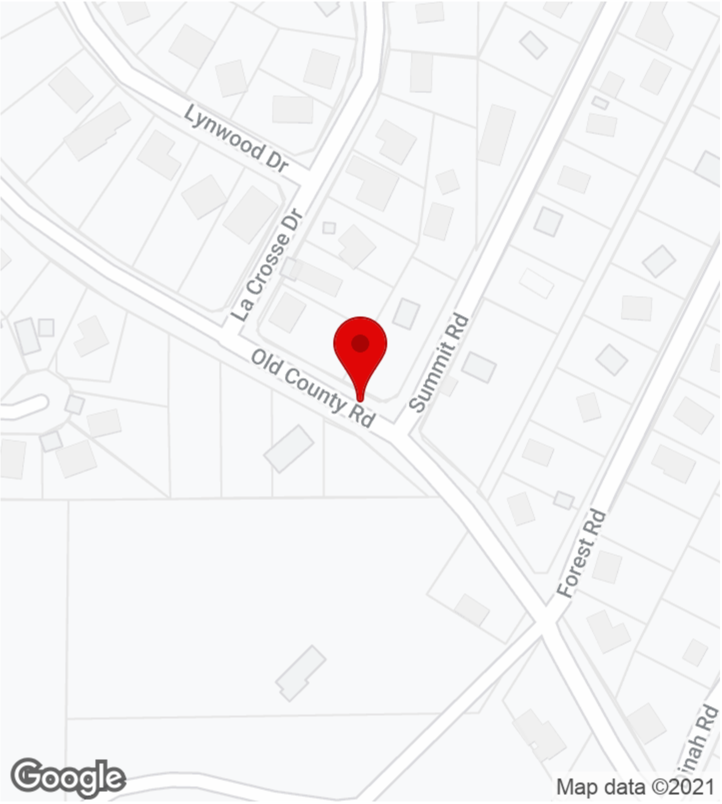
Reportable Type	Conditions	Protocol
Priority 1 Growth Tree	Any tree with evidence of previous or active contact with the high voltage facilities.	Call Senior to discuss and generate a Fulcrum report to be emailed to Senior and System Arborist. **Call System Arborist within 2 hrs of observation.** (PR)
Priority 1 Risk Tree	Any tree, or parts thereof, that is expected to imminently fail and contact the high voltage facilities.	Call Senior to discuss and generate a Fulcrum report to be emailed to Senior and System Arborist. **Call System Arborist within 2 hrs of observation.** (PR)
Priority 2 Growth Tree	Any tree within the RCD (Table 1).	Generate Fulcrum report and email to Senior. (PR)
Priority 2 Risk Tree	Any **non-listed tree**, or parts thereof, that is not a Priority 1 condition and is currently stable but is probable or expected to fail and contact electric	Recorded in the data collection. (PR)

	facilities within 18 months from QC date. .	
Priority 3 Growth Tree	Any **non-listed tree** where the estimated clearance will not hold the RCD for 18 months.	Recorded in the data collection.
Priority 3 Risk Tree	Any **non-listed tree**, or parts thereof, that is not a Priority 1 condition and is currently stable but is probable to fail and contact electric facilities between 18 months and three years from QC date.	Recorded in the data collection. (PR)

Liberty QC

3, Fir - White, 131004.0, R1B, 8.0

11/18/2021, 10:18:12 PM UTC



CREATED

11/1/2021, 1:25:05 PM UTC
by Jared Kim

UPDATED

11/18/2021, 10:18:12 PM UTC
by Jim Gillespie

STATUS

Completed

LOCATION

39.206205, -120.100905

QC Assessment Date	November 18, 2021
QC Report Type	Sample
Circuit	TAHOE CITY 5201
Address	0
City	CARNELIAN BAY
Ownership	Private
Acess	SPAN ALONG OLD COUNTY RD CROSSING SUMMIT RD
Pole ID	131004.0
Span Location	3/4 Span
PI Comments	AVGH&D UL
Alerts	Traffic Control
PI- Location Information Inaccurate?	0
Tree Species	Fir - White
PI- Species Incorrect?	0
Quantity	3
PI- Quantity Incorrect?	0
Height Class	30.0
DBH	8.0
Trunks	1.0
Trim Category	Removing
Trim Type	R1B
PI- Trim Type Incorrect?	0
Cleanup Method	CHIP & HAUL
PI- Cleanup Method Incorrect Per Location?	0
Major Woody Stem	No
Clearance	0.0
PI- MCD Not Prescribed?	0
PI- Valid Description Not Provided for not prescribing MCD?	0
PI- QC Comments	
WC- MCD Not Achieved or Work not completed as prescribed??	1
Inspection Date	September 1, 2020
Tree Number	27077.0
Tree Hazard	WITHIN WIRE CLEARANCE ZONE
Date Complete	August 26, 2021
Status	COMPLETED
WC- Work Not Performed?	1

WC- Will Not Hold?	1
WC- Potential Hazard Remaining?	0
WC- Site Not Clean?	0
WC- ANSI Not Achieved?	0
WC- Other Trees affected by work?	0
WC- Site Condition not Stable?	0
WC- QC Comments	Tree next to pole is 8” dbh, is marked with white x for removal, does not appear worked, still stand and matches count for tree that should have been removed. Tree is offset below lines at 5ft with .75ft growth and wind sway.

Photos



Liberty QC

1, Pine - Jeffrey, 130529, SD, 34

8/23/2021, 3:46:46 AM UTC

CREATED

7/18/2021, 9:19:50 PM UTC
by Jared Kim

UPDATED

8/23/2021, 3:46:46 AM UTC
by Jim Gillespie

STATUS

Completed

LOCATION

39.803271, -120.489449

QC Assessment Date	August 5, 2021
QC Report Type	Sample
Address	0
City	
Ownership	CITY
Acess	SECOND SPAN ON NORTH SIDE OF TRACKS
Pole ID	130529
Span Location	Beginning Span
PI Comments	LOL.
Alerts	
PI- Location Information Inaccurate?	0
Tree Species	Pine - Jeffrey
PI- Species Incorrect?	0
Quantity	1
PI- Quantity Incorrect?	0
Height Class	100
DBH	34
Trunks	1
Trim Category	Pruning
Trim Type	SD
PI- Trim Type Incorrect?	0
Cleanup Method	LOP & SCATTER
PI- Cleanup Method Incorrect Per Location?	0
Major Woody Stem	No
Clearance	12
PI- MCD Not Prescribed?	0
PI- Valid Description Not Provided for not prescribing MCD?	0
PI- QC Comments	
WC- MCD Not Achieved or Work not completed as prescribed??	0
Inspection Date	November 9, 2020
Tree Number	70274
Tree Hazard	WITHIN WIRE CLEARANCE ZONE,FUTURE GROW-INS
Date Complete	April 29, 2021
Status	COMPLETED
WC- Work Not Performed?	0
WC- Will Not Hold?	0

WC- Potential Hazard Remaining?	0
WC- Site Not Clean?	1
WC- ANSI Not Achieved?	0
WC- Other Trees affected by work?	0
WC- Site Condition not Stable?	0
WC- QC Comments	Brush left in continuous pile greater than 18” in depth.

Photos

Liberty - GO 165 Detailed Inspection Form

NOTE: UNDERLINED FIELDS MUST BE ENTERED

District Office: ______ Inspected By: ______ Insp. Date: / /

Substation: ______ Circuit #: ______ Transmission #: ______

City, State: ______ Location Description: ______

Equipment Type (Choose OH or UG - Check One Unit of Plant - Fill In Equipment ID Where Indicated)

☐ OH ☐ UG

Unit of Plant Overhead

- Pole ☐
- Structure ☐
- Tower ☐

Equipment ID ______
(Pole Number)

Unit of Plant Underground

Unit of Plant Underground		Equipment ID
Interrupter	☐	
Junction Enclosure	☐	
Padmount Capacitor Unit	☐	
Padmount Switch	☐	
Padmount Transformer	☐	
Primary Metering	☐	
Subsurface Switch	☐	
Subsurface Transformer	☐	
Vault / Box	☐	

Associated Equipment

	Associated Equipment	Associated Equipment ID	
☐	Capacitor Bank		
☐	Cutout (Fuse)		
☐	Disconnects		
☐	Recloser		
☐	Regulator		
☐	Sectionalizer		
☐	Switch		
☐	Transformer		

Non-GO165 Infractions

Non-GO165 Infractions	
Hot Tap - No Stirrup	☐
Lightning Arrestors	☐
Penta Head Bolts	☐
Pole Leaning / Unsafe to Climb	☐
Pole Needs Replacing	☐
Pole Number Missing	☐
Pole Stub (Old) Needs Removal	☐
Transformer Not Tested	☐
Tree Has Wire Attached	☐

Status (Required)

- ☐ Passed
- ☐ Failed
- ☐ Non-GO165 Infraction

Priority For Repairs on Failed Inspections

- ☐ Within 2 Days
- ☐ Within 12 Months
- ☐ Within 59 Months

Condition Codes For Failed Inspections

Clearance	☐	Foreign Objects on Poles	☐	Missing Bolt Covers	☐
Conductor Issue	☐	Ground Wire / Molding	☐	Oil Leaks	☐
Crossarm Braces Falling Off	☐	Guys / Guards Broken / Loose	☐	Pole Top Split	☐
Crossarm Broken / Split / Loose	☐	High Voltage Sign Problem	☐	Tagging / Labels	☐
Crossarm Needs Replacing	☐	Idle Hardware	☐	Tree / Vegetation Issue	☐
Equipment Anchors	☐	Insulators Need Replacing	☐	Work Space / Climbing Space	☐

Comments (Required For All Failed Inspections / Condition Codes)

REPAIRED

Repair Comments (Required for All Repairs)

Date:

By:

Liberty - GO 165 Detailed Inspection Form

NOTE: UNDERLINED FIELDS MUST BE ENTERED

District Office: ________ Inspected By: ________ Insp. Date: / /

Substation: ________ Circuit #: ________ Transmission #: ________

City, State: ________ Location Description: ________

Equipment Type (Choose OH or UG - Check One Unit of Plant - Fill In Equipment ID Where Indicated)

☐ OH ☐ UG

Unit of Plant Overhead

- Pole ☐
- Structure ☐
- Tower ☐

Equipment ID ________
(Pole Number)

Unit of Plant Underground

Unit of Plant Underground		Equipment ID
Interrupter	☐	
Junction Enclosure	☐	
Padmount Capacitor Unit	☐	
Padmount Switch	☐	
Padmount Transformer	☐	
Primary Metering	☐	
Subsurface Switch	☐	
Subsurface Transformer	☐	
Vault / Box	☐	

	Associated Equipment	Associated Equipment ID	
☐	Capacitor Bank		
☐	Cutout (Fuse)		
☐	Disconnects		
☐	Recloser		
☐	Regulator		
☐	Sectionalizer		
☐	Switch		
☐	Transformer		

Non-GO165 Infractions

- Hot Tap - No Stirrup ☐
- Lightning Arrestors ☐
- Penta Head Bolts ☐
- Pole Leaning / Unsafe to Climb ☐
- Pole Needs Replacing ☐
- Pole Number Missing ☐
- Pole Stub (Old) Needs Removal ☐
- Transformer Not Tested ☐
- Tree Has Wire Attached ☐

Status (Required)

- ☐ Passed
- ☐ Failed
- ☐ Non-GO165 Infraction

Priority For Repairs on Failed Inspections

- ☐ Within 2 Days
- ☐ Within 12 Months
- ☐ Within 59 Months

Condition Codes For Failed Inspections

Clearance	☐	Foreign Objects on Poles	☐	Missing Bolt Covers	☐
Conductor Issue	☐	Ground Wire / Molding	☐	Oil Leaks	☐
Crossarm Braces Falling Off	☐	Guys / Guards Broken / Loose	☐	Pole Top Split	☐
Crossarm Broken / Split / Loose	☐	High Voltage Sign Problem	☐	Tagging / Labels	☐
Crossarm Needs Replacing	☐	Idle Hardware	☐	Tree / Vegetation Issue	☐
Equipment Anchors	☐	Insulators Need Replacing	☐	Work Space / Climbing Space	☐

Comments (Required For All Failed Inspections / Condition Codes)

REPAIRED

Date:

By:

Repair Comments (Required for All Repairs)

LIBERTY - SLT LINE PATROL INSPECTION FORM

NOTE: UNDERLINED FIELDS MUST BE ENTERED

Start Date: / / 2022

District Office: South Lake Tahoe

Patrolled By:

End Date: / / 2022

Substation:

Circuit #:

Transmission #:

City, State: South Lake Tahoe, CA

Location Description:

Equipment Type (Choose OH or UG - Check One Unit of Plant - Fill in Equipment ID Where Indicated)

☐ OH ☐ UG

Unit of Plant Overhead

Pole ☐
Structure ☐
Tower ☐

Equipment ID
(Pole Number)

Unit of Plant Underground

Equipment ID

Junction Enclosure ☐
Primary Metering ☐
Vault / Box ☐

Associated Equipment **Associated Equipment ID**

☐ Capacitor Bank
☐ Cutout (Fuse)
☐ Disconnects
☐ Recloser
☐ Regulator
☐ Sectionalizer
☐ Switch
☐ Other

Status (Required)

☐ Failed

Priority For Repairs on Failed PATROL

☐ Level 1 - Within 2 Days

Condition Codes for Failed PATROL Inspections

Clearances ☐
Crossarm Brace Falling Off ☐
Crossarm Broken / Split / Loose ☐
Crossarm Needs Replacing ☐
Guys / Guards Broken / Loose ☐
Insulators Need Replacing ☐
Pole Top Split ☐
Tree Enchroachment ☐

Comments (Required for all Failed PATROL Inspections / Condition Codes)

REPAIRED

Date:

By:

Repair Comments (Required for all PATROL Repairs)

<table>
<tr><td rowspan="2">Equipment</td><td>Broken / damaged</td><td>Broken / damaged</td></tr>
<tr><td>Equipment leaking oil</td><td>Equipment contacting or in proximity to high voltage conductor</td></tr>
<tr><td rowspan="2">Other / Vegetation</td><td>Vegetation contacting or nearly contacting high voltage conductor</td><td></td></tr>
<tr><td>Vegetation contacting low voltage conductor and compromising structure</td><td>Vegetation contacting cable conductor and compromising structure</td></tr>
</table>

Level 2		
Description: Any other risk of at least moderate potential impact to safety or reliability.		
Repair Interval: Take corrective action within specified time period (either by fully repairing, or by temporarily repairing and reclassifying to Level 3 priority). Time period for corrective action to be determined at the time of identification by a qualified company representative, but not to exceed: (1) six months for potential violations that create a fire risk located in Tier 3 of the High Fire-Threat District, (2) 12 months for potential violations that compromise worker safety, (3) 12 months for potential violations that create a fire risk located in Tier 2 of the High Fire-Threat District, and (4) 36 months for all other Level 2 potential violations.		
Line Element	**Electric**	**Communications**
Conductor	Insulated conductor contacting communication cable / drop	Cable / drop contacting insulated power conductor
	Burned jumper or connector	Cable lashing broken / missing / loose
	Burned high voltage conductor	
	Inadequate clearances	Inadequate clearances
	Unattached	Unattached
Guys	Broken / damaged	Broken / damaged
	Slack / missing	Slack / missing
	Anchor – decayed / loose	Anchor – decayed / loose
Insulator / Cutout	Broken / damaged / missing	
Pole	Broken / damaged	Broken / damaged
	Leaning	Leaning
	Climbing space obstructed	Climbing space obstructed
Crossarm	Broken / damaged	Broken / damaged / deteriorated
	Deteriorated	Broken / damaged guardarm
Equipment	Broken / damaged	Broken / damaged
	Equipment weeping / seeping	Equipment detached / loose
Other / Vegetation	Vegetation causing strain or abrasion on low voltage conductor	Vegetation causing strain or abrasion on cable
Ground Wire / Rod / Moulding	Exposed / broken / missing at public or communication level	Exposed / broken / missing / loose

Level 3		
Description: Any risk of low potential impact to safety or reliability. For Level 3, the condition is not structural, with low likelihood of failure; the condition does not have a significant impact to structural integrity; there is little potential for injury or reliability issues; failure or exposure does not present a significant impact to operations or customers; work procedures mitigate safety concerns.		
Repair Interval: Take corrective action within 60 months, subject to Exception. See Rule 18, Section B(1)(a)(iii).		
Line Element	**Electric**	**Communications**
Conductor		Cable tag missing
		Lashing broken / missing / loose
	Inadequate clearances	Inadequate clearances
	Unattached	Unattached
	Idle	Idle
Guys	Insulator compromised	Broken / damaged
	Slack	Slack
	Anchor – decayed / loose	Anchor – decayed / loose
	Missing marker	Missing marker
Insulator / Cutout	Minor damage	
Pole	Damaged	Damaged
	Leaning	Leaning
	Climbing space obstructed	Climbing space obstructed
Crossarm	Damaged	Damaged (including guard arm)
Hardware	Damaged / loose	Damaged / loose
Ground Wire / Rod / Moulding	Ground wire exposed above public and below communication level	Exposed / broken / missing / loose

Note: Added May 31, 2018, by Decision No.18-05-042.

Below is a non-exhaustive list of typical examples and is not inclusive of all line or equipment types or conditions that could qualify as a Safety Hazard.

Safety Hazard		
Description: A condition that poses a significant threat to human life or property.		
Action: If the facility belongs to the identifying company - take action immediately, either by fully or temporarily repairing the condition. Refer to Rule 18 for notification requirements.		
Line Element	**Electric**	**Communications**
Conductor	Detached / unsupported	Detached / unsupported
	Bare conductors contacting or arcing to other conductors	Cable / drop contacting bare power conductor
	Bare conductors contacting or arcing to communication cables	Cable lashing broken and likely to contact high voltage conductor
	Conductors contacting or nearly contacting the ground or buildings	
Guys	Broken / damaged in proximity to high voltage conductor	
Insulator / Cutout	Broken / damaged / missing	
Pole	Broken / damaged	Broken / damaged
	Excessive lean	Excessive lean
Crossarm	Broken / damaged	Broken / damaged
Equipment	Broken / damaged / detached	Broken / damaged / detached
Other / Vegetation	Vegetation contacting or arcing to high voltage conductor	
	Vegetation contacting low voltage conductor and compromising structure or conductor	Vegetation contacting cable and compromising structure or cable

Note: Added May 31, 2018, by Decision No.18-05-042.

Attachment G

Liberty 2022 Plan to Support Access and Functional Needs Populations During PSPS

Liberty Utilities (CalPeco Electric) LLC (U 933-E)

Liberty's Plan to Support Populations with Access and Functional Needs ("AFN") During PSPS

JANUARY 31, 2022

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SUMMARY

In 2021 and 2022, Liberty participated in collaborative stakeholder efforts to develop a formal communication plan to identify and notify its Access and Functional Needs ("AFN") customers effectively in the event of a Public Safety Power Shutoff ("PSPS"). Liberty engaged with other California electric utilities and participated in the AFN Collaborative Planning Team and AFN Core Planning Team and provided executive representation on the Statewide Joint IOU AFN Advisory Council. Liberty participated in the creation of an annual support plan with assistance from regional and statewide AFN stakeholders with subject matter expertise. Beginning in 2022, this plan will leverage the Federal Emergency Management Administration's ("FEMA") Comprehensive Preparedness Guide Six-Step Process. To measure progress on the implementation of this plan, Liberty will continue to provide quarterly updates to the CPUC.

The focus of Liberty's Plan to Support Populations with Access and Functional Needs During PSPS ("Plan") is to provide outreach to AFN customers who rely on power for devices and equipment for health, safety, and independence and are unprepared for PSPS service interruptions. The IOUs have worked closely with the AFN Collaborative Planning Team to support individuals with AFN during PSPS and to mitigate this risk.

The AFN Statewide Council and AFN Collaborative Planning Team have developed a definition of electricity-dependent individuals who are the main target population Liberty's Plan seeks to support.

Electricity-dependent individuals are those who are at an increased risk of harm to their health and safety during a PSPS, including, but not limited to:

- Medical and non-Medical
- Behavioral, mental, and emotional health
- Mobility and movement
- Communication
- Individuals who require devices for health, safety, and independence

Liberty recently hired a Business and Community Development Manager and Outreach Coordinator to focus on AFN customer needs and planning efforts. The Liberty AFN support team also includes representatives from Wildfire Prevention, Emergency Management, Regulatory Management, and Customer Solutions Management in its collaborative planning process. As a result of inclusion in the AFN Core Planning Team, Liberty has established and initiated connections outside of the AFN Core Planning Team working group with small multi-jurisdictional utilities (SMJUs), as well as agencies such as 211, to explore additional and mutually beneficial approaches to AFN planning in 2022. Liberty has gained helpful insight into the perspectives of participating members of statewide agencies and organizations.

Liberty incorporated universal portions of the Joint IOUs' plan and modified other portions to match the size and scope of its service territory.

INTRODUCTION

Liberty continually monitors weather and other climate conditions to detect fire conditions. When wildfire risk conditions present a safety threat to the safety of its customers and communities, Liberty may initiate a PSPS event as a measure of last resort. While PSPS de-energization activations disrupt the lives of all customers, the following 2022 AFN Plan focuses primarily on individuals and communities with AFN, as PSPS activations may disproportionately impact these individuals. The Plan template was developed collaboratively with the AFN Core Planning Team, which is comprised of leaders in the AFN community and the utilities.

Leveraging the FEMA Comprehensive Preparedness Guide Six-Step Process, Liberty attended AFN Core Planning Team meetings and observed the execution of a "whole community approach" to develop an overarching Joint IOU Statewide template to meet the diverse needs of AFN customers. Liberty utilized this template to develop an AFN plan for 2022, acknowledging the significant variance in its available resources, system limitations, and geographical differences compared to larger IOUs.

Liberty will file its annual plan with the CPUC by January 31 of each year regarding its planned efforts to address people/communities with AFN during PSPS. Additionally, Liberty will provide the CPUC with quarterly updates regarding the progress toward meeting the established plans and the impact of its efforts to address this population during PSPS events.

Subject Matter Experts (Engage the Whole Community)

Each of the IOUs has engaged regional and statewide AFN stakeholders from a broad spectrum of various expertise for the development of this plan in alignment with Step 1 of the FEMA Process:

FEMA Step 1: Engaging the Whole Community in the Planning. Engaging in community-based planning—planning that is for the whole community and involves the whole community—is crucial to the success of any plan.

Statewide Collaborative Planning Team

Participating Utilities	Named parties to include per the Phase 3 OIR PSPS Decision:	Overarching Collaborative Planning Team Representatives with AFN expertise
• San Diego Gas & Electric (SDG&E) • Southern California Edison (SCE) • Pacific Gas & Electric (PG&E) • Liberty • PacifiCorp • Bear Valley	• State Council on Developmental Disabilities (SCDD) • California Health & Human Services (CHHS) • California Foundation for Independent Living Centers (CFILC) • California Office of Emergency Services (CalOES) • Disability Rights California (DRC)	• Alta California Regional Center (ACRC) • American Red Cross (ARC) • California Council of the Blind (CCB) • California Department of Developmental Services (CDDS) • California Department of Social Services (CDSS) • California Public Utilities Commission (CPUC) • Central Valley Regional Center (CVRC)

Participating Utilities	Named parties to include per the Phase 3 OIR PSPS Decision:	Overarching Collaborative Planning Team Representatives with AFN expertise
	• Disability Rights Education & Defense Fund (DREDF)	• Deaf Link, Inc. • Disability Policy Consultant • Interface 211 • Kern Regional Center (KERNRC) • No Barriers Communications (NOBACOMM) • Redwood Coast Regional Center (RCRC)

Liberty will gather ideas from local stakeholders, SMJU AFN contacts, and other AFN experts and will implement feedback where it is deemed beneficial. These groups serve as a sounding board and offer insights, feedback, and input on Liberty's customer strategy, programs, and priorities. Regular meetings are scheduled to identify issues, opportunities, and challenges related to the IOUs' ability to mitigate the impacts of wildfire safety strategies, namely PSPS, and other emergencies throughout California over the long term.

AFN Experts

- Wildfire Community Advisory Councils
  Liberty has established service territory-wide Advisory Boards in each of the four regions served by Liberty to provide hands-on, direct advisory functions regarding de-energization. The four Advisory Boards include the Sierra and Plumas County Board, Nevada and Placer County Board, the El Dorado County Board, and the Mono and Alpine County Board. Each of these Advisory Boards includes public safety partners, communications and water service providers, local and tribal government officials, business groups, non-profits, representatives of people/communities with access and functional needs and vulnerable communities, and academic organizations to advise on best practices for de-energization issues and safety, community preparedness, regional coordination, and the optimal use of existing and emerging technologies. The boards are chartered to meet annually at a minimum and to emulate the approach other IOUs have implemented with their wildfire Advisory Boards.

  Liberty has engaged additional Community Based Organizations since the addition of new roles within the Customer Solutions area of the business and plans to continue growing this essential network throughout 2022.

- SMJU Collaboration
  - In late 2021, Liberty initiated collaboration with PacifiCorp and Bear Valley Electric to establish a working group focused on SMJU AFN planning. This working group provides an opportunity for alignment among the three small electric California IOUs and has proven to be an effective forum to discuss solutions to shared challenges and to share best practices as AFN planning

evolves. Although the larger working groups provide essential information, Liberty will continue and expand focus on SMJU collaboration and discussion throughout 2022 to inform decisions and continually improve consistent and effective AFN customer support.

1. PURPOSE, SCOPE, SITUATION OVERVIEW, AND ASSUMPTIONS

1.1 Purpose/Background

During extreme weather or wildfire conditions, electric utilities may proactively turn off power for public safety as a measure of last resort. While PSPS events disrupt the lives of all customers, the purpose of Liberty's plan is to mitigate the impacts on AFN customers through improved customer outreach, education, assistance programs and services. Liberty's Customer Solutions department hired additional staff in 2021 to increase the resources available to support AFN planning and execution. Liberty looks forward to further development of its AFN plan throughout 2022 and will focus on building foundational connections and expanding existing networks within its communities to continually improve awareness and support of AFN needs. Liberty continues to work to understand existing local resources and establish relationships to support the AFN population throughout the service territory and will make informed improvements through observing practices from the larger IOUs and agencies.

Liberty continues to seek methods of improvement in data collection and analysis despite limitations that exist within its information systems. Liberty completed improvements to its Customer Information System to record additional AFN categories of customers and is continually working to improve its outage management system integration. System improvements have been a significant area of focus throughout Q3 and Q4 of 2021 and are expected to continue through the proposed enterprise-wide Customer First project implementation in 2023.

1.2 Scope

According to Government Code § 8593.3, the 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.

Liberty integrated the following objectives, identified by the AFN council, into its 2022 AFN planning:

- Identify individuals who are electricity-dependent
    - Electricity-dependent individuals are those who are at an increased risk of harm to their health and safety during a PSPS, including, but not limited to, the following:
        - Medical and non-medical
        - Behavioral, mental and emotional health

- Mobility and movement
- Communication
- Individuals who require devices for health, safety, and independence

- Establish a communication plan that reaches all AFN segments
- Continuously improve tools to make them easier to understand and navigate, while making it easier for external organizations to access information
- Identify new programs and resources needed to mitigate the impacts of PSPS
- Enhance existing programs and resources to minimize the impacts of PSPS
- Cultivate new partnerships and expand existing partnerships with the whole community to reach individuals with AFN
- Coordinate and integrate resources with State, community, and utility to minimize duplication
- Establish measurable metrics and consistent service levels
- Serve and adapt effectively to the needs of individuals with AFN before, during, and after PSPS events

1.3 Situation Overview

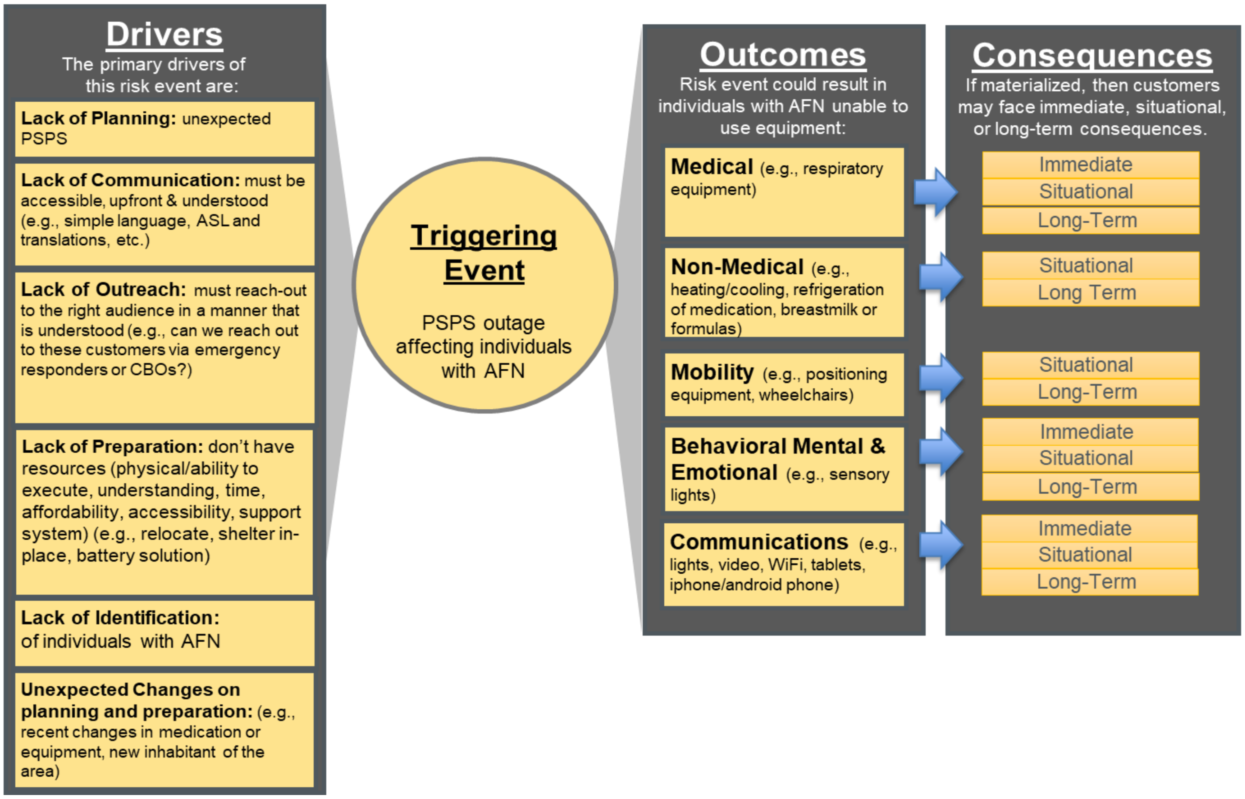
1.3.1 Hazard Analysis Summary – Definition of Risks

FEMA Step 2: Understand the Situation Understanding – the consequences of a potential incident require gathering information about the potential AFN of residents within the community.

The key risk identified by the Core Planning team 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." Disruption in power can have a disproportionate impact on individuals with AFN. Power dependence is dynamic, on a continuum, and may rapidly intensify over time.

- List of Risks and Hazards - Potential Consequences

Liberty understands the risk analysis completed by the AFN Core Planning Team and has found it helpful in identifying the variety of diverse risks that exist for AFN populations.



1.3.2 AFN Population - AFN Identification

Liberty currently serves 43,627 residential customers (18,025 Primary customers) in its territory, including 255 medical baseline ("MBL") customers. Liberty treats MBL customers as critical customers and assumes these customers are dependent on medical equipment to support life functions for PSPS notification purposes. Liberty continues to work on modifications to its systems to allow the recording of AFN customer categories and data beyond MBL customers. As of January 20, 2022, Liberty's Customer Information System ("CIS") categorizes 2,139 elderly customers and 2,621 low-income customers as AFN customers.

As data tracking continues to improve, Liberty will have more visibility into the AFN customer population. In 2021, Liberty established the ability to track AFN categories of customers beyond MBL in its 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. The first phase in integrating this functionality focused on identifying elderly customers and low-income customers. The data flow between Liberty's information systems poses challenges that Liberty is continuing to navigate to support this new functionality in providing accurate data.

As part of Liberty's recent and ongoing system improvements, improved ability to map AFN customers in its Geographic Information System ("GIS") is expected throughout 2022. This initiative has been ongoing since 2021, and its Outage Management System ("OMS") integration follows continued progress in implementing this categorical tracking within the CIS system in 2021.

- Customer Research and Surveys

In 2021, Liberty partnered with MDC Research to execute two waves of 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.

Between August 16, 2021 and September 15, 2021, 204 customers completed surveys. Between November 15, 2021 and December 5, 2021, 218 customers completed surveys.

Notable customer survey findings include:

- Over half (53%) of customers surveyed who rely on electricity for medical needs are aware Liberty provides additional notices prior to a PSPS event.
- 98% of customers surveyed for whom English is not their primary language prefer to receive communications in English. Spanish was a documented preference for only one customer.
- Out of the 47 total MBL customers surveyed, 64% of customers stated awareness of ability to update contact information for PSPS.
- Outreach and engagement satisfaction results demonstrated trending increases in satisfaction overall. Out of the latter 218 customer surveys, 41% reported being satisfied with the amount of information and outreach received about wildfire safety, and 35% of customers reported being satisfied with outreach and engagement efforts about where to find information to help them stay safe and prepare before a wildfire.

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 included two completed CBO interviews, and the second wave included four completed CBO interviews.

Notable CBO interview findings include:

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

Liberty™

Additional survey information used to inform Liberty's 2022 approach in effectively reaching customers includes findings that email remains the most commonly remembered 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 preparedness on TV news, social networks, and through word of mouth.

In 2022, Liberty plans to identify additional resources to collaborate with in executing surveys and research specific to AFN needs before, during, and after PSPS events. Liberty also plans to explore availability of existing resources and identification of gaps that may exist through further discussions and expansion of relationships with agencies, cities, counties, and local organizations.

- Accessibility Webpage and Feedback

Liberty plans to continue to increase the accessibility of its website. Improvements in 2021 include the addition of 211 resource information on the web, as well as development of a self-identification tool for AFN customers in both Spanish and English.

- Success Measures and Metrics

Liberty intends to integrate key performance indicators to measure impacts of PSPS. These indicators include identifying the percentage of AFN individuals who were aware of what support and resources were available to them during PSPS and the percentage of AFN individuals who reported being satisfied with the level of utility communication regarding PSPS preparedness and event updates. Liberty plans to obtain this information by including these indicators in future AFN surveys. Additional methods to gauge effectiveness in AFN support include monitoring web traffic and self-identification tool utilization rates, as well as tracking AFN attendance at community resource center ("CRC") locations during PSPS events.

1.3.3 Capability Assessment - Statewide/Local Research

FEMA Step 3: Operational priorities – specifying what the responding organizations are to accomplish to achieve a desired end-state for the operation.

Liberty has assessed the current state of resources given the matrix provided to the AFN Collaborative Working Team.

Resources		PacifiCorp	Liberty	BVES
Community Resource Centers	Wi-fi, ADA-accessible restroom, bottled water, snacks, charging, chairs, ice, event information & area/weather items	X	X	X
Power Resiliency	Portable backup batteries for Medical Baseline customers	X		X
	Generator Rebate Program	X		
Food Replacement	Food Bank Partnerships			
	Meals on Wheels			
	Community Resource Center – Hot meals			
	Grocery Gift Cards			
	Food delivery			
Transportation				
Lodging			X	X
IOU Customer Communications	Annual Preparedness Outreach	X	X	X
	In Language Materials	X	X	X
	Accessible Materials	X	X	X
	CBO Partners	X	X	X
Training	General Information	X	X	X

Resources		PacifiCorp	Liberty	BVES
	Tabletop exercises and full-scale exercises	X	X	X
Community Engagement	IOU hosted events, Webinars, Advisory Boards, Working Groups	X	X	X
PSPS Notifications	Account Holders	X	X	X
	Non-Account Holders (PG&E/SDG&E Address; SCE Zip Code)	X	X	X
	Broad: via multicultural media, CBOs, and social media	X	X	X
Notification Confirmation (Phone retries & in person doorbell rings)	Life Support/Critical Care	X	X	X
	Medical Baseline	X	X	X
	Self-Certified Vulnerable Customer Status	X		X

FEMA: Step 4: Plan Development Develop and Analyze Courses of Action – This step is a process of generating, comparing, and selecting possible solutions for achieving the goals and objectives identified in Step 3. Planners consider the requirements, goals, and objectives to develop several response alternatives. The art and science of planning helps determine how many solutions or alternatives to consider; what works in one territory might not be available and/or relevant in another territory. While there is a desire to have a consistent response across all the IOUs, it is not entirely possible.

Community Resource Centers**:** Liberty continues to work to establish agreements with community partners and facilities throughout its service territory in preparation for PSPS events. Liberty has CRC use agreements in place in South Lake Tahoe, Loyalton, Truckee, Coleville / Walker, and Washoe Tribal land. Liberty efforts continue to establish additional locations in Portola and North Lake Tahoe. More information on CRCs can be found in section 2.1.2.

Power Resiliency: Section 2.1.3 provides detail on Liberty's current state.

Food Replacement: Liberty has ordered gift cards for use during PSPS events on an as-needed basis for food, lodging, or other customer needs. Liberty plans to offer snacks at CRC locations and continues to expand relationships with local networks to seek existing food replacement services available to customers.

Transportation: Liberty does not currently partner with transportation/paratransit services and plans to seek existing transportation/paratransit services available to customers in 2022.

Lodging: Liberty has accommodated requests for lodging from customers during significant outage events on an as-needed basis in the past and looks to continue partnership with local organizations to remain aware of community needs.

IOU Customer Communications: Annual preparedness outreach: Liberty has an established communications plan for PSPS preparedness outreach. More information can be found in section 2.1.6.

In Language/Accessible Materials: Liberty provides PSPS toolkit information in English, Spanish, French, German, Chinese, Vietnamese, and Tagalog. Liberty looks to continually improve accessibility of materials throughout 2022.

CBO Partners: Liberty communicates with CBOs throughout its service territory and is focused on expanding CBO networks throughout 2022.

Training: Emergency response exercises are executed annually. For more information, please see section 2.1.5.

Community Engagement: Liberty hosts community meetings throughout its service territory to educate customers on the PSPS determination and notification process. When applicable, Liberty will co-host meetings with Public Safety Partners and AFN advocacy groups. Liberty discusses PSPS preparation with CBOs during physical and virtual meetings throughout the year. Liberty also provides PSPS materials to CBOs, cities, counties, and schools.

PSPS Notifications:

> Account holders: Liberty provides PSPS notification to account holders. See section 2.2 for more information.
>
> Non-account holders: Liberty provides PSPS notification to certain non-account holders, such as public safety partners, critical infrastructure contacts and CBOs. See section 2.2 for more information.
>
> Broad: Liberty provides PSPS notification through a variety of communication channels. See section 2.2 for more information.
>
> Notification Confirmation: Liberty confirms PSPS notification receipt of potentially impacted MBL customers. Liberty treats MBL customers as critical customers. See section 2.2 for more information.

1.4 Planning Assumptions

- Liberty provides advanced notice for most PSPS events
- The scope of PSPS events can expand or contract rapidly in a short period based on changing conditions
- Effective support of individuals with AFN requires a whole community (*i.e.*, utilities, CBOs, non-profit organizations, government agencies) approach
- PSPS events may occur concurrently with unrelated emergencies

2. CONCEPT OF OPERATIONS

2.1 Preparedness/Readiness (Before Power Shutoff)

2.1.1 AFN Identification Outreach

Liberty plans to execute AFN identification outreach through a variety of channels throughout 2022, including CBO outreach and targeted customer outreach to encourage AFN self-identification, customer program enrollment, and increased awareness of AFN resource availability. More information on customer preparedness outreach can be found in section 2.1.6.

2.1.2 AFN Support Resources

- 211 Care Coordination & Referral Service

Liberty has engaged 211 contacts throughout the state and plans to continue collaboration throughout 2022. 211 offers support to residents in most counties Liberty serves, excluding residents in Sierra and Plumas county. Liberty implemented a webpage dedicated to 211 customer resource information during 2021. Liberty does not currently participate in 211 Care Coordination contracts. However, 211 partnership is an area of focus and further exploration in 2022.

- Resource Planning and Partnerships

With the recent addition of roles dedicated to AFN support and planning, Liberty anticipates further exploration of CBO and agency partnerships on an ongoing basis throughout 2022 in terms of AFN-specific support and resource planning.

2.1.3 Back-Up Power

- Resiliency Program

In 2022, Liberty expects to file its Customer Resiliency Program ("CRP") application with the Commission. The proposed CRP includes a behind-the-meter ("BTM") battery storage program that will be offered to Liberty's critical needs customers, including MBL, critical facilities, and large commercial ("A3") customers. The BTM program will be structured as a resiliency-as-a-service ("RaaS"), which includes customers paying a monthly fee to participate in the program. For medical baseline customers, Liberty will provide this service at a significantly lower rate ($10/month), and, for medical baseline customers who also qualify for Liberty's low-income California Alternate Rates for Energy ("CARE") rate, the RaaS will be free. The battery systems will be owned and operated by Liberty.

In 2021, Liberty sent a survey to registered MBL customers, which yielded a 30% response rate and an overwhelmingly positive response to the CRP program. The results indicated a small subset of medical baseline customers live in a multi-dwelling home, where an installed battery might not be feasible. Liberty plans to provide resources to these customers to assist with having their own portable system or another alternative solution. Liberty is exploring additional support services to MBL customers during potential PSPS events, including transportation and lodging services. Liberty's difficult terrain and widespread service territory make it challenging to provide transportation and shelter for MBL customers during a PSPS event. However, Liberty will continue to work with its customers on this issue and seeks CPUC and stakeholder input on how to efficiently and cost-effectively develop these additional transportation and shelter services. Liberty has also worked with the other California IOUs to collaborate on best practices related to this issue.

2.1.4 Customer Assistance Programs

- Medical Baseline Allowance Program (MBL)

Liberty's MBL program provides an increase in the baseline allowance to qualified residential customers.

Liberty performs program outreach through bill inserts; radio, social media, and digital advertisements; community events; targeted outreach at mobile home parks and multi-family dwellings; and collaboration with CBOs.

- Energy Saving Assistance (ESA) Program

Liberty offers the ESA program to eligible income-qualified customers to provide energy-efficient home improvements at no cost to the customer.

Liberty performs program outreach through bill inserts; radio, social media, and digital advertisements; community events; targeted outreach at mobile home parks and multi-family dwellings; and collaboration with CBOs.

- California Alternate Rates for Energy (CARE)

Liberty offers a 20 percent discount to qualified low-income primary residential customers who receive their energy directly from Liberty or through a sub-meter, such as in a mobile home park or an apartment complex.

Liberty performs program outreach through bill inserts; radio, social media, and digital advertisements; community events; targeted outreach at mobile home parks and multi-family dwellings; and collaboration with CBOs.

- COVID/Financial Assistance

Liberty has enrolled 2,532 active residential customers in COVID-19 relief payment plans to support in management of arrearages.

The California Arrearages Payment Program will apply approximately $791,000 to approximately 2,400 active residential accounts.

2.1.5 Emergency Operations Centers

Emergency Operations Centers are in both the South Lake Tahoe and North Lake Tahoe offices. Liberty also has the capability of managing events partially or fully via virtual Incident Command with paperless ICS forms, job descriptions, event documentation, and electronic meeting venues. Staff members are trained to perform their roles in both formats.

- Preparation Exercises

In preparation for wildfire season, Liberty will be conducting internal ICS training for its Incident Management Team in May 2022 and a full-scale PSPS exercise in June 2022. The full-scale exercise and the planning meetings leading up to the exercise will include Cal OES, CPUC, CAL FIRE, and OEIS, along with other public safety partners, including government, critical facilities, and the AFN community.

- Training

Liberty employees receive annual Emergency Management Plan training. Instruction includes specific training on the roles and responsibilities of each functional area in support of the ICS at the company level or the Incident Commander at the regional level. Emergency response exercises are executed annually, so employees gain practice in the use of the plan, as well as test the plan for effectiveness. Liberty also participates in regional exercises to train employees and exercise the Emergency Management Plan and will participate in emergency exercises and training with state and regional OES and county emergency offices.

2.1.6 PSPS Preparedness Outreach and Community Engagement

- CBO Outreach

Liberty seeks opportunities to provide PSPS preparedness information through established CBOs throughout the year. For example, Liberty proactively sent PSPS and Wildfire Mitigation preparedness information via email to 34 CBOs, city, county, and school contacts throughout its service territory in 2021 and discusses this information during physical site visits or virtual meetings with CBOs. Liberty also continues to grow and expand CBO networks throughout its service territory, providing materials and resource information for CBOs to share within the communities they serve.

- AFN Customer Outreach

Liberty executes customer outreach to share information about customer programs (CARE, ESA, MBL) and PSPS awareness through a variety of methods, including community events, website resources, social media, bill inserts, targeted outreach to multi-family dwellings and mobile home parks, radio ads (multicultural media), digital ads, print ads, and through call center staff. AFN identification and available resource communication will continue to be a focus in 2022.

As a result of recent MDC Research customer and CBO survey results, areas of focus for 2022 include increased messaging around preparation of emergency kits and readiness. Suggestions provided by customer and CBO feedback highlight the effectiveness of increased use of email and local media and driving website traffic to existing PSPS information. More information on survey results and findings can be found in section 1.3.2.

Development of additional materials related to AFN self-identification and available resources is an area of focus for Liberty in 2022.

Customer recall increased significantly between the recent two waves of MDC surveys in terms of emergency services communications. Liberty plans to consider ways to further partner with local organizations and emergency services to reach customers more effectively.

Utilizing CBO networks and targeted customer program outreach, including multi-family housing, community events, and direct mailings, are an identified area of opportunity to expand customer communications in terms of AFN identification and increased customer awareness of available resources.

- Tribal Engagement

Liberty works to maintain a working relationship with the Washoe tribal community, the only tribal community in Liberty's service territory. Liberty includes the Washoe Tribe as an essential public safety partner and has worked closely with tribal contacts regarding PSPS event preparation and the establishment of a CRC on tribal land during September's potential PSPS event. Liberty acknowledges the unique needs of tribal residents and plans to continue to develop a mutually supportive working relationship with the Washoe Tribe in 2022. The Washoe Tribe has provided helpful insights throughout 2021, not only through regular contact, but also through participation in survey efforts. Partnering with the Washoe Tribe has proven beneficial to the effectiveness of PSPS information sharing throughout the tribal community.

- Marketing and Communications

Liberty has developed the following communications outreach plan to notify AFN customers of pertinent PSPS status updates, including ongoing proactive education.

Liberty will continue to engage AFN customers throughout the year, and especially during wildfire season, to educate them on the PSPS determination and notification process and how customers can prepare for prolonged de-energization through the following channels:

- Community Meetings: Liberty will host community meetings throughout its service territory to educate customers on the PSPS determination and notification process and preparing for PSPS events. When applicable, Liberty will co-host meetings with public safety partners and AFN advocacy groups.

- Toolkits: Liberty will distribute PSPS educational pamphlets, flyers, and checklists in accessible formats. Toolkit information is available in English, Spanish, French, German, Chinese, Vietnamese, and Tagalog.

- Website: Liberty will publish and maintain PSPS web copy outlining Liberty's determination and notification process and detailing ways for customers to prepare for PSPS events, including information specific to AFN populations.

- Social Media: Liberty will post content to Facebook and Twitter notifying customers of Liberty's PSPS determination and notification process.

- Customer Email: Liberty will distribute an email notifying customers of Liberty's PSPS determination and notification process.

- Bill Insert/Mail: Liberty will distribute a bill insert/mailer notifying customers of Liberty's PSPS determination and notification process.

Throughout 2022, Liberty plans to assess and enhance communication accessibility. Notable areas of focus are additional Spanish language support and AFN available resource and self-identification information accessibility on Liberty webpages.

- Translations

Liberty call centers provide customer access to bilingual (Spanish and English) customer service representatives. Call center representatives also have access to additional translation services, supporting customer communication in over 200 languages.

2.1.7 Community Resource Centers (CRCs)

Liberty has established an internal working group comprised of representatives from a variety of departments including Emergency Management and Wildfire Mitigation to focus on CRC planning. The group meets regularly to develop plans, determine priorities, and execute required action for CRC preparedness in 2022. This internal group continues to develop a thorough approach to CRC execution and collaborates externally with community stakeholders.

Liberty plans to provide snacks, water, device charging ability, Wi-Fi, ADA accessible restrooms, resource information, Liberty customer service staff (including bilingual representation when possible), portable cell phone chargers, and blankets at CRC locations. CRC locations present a unique opportunity for program enrollment, PSPS preparedness information sharing, and AFN identification. Liberty plans to provide information on CARE, ESA, and MBL programs at each CRC. PSPS toolkit information will be shared in English and Spanish at CRC locations.

Unique community needs have also been considered in CRC planning, including a water truck for agricultural areas. Ice delivery has also been considered in the planning process, and both services were successfully executed during Liberty's potential PSPS event in September 2021. Liberty will continue to build relationships and solicit feedback and suggestions on community PSPS support from local organizations and customers. Refrigeration needs for medication are also considered in CRC planning as a result of feedback gathered from local CBOs.

Liberty has agreements with five CRC locations throughout its service territory and is actively pursuing additional locations. Collaborative efforts have resulted in a partnership with NV Energy, and Liberty has secured the ability to utilize neighboring CRC locations for customer support when necessary.

2.2 PSPS Activation (During –Emergency Operation Center activated)

- MBL Customer Communication

To identify MBL customers for an event, Liberty identifies MBL customers with accounts in the potentially impacted PSPS zone. The MBL notification sequence is as follows:

1. Everbridge notification (providing text, email, and voice push notifications, with receipt verification capability)
2. If no positive contact, phone call to customer from customer service representative.
3. If no positive contact, physical site visit to the residence.
4. If no positive contact, door hanger notification left at the residence.

To contact MBL customers behind master-metered accounts, Liberty consults a list of master-metered locations to determine if these meters are in the PSPS de-energization zone. Each master meter has a database that provides behind-the-meter information. From this database, Liberty can identify MBL customers and what units they occupy. The communication steps utilized for MBL customer contact also apply to master-metered MBL customer contact.

- PSPS Notifications

Liberty will notify AFN customers before, during, and after a PSPS through the following channels (posted and updated as needed):

Everbridge Alerts: Liberty will distribute an alert through the Everbridge system notifying customers of the status of the PSPS. The Everbridge system consists of a three-part alert: first a text is sent, then an email, and lastly a call.

CBOs: Liberty will notify CBOs that serve AFN populations of the status of the PSPS and request that they distribute the alert to their contact list. CBOs may include:

- Homeless shelters
- Food banks
- Special needs programs

Critical Facilities and Infrastructure: Liberty will notify critical facilities and infrastructure of the status of the PSPS and request that they distribute the alert to their own AFN contact lists. Critical facilities and infrastructure include:

- Police stations
- Fire stations
- Emergency operations centers
- Schools
- Jails and prisons
- Public health departments
- Medical facilities, including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers, and hospice facilities
- Facilities associated with automobile, rail, and aviation transportation for civilian and military purposes

Website: Liberty will publish an alert to the website notifying customers of the status of the PSPS. Microsites are made available in both English and Spanish during a PSPS event.

Social Media: Liberty will post content to Facebook and Twitter notifying customers of the status of the PSPS.

Customer Email: Liberty will distribute an email to AFN customers notifying them of the status of the PSPS. An enhancement in 2021 includes Spanish language messaging within PSPS customer emails.

News Release and Public Service Announcements: Liberty will distribute a news release and/or a public service announcement to local media outlets alerting customers of the status of the PSPS. In 2021, Liberty added multicultural media outlets to lists of media contacts utilized for PSPS notification.

Customer Service Representatives (CSR): Liberty will arm CSRs with information and resources for AFN customers during a PSPS.

Content intended for customers will be translated and disseminated in English and Spanish when possible.

2.3 Recovery (After - Power has been restored)

- Customer Support / Notification

Liberty intends to continue and expand partnerships with local organizations to remain aware of customer needs before, during, and after PSPS events.

Liberty will notify AFN customers after a PSPS through the same channels utilized during a PSPS event described in section 2.2. These channels include Everbridge alerts, communications to CBOs and critical facilities, updates to the Liberty website, posts on social media, customer emails, and news releases. Content intended for customers will be translated and disseminated in English and Spanish when possible.

- After-Action Reviews and Reports

After-action reviews (AARs) with company leadership and the Incident Management Team are conducted subsequent to exercise and/or event. Exercise and event AARs are documented in Homeland Security Exercise and Evaluation Program (HSEEP) format. AARs include an improvement plan that assigns actions and tracks items needing improvement.

- Customer Surveys

An area of opportunity in 2022 for Liberty is expansion of customer, CBO, and public safety partner surveys before and after PSPS events.

Attachment H

Liberty's Comprehensive Emergency Management Plan

Liberty Utilities (CalPeco Electric) LLC

Corporate Emergency Management Plan

1.0 Purpose

The purpose of the Liberty CalPeco Corporate Emergency Management Plan (Plan) is to enhance the Company's capability to respond to and recover from emergencies at all levels, including natural disasters. The plan provides the framework and organizational structure to manage consequences resulting from unexpected loss of infrastructure and equipment through active response and recovery preparedness, resource planning, and practice training exercises. The plan is updated as necessary during the continuous cycle of planning, response, recovery, and mitigation.

2.0 Objectives

The objectives of the plan are to:

1. Protect the life, safety and health of employees and the public;
2. Protect the property and assets of the Company and public;
3. Protect the environment;
4. Provide for the safe and expeditious restoration of service and return to normal operations; and
5. Provide prepared and trained employees with pre-developed plans and information to manage events.

3.0 Emergency Response Organizational Structure and Functions

Emergency preparedness efforts aim at providing organizational structure, resources, and disaster response training necessary for consolidated and effective company-wide response. The utility industry deals with normal to moderate emergencies as part of its normal operations. On the occasions that the size and scope of an emergency reaches beyond the resource and response capabilities of a specific department or area, additional emergency response efforts can be activated under this plan to any level necessary to provide the appropriate resource, information, communication, and coordination.

The model for the company's Emergency Response Organization employs a tiered-level approach to implement an Incident Command System (ICS). Liberty's ICS is based on the National Incident Management System (NIMS), a systematic approach that guides all levels of government, nonprofits and the private sector to work together to manage all incidents. It provides a shared vocabulary, systems and processes to successfully deliver the capabilities described in the National Preparedness System. In addition, it is consistent with California's Standard Emergency Management System (SEMS).

The ICS is an organized approach to effectively control and manage emergency operations should emergency levels reach levels 1-3, as described under section 4.2. The initial tiers, levels 4-5, use the individual department or Regional Command Centers to initially address emergency situations using the ICS. These centers are responsible for command and control of all phases of the emergency in their respective regions and can be supplemented with support from Emergency Management Team members without official activation of the ICS/Incident Command Post. Support may include any or all of the following: Executive Policy Support, Security, Safety, Communications, Operations, Finance, Logistics, Services, and/or Liaisons. Additionally, with or without multiple emergency command centers activated, an ICS may be activated at either the North or South Lake Tahoe locations to assist in resource and information coordination during an emergency or may be activated for large-scale or complex emergencies. The Incident Command Post operates under the ICS for emergency management, and, when the ICS is activated, the Incident Commander oversees the overall management. The ICS function coordinates and directs all response and mitigation efforts inside the perimeter.

1. **<u>Description/Responsibilities of Regions</u>:** The two regions, the North Lake Region and the South Lake Region, operate as independent control areas. The North Lake Region is predominantly sourced from the 120kV system out of Truckee and includes the Palisades Tahoe, Northstar, Portola, and Loyalton areas.

   The South Lake Region is sourced mainly from the 120kV system out of the Carson Valley and includes the Markleeville, Coleville, and Walker areas. Interconnection between the two regions is minimal. Because of this independent configuration, the two regions operate individually during most emergencies. NV Energy supplies all energy to the Company, and all transmission level control is administered through the NV Energy Electric System Control Center. Liberty CalPeco operates within the NV Energy transmission balancing authority and not the CAISO balancing authority.

   Liberty CalPeco is responsible for maintaining communication with NV Energy during an Emergency Event. Information is coordinated with the Transmission Owner (TO), NV Energy, through regular communications with the NV Energy System Control and Dispatch personnel, as well as the Company's System Control (New Hampshire). Absent the ability to communicate via cell or land line, Liberty CalPeco will utilize radio communication to NV Energy's Electricity Subsector Coordinating Council (ESCC) or, if necessary, drive to NV Energy's ESCC locally in Reno, Nevada. When the operation of the transmission service affects customer service, Liberty CalPeco will follow the Liberty CalPeco Outage Communication Strategy described in Section 8.0: Emergency Plan Additional Elements. A transmission system map showing interconnections with NV Energy is attached as Appendix A to this plan.

   Each Regional Manager is responsible for establishing a working relationship with local police, fire, city and county emergency planners and for participating with Local Emergency Planning Committees.

2. **<u>Regional Incident Command Centers (ICC)</u>:** Regional ICCs represent the first level, Levels 4-5, of command and control of an emergency from the individual region. Almost all emergencies are managed at these levels. Field operations and activities are controlled from these ICCs, and field command and control is <u>not</u> transferred to the company ICS if it is activated in support of an emergency event. The South Lake Tahoe and North Lake Tahoe Offices each functions independently for the management of emergencies contained within their areas and is equipped with information and communications equipment for such purpose. Regional centers coordinate resource support between one another when feasible. Essential functions Include:
   a. Primary emergency response with assigned emergency personnel.
   b. Designation of a Regional Incident Commander
   c. Distribution system control, switching and operations directives
   d. Damage assessment, life safety issues assessment, and establishment of response priorities
   e. Management of emergency response resources (materials, equipment, manpower)
   f. Prioritization of restorations
   g. Resource mobilization, allocation and acquisition
   h. Communication and coordination with public safety partners, local governments, media, and customers
   i. Regulatory reporting, as required

3. **Incident Management Team:** The Incident Management Team is activated with the onset of an emergency event (Levels 1-3), in anticipation of an emergency event, or in response to an event with corporate risk, with or without operational damages or deficiencies. This team initially provides support to the regional activities and may consist of the Incident Commander and any or all of the following positions: Incident Commander, Public Information Officer, Safety & Security Officer, Emergency Response Liaison, and Emergency Services Coordinator. This team will, in part, staff the Incident Commander Center if a Level 1-2 emergency event is declared. The additional members of the ICS/Emergency Management Team who also may be activated for any event either to support the regional activities or staff the ICS if activated include: Operations Section Chief, Logistics Section Chief, Planning Section Chief, and Financial/Regulatory Section Chief. An organizational chart showing the makeup of the fully staffed Emergency Management Team and full-function ICS is attached to the Plan and EOC Organization Attachment.

a. Incident Commander: This position is usually the President of the Company; however, this responsibility may be delegated to a manager depending upon the emergency at hand. A single Incident Commander will be appointed for each working shift and will serve as the overall Incident Commander when the ICS is activated. The Incident Commander will be the "individual in charge" establishing a clear chain of command, control of information, and emergency coordination. When the Incident Commander is called upon to assist the Regional Incident Commander, and the ICS has not yet been activated, this individual will serve as a policy resource to the Regional Incident Commander. Roles and responsibilities include:
   i. Providing policy guidance and approval for strategies, actions and activities;
   ii. Communicating directly with Corporate Headquarters; and
   iii. Serving as the responsible authority for strategy and content of Public Information and Company Communications.

b. Public Information Officer (PIO): This position works in conjunction with the Incident Commander or as support to the Regional Incident Commanders to develop communication strategies and content of all information to be disseminated pertaining to emergency event(s). Roles and responsibilities include:
   i. Developing strategy and content of press conferences, news releases, and other media activities;
   ii. Acting as liaison with national and local media and governmental operations centers; and
   iii. Managing employee/Company communications, including status, instructions, and updates as necessary.

c. Safety & Security Officer: This position reviews emergency operation activities to oversee work being performed safely, promote public safety around facilities that may be energized, and assist in prioritization of safety-related matters. This position also provides for the protection and security of company employees and assets, mitigates damage to facilities, and supports effective coordination with law enforcement agencies. Roles and responsibilities include:
   i. Providing security and control of unauthorized, unplanned activities or security violations;
   ii. Providing command and control for evacuation of facilities;
   iii. Providing direct coordination with federal, state or local law enforcement agencies; and
   iv. Providing for employee and public safety.

d. Liaison: The Liaison function is responsible for communications with key local, state, and federal government authorities and officials regarding emergency activities and information. Key functions include:

i. Providing information to officials regarding the status of the company's ability to provide/restore service;

ii. Providing periodic updates based on information gathered at the Regional Control Center and /or Emergency Operations Center; and

iii. Relaying messages regarding governmental representatives' concerns, offers of assistance, etc.

iv. To accomplish these tasks Liaison functions have been divided and assigned to four key staff members. They include a Public Safety Partner/Critical Infrastructure Liaison, a Regulatory Liaison, a Community Based Organizations (CBO) Liaison, and an AFN Liaison. The Public Safety Partner Liaison is responsible for updating our Public Safety Partner and Critical Infrastructure contacts on an ongoing basis, and they work to make sure that all are contacted in an event. The Regulatory Liaison from our Regulatory Department is responsible for coordination and notifications to CPUC and CalOES to include any required OES and California State Warning Center notifications and organizing, the State Executive Briefings during PSPS events. CBO Liaison responsibilities are held by the Community Relations Officer who coordinates with key businesses on a regular basis and organizes CBO briefings during an event. The AFN Liaison position is assigned to the Business and Community Development Officer who works with our AFN and Tribal customers and Community Resource Center (CRC) organization on a regular basis. During an event the AFN Liaison is responsible for AFN coordination and coordination our CRC response if CRCs are activated.

e. Emergency Response Liaison: This position provides a link between the utility and external agencies to provide information regarding any impacts the event may have on the utility's ability to provide/restore service. Roles and responsibilities include:

i. Communicating with local, state, and federal emergency managers and emergency operation centers to keep them appraised of the status of event(s), and assist in the coordination of emergency response efforts as necessary;

ii. Assisting in coordination and communication with other utilities, local or regional government entities, and emergency response agencies as necessary; and

iii. Providing guidance and strategy in company emergency response plans, centers and procedures.

f. Operations Section Chief: This position is responsible for the management of all tactical operations directly applicable to the emergency response, provides direction to the frontline field personnel in damage assessment and priorities, and requests resources necessary to restore service. Areas of responsibility include distribution, transmission, emergency generation, and customer service.

g. Logistics Section Chief: This position is responsible for providing the equipment, supplies, and personnel required to respond to the emergency. This position may engage contract or mutual aid services in support of the emergency and schedules manpower or resources to cover additional emergency operations periods.

h. Planning Section Chief: This position provides analysis of emergency information and situations and develops plans to be used during the response and recovery operations to fully return electric service as quickly as possible for the least cost. This position also facilitates implementation of action plans.

i. Financial/Regulatory Section Chief: This position is responsible for making funds available as needed for the emergency. This position is also responsible for tracking costs and maintaining records throughout the event.
j. Logistics Services Leader: This position provides any support services necessary to manage the emergency situation, including human resources and administrative support.

4. **Incident Command System (ICS) Organization:** The ICS can be activated to provide additional resources support during Level 1-3 emergency events and centralized information coordination and policy direction as necessary to support the activation of a single, or multiple Regional Command Centers. Activation of the ICS is typical when the emergency or combination of events becomes significant in nature, poses significant Company risk, or requires response, support or coordination for or from multiple areas. EOCs can also be activated by the ICS/Emergency Management Team to coordinate emergency information and support utility operations, emergencies, or any other company emergency situations. Either office may be designated as the Incident Command Post during emergencies depending upon accessibility, where the ICS can be most effective and the specific type of emergency. The ICS is activated to provide resource support and information to the regional offices while each regional command center maintains the responsibility for field operations related to assessment, recovery and restoration. The Emergency Management Team/ICS is supported by the EOCs and is activated to the level of support required for the specific emergency. This team may provide the following functions:

a. Policy guidance, strategic planning, and decision-making;
b. Operations/ Resource Support and coordination from activated Regional Command Centers;
c. Logistics and resource procurement, support, scheduling and allocation;
d. Planning, engineering, and technical support as needed for situation assessment and recovery;
e. Finance/procurement of materials, resources and supplies;
f. Media and employee communications/public Information dissemination, both internally and externally;
g. Liaison to governmental EOC and information exchange and coordination with state and local emergency agencies and governments;
h. Safety & Security for employees, work sites, and the general public; and
i. Administrative support and documentation of events, decision-making, resource allocation, etc.
j. Regulatory & Legal assessments in support of strategic decisions.

5. **The Incident Action Planning Process:** The Incident Action Planning Process will proceed as follows:

a. The Plans/Intel Chief provides the Incident Commander with basic information regarding the incident that can include current weather and weather forecasts and resources allocated to the incident. The Plans/Intel Chief's Briefing is documented on the ICS 201 or Situation Summary Form that can form the beginning of the Incident Action Plan.
b. The Safety Officer provides the Incident Commander with an Operations Risk assessment the prioritizes hazards, safety and health issues and appropriate controls. The Safety Officer briefing is recorded on the ICS for 215A.
c. Information provided by the Plans/Intel Chief and Safety Officer is analyzed and assessed during the incident Action Planning Process.
d. The Incident Commander is responsible for establishing the Incident Objectives that are used by the supporting Command and General staff to identify the tactics and resources to achieve the objectives.
e. The resulting Incident Action Plan is briefed during the Operations Briefing and disseminated to the Incident

Management Team via the Incident Action Plan documented on the ICS forms 202 and 204.

f. Actions by the Incident Management Team are documented real time on the Liberty Google Docs Sequence of Events tracker which functions as an ICS form 214.

4.0 Emergency Activation

1. **Activation Levels** - There are five emergency activation levels. See Table 2 for additional details on the operating conditions and typical storm levels related to each activation level.

   a. **Activation Level 5 – Small Impact Event (Localized Response Condition):** The minor disruption of operating systems, business systems, or electric service that can be managed with existing resources at the local or department level. The on-call supervisor or a regional manager typically serves as the Regional Incident Commander throughout the emergency. Other assistance is activated as the Regional Incident Commander deems necessary. The outage is typically restored within one to 12 hours.
   Action: Normal activity, daily internal crew assignments.
   Communication Characteristics:
      - Crisis attracts little or no attention.
      - Public and/or media are typically unaware of the event.
      - Email notification sent to 911@algonquinpower.com.

   b. **Activation Level 4 – Moderate Impact Event (Heightened Alert):** The occurrence of an event that maximizes the resources and management capability of the local region and may require additional resources and support. Often an on-call supervisor or a regional manager serves as the Regional Incident Commander throughout the emergency; other assistance is activated as the Regional Incident Commander deems necessary. The outage is typically restored within 12 to 24 hours.
   Action: Normal activity, daily internal crew assignments. Possible crew transfer between areas. Utility contractor crews (overhead line and tree crews utilized if needed).
   Communication Characteristics:
      - The event is attracting slow but steady media coverage.
      - The public is aware of the event but is attracting very little attention.
      - Email notification sent to 911@algonquinpower.com.

   c. **Activation Level 3 – Serious Impact Event (Enhanced Support):** The occurrence of a disaster or major emergency that may affect several areas of the electric system and may require the services of all operations personnel. The on-call supervisor may serve as the initial Regional Incident Commander but will relinquish that position to the ICS Incident Commander. The outage typically exceeds 24 hours.
   Action: Regional or System ICS may be initiated and Regional EOCs may be opened. All available operations personnel are utilized. Utility contractor, mutual aid assistance, tree crews, and support functions such will be utilized as needed.

Communication Characteristics:

- Event causes growing attention from local and regional media.
- Affected and potentially affected parties notify media.
- Email notification sent to 911@algonquinpower.com, with return 10-minute confirmation.

d. **Activation Level 2 – Major Impact Event (Comprehensive Support):** The occurrence of a disaster or major emergency that affects several areas of the electric system and requires the services of all operations personnel. The on-call supervisor may serve as the initial Regional Incident Leader but will relinquish that position to the regional EOC Incident Commander and then the ICS Incident Commander. Liberty CalPeco may provide resources to other agency EOCs as needed for more efficient and effective communications and coordination during the event. The outage is typically longer than 24 hours.
Action: Regional or System ICS will be initiated. All available operations personnel are utilized. Utility contractor, mutual aid assistance, tree crews, and support functions, such as logistics, will be used as needed.
Communication Characteristics:

- Media are reaching out to employees and non-communication staff for information about the crisis.
- Broadcast and print media are on-site for live coverage.
- In addition to the media, stakeholders and community partners are present at site.
- Email notification sent to 911@algonquinpower.com, with phone call per protocol to confirm receipt.

e. **Activation Level 1 – Catastrophic Impact Event (Emergency Support):** The occurrence of a disaster or major emergency requiring a corporate response. This level requires policy guidance, strategic planning, and coordination of internal and external resources, internal communication, and coordination, dissemination of public information. The field supervisor may serve as the Regional initial Incident Leader but will relinquish that position to the ICS Incident Commander. Liberty CalPeco may provide resources to other agency EOCs as needed for more efficient and effective communications and coordination during the event. Outage will typically affect more than 50% of the customer base and be longer than 72 hours.
Action: Regional and/or System ICS will be initiated. All available operations personnel are utilized. Utility contractor, mutual aid assistance, tree crews, and support functions, such as logistics, will be used as needed.
Communication Characteristics:

- Public health and safety concerns.
- National or international media are covering as major news.
- Major government attention is present.
- There is real or potential environmental harm.
- One or more groups are expressing anger or outrage.
- Email notification sent to 911@algonquinpower.com, with phone call per protocol to confirm receipt.

2. Activation Authorities:

Incident Management Team: The authority to activate the entire Incident Management Team rests with the President or the designated alternate. Authority may be delegated to responsible managers of operations and administrative services to activate an Emergency Management Team as initial response to emergency situations. The President will designate where the Emergency Management Team will be located on initial activation. Administrative support will assist with notification of the Emergency Management Team.

Incident Command Center (ICC): The activation of the full Incident Command Center, the location of the ICC, as well as the levels and functions to be utilized are within the authority of the President or designee. In the absence of the President, the Emergency Management Team will be the decision-making body related to activation of the ICS and the level of activation.

a. Regional Incident Command Center(s): Any team leader, manager, or alternate can activate own organization to the level of support required to respond to any event.

3. **ICC Activation Criteria:** The Incident Command Center is activated when an incident reaches any one of the event characteristic criteria under Activation Level 3: Serious Impact Event (Enhanced Support). However, the Incident Command Center may be activated at any time at the President or the Incident Commander's discretion. When the Incident Command Center is activated, the President and Incident Commander will coordinate with the Emergency Management Team to determine the required resources and support functions to activate.

5.0 Coordination with State and Local Governments

The business manager for each region is responsible for establishing and maintaining a relationship with local governmental agencies and for providing a liaison with the appropriate agency during an emergency event. Emergency Management Team members representing safety and security, emergency response liaison, and public information officer can be utilized to assist in effective coordination and information between state and local government agencies.

Liberty CalPeco is an active participant and supporter of state and local emergency response efforts, including Local Emergency Planning Committees (LEPC), the California Utility Emergency Association (CUEA), the Sierra Front Wildfire Cooperators, and local county offices of emergency services. As part of compliance with G.O. 166, Liberty CalPeco has instituted procedures to conduct biannual emergency preparations meetings with state, county, and local agencies and the TO. As part of such activities, Liberty CalPeco will establish and confirm contacts and communication channels, plans the exchange of emergency planning and response information, and participate in emergency exercises or training. The next meeting is tentatively scheduled for June 7, 2021.

Liberty CalPeco conducted a virtual meeting with representatives of the counties and cities within its service territory on March 3, 2022. Documentation of the meetings is attached as Appendix B to the CEMP.

6.0 Mutual Assistance Agreements

Liberty CalPeco and NV Energy are members of the Western Region Mutual Assistance Agreement (WRMAA). Mutual assistance with NV Energy is provided pursuant to the WRMAA. Liberty CalPeco is also a member of the California Utilities Emergency Association (CUEA), which provides mutual assistance with the other member utilities in California.

Every two years, Liberty CalPeco will invite appropriate representatives of every city and county in its service area to meet with and provide consultation to the Company. Liberty CalPeco will notify the Electric Safety and Reliability Branch of the California Public Utilities Commission 10 days in advance of the meeting. Liberty CalPeco will provide documentation of the meeting to the Commission in its annual G.O. 166 report.

7.0 Supplemental and Contingency Planning Resources

No single plan can foresee all the needs or contain all the information necessary to respond to every event. By design, Emergency Management Plans are concise, uncluttered, and provide sufficient direction to reference information or detail contingency plans that can be obtained in other hazard specific plans or manuals. Many subject areas (*e.g.*, load curtailment, hazardous material response, etc.) contain significant detail and complexity and are too cumbersome to include in an emergency response or business recovery plan. The following is a partial list of contingency plans or manuals that may be included in part or as reference to the Emergency Management Plan.

Supplemental (Contingency) Plans:

a. Fire Prevention Plans
b. Outage Communication Plans
c. Mutual Assistance Agreements
d. Operations Procedure Manuals
e. Spill Response Plans
f. Business Continuity Plans

8.0 Emergency Plan Additional Elements

This Emergency Plan does not attempt to provide solutions for specific emergency scenarios. The Plan provides a general framework for identifying solutions unique to the emergency situation at hand.

1. **Communications:** The Incident Commander serves as the Company spokesperson unless that function is specifically delegated by the Incident Commander. Delegation is typically to an individual trained in the function of the Public Information Officer (PIO). Other Company personnel shall refrain from disseminating information to the media.

   The PIO is responsible for distributing relevant information in a timely manner to the general public via the news media. The PIO serves as the primary point of contact at the Company for news media inquiries. This position also facilitates communications between news reporters and other company representatives. The PIO or alternate should be available throughout the event to provide periodic updates to the news media. If practical, the PIO should be on site at the Incident Command Center. The PIO is responsible for maintaining up-to-date telephone and fax listings for news media outlets.

   a. Prior to an Emergency: The PIO will annually update all media contact information. Information will be disseminated to the public through the media, advising customers what to do to prepare for extended outages and what emergency supplies may be necessary to keep on hand. Customers will be given information on safety around downed power lines and other precautions to observe during an event. Media outlets will be provided with emergency contact information for the Company, including names and contact information for each regional office, as well as the PIO. The PIO will oversee the updating of operations contact lists with both primary and secondary contact information available. The PIO will create standard messaging for common events. Pre-developed information is attached as Appendix C to this plan.

b. <u>During an Emergency</u>: The Incident Commander or designee contacts the PIO and provides outage information for distribution to the media. The PIO provides the media with outage information, including the following:
   i. When did the outage begin?
   ii. What caused the outage?
   iii. How many customers are affected?
   iv. Where is the outage located?
   v. What are we doing about the outage?
   vi. When is service expected to be restored?
   vii. A telephone number customer can call for information.
   viii. A description of safety hazards such as downed power lines.

c. <u>Notifications</u>: A contact list of local governmental agencies, municipalities, and media outlets within Liberty CalPeco's service territory has been developed. During a major outage or emergency that affects a significant number of customers, an email is sent to personnel, agencies, and media to provide information, detail, and status of the outage. As the outage or emergency continues, status update emails and/or phone calls will be made to keep the agencies and media informed. Once the outage has concluded and the system is back to normal, a final email will be sent to close out the communication of the incident.

d. <u>Customer Information/Contact</u>: The primary point of customer contact is telephone information via live customer contact or the Interactive Voice Response (IVR) and messaging system.
   i. High Call Volumes: Customer Service Representatives (CSR) will answer as many incoming calls as possible in the individual offices. During periods of high call volume, the customer service centers will utilize an IVR system that will allow callers to receive customized messages about outages that are being addressed in Liberty CalPeco's service territory. The IVR system will also allow for emergency calls to be routed to a live CSR for life support or life-threatening emergencies and allow customers to receive a call back regarding their outage if they choose that option.
   ii. CSRs will be able to develop custom IVR messages that will be heard by the customers on the IVR system for any calls that are not answered by a live CSR. Standard emergency message consists of day, month, time, general areas affected, cause (if known), and estimated restoration time (if known). A follow-up message with more specific information can be recorded as more information is received. The IVR system is capable of automated callbacks if the customer selects this option from the outage script.
   iii. The Customer Services Manager or the designated alternate may approve a request for mutual assistance as a Requesting Utility. The Company has mutual assistance agreements established with NV Energy and other utilities in case call volume or phone access prevents the Company from directly handling calls.
   iv. Following the emergency event, the PIO or designee will provide media outlets with a wrap-up of information regarding the resolution of the emergency and any final information for the public. Customers who requested a return call following the event will be messaged by phone. These steps finalize the emergency communications with the public.

e. <u>Communications Strategy – Planned Outages</u>
   i. In the event of a planned power outage, such as a public safety power shutoff (PSPS), Liberty

CalPeco will communicate directly and indirectly with its customers and the public utilizing various media and communication platforms.

ii. Medical Baseline or Green Cross customers who will be affected by the outage will receive a direct phone call from Liberty CalPeco staff notifying them of outage details, including but not limited to time, duration, and reason. Liberty CalPeco's goal, whenever possible, is to notify the medical baseline customer group 72 hours in advance of a planned outage. All other affected customers will receive direct text, email, and/or voice message notification via the Everbridge system, informing customers about the outage and outage details, including but not limited to time, duration, and reason. Liberty CalPeco's goal, whenever possible, is to notify the general public and non-medically sensitive customer group 48 hours in advance of a planned outage.

iii. Liberty CalPeco's social media accounts and website will also be updated with outage information. Local website, radio, newspapers, and TV media will be notified with a request that they broadcast the public service announcement (PSA).

iv. Necessary updates to all customer categories will be directly communicated 24 hours in advance and right before the outage commences, as appropriate.

v. During the outage, updates will be sent directly to customers, the media, and posted to social media accounts and the Liberty CalPeco website as updates are available or situations change.

vi. Once the outage has concluded, a final update will be sent directly to customers and media, as well as posted to social media accounts and the Liberty CalPeco website with a request that any customers still without power notify the Company.

f. <u>Communications Strategy – Unplanned Outages</u>

i. Once an incident has been identified and affected customers isolated, affected customers will receive direct text, email, and/or voice message notification via the Everbridge system. Medical Baseline or Green Cross customers affected will receive a direct phone call from a Liberty CalPeco employee in addition to the automated notification. Liberty CalPeco will also post outage information on social media accounts and its website. All appropriate media outlets will be notified if the severity of the outage warrants.

ii. Customers will receive direct text, email, and/or voice message updates via the Everbridge system and again when the outage has concluded. Once power has been restored, Liberty CalPeco will request any customer still without power to contact the Company.

g. <u>Communication Channels</u>

i. Indirect Communication:
   - Liberty CalPeco website: Libertyutilities.com

ii. Liberty CalPeco Social Media:
   - Twitter @LibertyUtil_CA
   - Facebook @LibertyUtilitiesLT

iii. Media, including but not limited to:
   - SouthTahoeNow.com
   - Tahoetopica.com
   - Sierra Sun
   - Tahoe Daily Tribune
   - KTKE radio

- KRLT Radio
- NPR
- Reno and Sacramento local TV stations

For the period July 1, 2020 to June 30, 2021, Liberty CalPeco reported zero Major Outages, defined as when at least 50 percent (*i.e.*, 24,000) of Liberty CalPeco's serviceable customers experience a simultaneous, non-momentary interruption of service.

2. **Governmental and Regulatory Communications:** During emergency events, Liberty CalPeco is closely involved with local law enforcement, medical agencies, and fire agencies. In larger emergencies, city and county emergency management representatives provide coordinating responsibilities in responding to the event. In escalating emergency events, additional coordinating resources, such as an Emergency Response Liaison and/or a Government Liaison, can be activated by the Incident Commander.
    a. During emergency events, Liberty CalPeco will provide communications to, or a liaison to, the highest level of city or county Emergency Operations Center activated. This will be accomplished through the Emergency Response Liaison or Government Liaison, who are both members of the Emergency Management Team.
    b. If an emergency event is large enough to initiate the activation of a State level Emergency Operations Center or Regional Emergency Operations Center, the Emergency Response Liaison will communicate with the State Emergency Operations Center (EOC). The California state coordination will be through the California Utilities Emergency Association (CUEA) Emergency Operations Center. The CUEA operates as a Utility Branch of the State Standardized Emergency Management System (SEMS) and reports directly to the State Operations Center (SOC) in Sacramento. As a member of CUEA, Liberty Utilities is party to its Mutual Assistance Agreement and is represented in the Utility Operations Center (UOC), which is located in the State Operations Center (SOC). All mutual assistance activities will be communicated to the State EOC and the Utilities Operations Center (UOC)/Office of Emergency Services (OES) during an emergency at 916-636-3704 or by email at CUEAUOC@CALOES.CA.GOV.
    c. Non-emergency 24/7 contacts for Cal OES are Don Boland (don.boland@caloes.ca.gov, O: 916-845-8517, C: 916-717-7570) and Jenny Regino (jenny.regino@caloes.ca.gov, O: 916-845-8518, C: 916-709-6708). Website: WWW.CUEAINC.com
    d. Liberty CalPeco is a member of CUEA, which provides emergency planning, training, resource assistance, and operates the Utility Emergency Operations Center as the Utility Branch for the Office of Emergency Services (OES) at the State EOC. The Company Emergency Response Liaison is a responder to the CUEA EOC, which is co-located with the SOC.
    e. The CPUC requires reporting for safety and for substantial outages. Guidelines for reporting to the CPUC follow this section in Table 1. Reporting forms and checklists are also contained in the Regulatory Reporting Attachment to this plan.
    f. Communications Strategy – Planned Outages
        i. In the event of a pre-planned power outage, such as a PSPS, Liberty CalPeco will communicate with government/agency partners and the public/customers. Liberty CalPeco will inform the Electric Safety and Reliability Branch of the CPUC by email at ESRBcompliancefilings@cpuc.ca.gov at least 10 days in advance of any pre-event coordination.

ii. City/county, OES offices, critical infrastructure, CPUC, and agency partners will receive the earliest notifications of a "significant" planned or potentially planned outage, up to eight days in advance, when possible. Liberty CalPeco will continue to provide updates to these contacts as the outage event nears or whenever conditions or details change. Communications will be executed by text, email, and phone calls.

iii. City/county, OES offices, critical infrastructure, CPUC, and agency partners will also receive updates at the 48-hour mark. Local website, radio, newspapers, and TV media will be notified and requested to broadcast the PSA.

iv. Updates will be directly communicated 24 hours in advance and right before the outage commences, as appropriate.

v. During the outage, updates will be sent directly to city/county, OES offices, critical infrastructure, CPUC, agency partners, and media, as well as posted to social media accounts and the Liberty CalPeco website as updates are available or situations change.

vi. Once the outage has concluded, a final update will be sent directly to city/county, OES offices, critical infrastructure, CPUC, agency partners, and media, as well as posted to social media accounts and the Liberty CalPeco website with a request that any remaining power outages or issues be communicated with Liberty CalPeco.

g. <u>Communications Strategy – Unplanned Outages</u>

i. Liberty CalPeco will post outage information on social media accounts and website. Media, city/county, OES offices, critical infrastructure, CPUC, and agency partners will be notified if the severity of the outage warrants.

ii. City/county, OES offices, critical infrastructure, CPUC, and agency partners will receive direct text, email, and/or voice message updates via the Everbridge system and again when the outage has concluded. Once power has been restored, Liberty CalPeco will request that any remaining power outages or issues be communicated with Liberty CalPeco Communication Channels

h. <u>Communication Channels</u>

i. Direct Communication:
- Customer contact database
- City/county, OES offices, critical infrastructure, CPUC, and agency partner database

ii. Indirect Communication:
- Liberty CalPeco website: Libertyutilities.com

iii. Liberty CalPeco Social Media:
- Twitter @LibertyUtil_CA
- Facebook @LibertyUtilitiesLT

iv. Media, including but not limited to:
- SouthTahoeNow.com
- Tahoetopica.com
- Sierra Sun
- Tahoe Daily Tribune
- KTKE radio
- KRLT Radio
- NPR
- Reno and Sacramento local TV stations

3. **Public Safety Partner Emergency Coordination:** Liberty CalPeco serves customers in seven California counties. Larger, more populous counties may have a more robust emergency management department and more emergency providers, whereas smaller ones are more limited. Regardless of county size and structure, the following agencies, departments, and/or facilities are part of Liberty CalPeco's Public Safety Partner group with whom Liberty CalPeco coordinates in advance of and during any emergency or significant power outage.
    a. Public Safety Partners
        i. Cal OES
        ii. County OES Offices
        iii. Fire departments (including volunteer)
        iv. Sheriff offices
        v. Highway patrol
        vi. Local police departments
        vii. Town managers/mayors
        viii. Utility providers (water, wastewater)
        ix. Telecom companies
        x. Cellular tower engineers
        xi. Hospitals and medical clinics
        xii. School districts
        xiii. County health and human services
        xiv. County superior court
        xv. Community emergency response teams (CERT)
        xvi. County supervisors and/or staff
        xvii. Social services
        xviii. Airports

Liberty CalPeco maintains a robust Public Safety Partner database of key contacts. This database is reviewed with each partner agency/department/facility on an annual basis for accuracy. Liberty CalPeco participates in several emergency operation and communication workshops and hosts its own such workshops throughout the year to familiarize all partners of standard emergency operating procedures and communication efforts. Emergency plans and operations are tested with partners during TableTop exercises and practiced on a smaller scale during small, less significant power outage scenarios. Documentation for the TableTop exercises, held November 13, 2018, and the Business Community Meeting, held November 15, 2018, is attached as Appendix D to this plan.

Liberty CalPeco has extablished the following PG&E points of contact for coordination with Pacific Gas & Electric Company, Public Affairs.
For incidents related to the Meyers 3300 line: Sarah Rasheed, email: SFRA@pge.com, cell: (209) 660-3069
For incidents related to Nevada and Placer Counties: Brandon Sanders, email: BLSY@pge.com, cell: (916) 531-0230

4. **Communications with the Transmission Owner (NV Energy):** NV Energy is the TO for Liberty CalPeco. During emergencies, the Emergency Management Team (EMT) Emergency Response Liaison is responsible for coordinating and communicating all anticipated major system impacts to the Company's System Control Center in New Hampshire. The System Control Center is responsible for providing information to the NV Energy Distribution Desk or Transmission Desk, as appropriate. The 24/7 contacts for the Company's System Control Center are Control Operation's Desk 603-216-3669 and Dispatch 603-216-3612. The 24/7 contacts for NV Energy are Transmission Desk 775-834-3541, Distribution Desk 775-834-7541, and Electric Outage Coordinator 775-834-4546.

A. Emergency Communications Plan with TO (NV Energy):
   I. The Emergency Response Liaison is responsible for the collection of information from field operations personnel and the Emergency Management Team at the EOC.
   II. The Emergency Response Liaison is responsible for providing information to the Company's System Control Center (New Hampshire).
   III. After a determination is made by the System Control Center or the Emergency Management Team, the Company's System Control Center will contact NV Energy's System Control Center. Depending on the nature of the emergency, the Transmission Desk or the Distribution Desk of NV Energy will be contacted by the Company's System Control Center.
   IV. Relevant information requiring dissemination to the Emergency Management Team or field operations personnel from NV Energy will be communicated by the System Control Center to the Emergency Management Team. The Emergency Management Team is responsible for providing this information to field operations personnel.

B. Tasks Requiring Communication with the TO (NV Energy):
   I. Providing system status information, including status of the primary control center, key facility outages (generation and transmission), demand and energy requirements, and level of assistance available to help mitigate the emergency.
   II. Coordination of emergency generation dispatch to help maintain line and substation loadings to within limits.
   III. Coordination of tie line restoration and necessary phase angle adjustment (if possible).
   IV. Notification and timing of switching and restoration efforts and necessary load curtailments.
   V. Sharing information regarding crews and personnel available to provide emergency assistance. This can be activated using the Western Region Mutual Assistance Agreement (WRMAA), of which both NV Energy and Liberty CalPeco are members.
   VI. Providing regular and timely updates regarding the status of the emergency and the outlook for resolution.
   VII. Providing notification when the emergency has passed, and the system is operating normally.
   VIII. Coordination of restoration steps between systems.
   IX. Coordination of energy emergency conditions (*i.e.*, emergency generation status and/or non-availability).
   X. Coordination of emergency voltage violations and/or reactive assistance.
   XI. Coordination and notification of a Public Safety Power Shutoff (lines, service area, agencies, customers impacted).

C. Other tasks may require notification and coordination with NV Energy depending on circumstances. If there is any question regarding whether a task may affect NV Energy's system, the task must be coordinated as discussed above.

   If a NV Energy related transmission outage affects Liberty CalPeco, the communications strategy outlined in Liberty CalPeco's CEMP, Section 8.0.1.f. will be followed for communications with customers and media. The strategy outlined 8.0.2.g. will be followed for communications with governmental and regulatory agencies

   There are additional tasks that NV Energy must communicate and coordinate with Liberty CalPeco during emergencies. These tasks may include but are not limited to:

   I. Operation of phase shifters (Cal phase shifter).

II. Re-dispatch of generation (Kings Beach diesels used for the benefit of NV Energy).
III. Reactive adjustments (South Lake Tahoe transmission loop).
IV. Activation of NV Energy's Public Safety Outage Management (PSOM) affecting any Liberty CalPeco customers.

TABLE I: Reporting Guidelines for Public Utility Commission

The following is a summary of reporting requirements. The Corporate Regulatory Manager should be consulted for any discrepancies or questions regarding reporting of incidents or events. The table is a guideline only.

What	Definition	Report To	When	How
Major Outage	Customers simultaneous and non-momentary outage of 50% of customers	**1)** OES Warning Center **2)** CPUC Energy Division	**1)** OES within one hour **2)** CPUC within one hour **3)** CPUC every four hours with updates	**1)** OES 800 number **2)** Energy Branch Phone, Mail **3)** Phone mail or email as per Energy Division request. **4)** Safety Branch **a)** Report at http://www.cpuc.ca.gov/emrep/ **b)** Report at 800-235-1076 **c)** Follow up with email or fax within 24 hours **d)** Formal Report 20 days
Sustained Outage	**A.** Outage lasting over 24 hours or expected to total over 60,000 customer hours (or an event likely to lead to such a situation) **B.** Outages expected to accrue over 300,000 customer hours.	CPUC Energy Division	1) By 9:00 AM the next Business Day 2) CPUC Energy Branch within one hour	**1)** Energy Branch Phone, Mail **2)** Safety Branch **a)** Report at http://www.cpuc.ca.gov/emrep/ **b)** Report at 800-235-1076 **c)** Follow up with email or fax within 24 hours **d)** Formal Report 20 days
Notable or Newsworthy	Event involving facilities or personnel reported in two media markets or in national media.	**1)** CPUC Energy Division **2)** CPUC Utility Safety Branch	**1)** CPUC Energy Branch within one hour **2)** Safety Branch within two hours during working hours and four hours outside of working hours	1) Energy Branch Phone, Mail 2) Safety Branch **a)** Report at http://www.cpuc.ca.gov/emrep/ **b)** Report at 800-235-1076 **c)** Follow up with email or fax within 24-hours **d)** Formal Report 20 days

TABLE I: Reporting Guidelines for Public Utility Commission (Cont.)

What	Definition	Report To	When	How
Load Shed / Rolling Blackout	Loss of power supply leading to extensive load shedding or rolling blackout. Imminent or planned load curtailment or rotating outages of firm load.	CPUC Energy Division	CPUC within one hour and every time a new circuit is interrupted.	1) Energy Branch Phone, Mail 2) Safety Branch **a)** Report at http://www.cpuc.ca.gov/emrep/ **b)** Report at 800-235-1076 **c)** Follow up with email or fax within 24 hours **d)** Formal Report 20 days
Injury / Fatality	Fatality or personal injury rising to the level of in-patient hospitalization.	**1)** CPUC Utility Safety Branch **2)** CPUC Energy Branch	**1)** Safety Branch within two hours during working hours and four hours outside of working hours. **2)** Energy Branch within one hour	1) Energy Branch Phone, Mail 2) Safety Branch **a)** Report at http://www.cpuc.ca.gov/emrep/ **b)** Report at 800-235-1076 **c)** Follow up with email or fax within 24 hours **d)** Formal Report 20 days
Damage to Property	Damage to property of the utility or others estimated to exceed $50,000 and are attributable or allegedly attributable to utility-owned facilities.	CPUC Utility Safety Branch	Safety Branch within two hours during working hours and four hours outside of working hours	1) Energy Branch Phone, Mail 2) Safety Branch **a)** Report at http://www.cpuc.ca.gov/emrep/ **b)** Report at 800-235-1076 **c)** Follow up with email or fax within 24 hours **d)** Formal Report 20 days

EHS will participate in all reporting and investigation of injury, fatality or damage incidents according to 8800-100-200-001- Incident Reporting and Investigation Procedure.

5. **Safety** - This Plan requires a “Safety First” response to all emergencies—the safety of employees, contractors, assisting crews, and the general public is to be promoted at all times.

a. Public Safety: Liberty CalPeco provides ongoing public electric safety courses and information so that the public will be prepared when an emergency event occurs. These programs are provided year-round to all levels of schools, businesses, service clubs, trade shows, and expositions. Additionally, Liberty CalPeco routinely provides electric safety training to local and regional law enforcement, fire, county and state transportation, and other emergency response agencies. Public safety training is the responsibility of all.
    i. During an emergency event, Liberty CalPeco may utilize standby personnel, trained in general electrical safety, to observe and report electric hazard conditions and assist in perimeter safety around identified hazards due to unsafe conditions until qualified electric personnel arrive. The public shall heed all warnings and barriers placed by Liberty CalPeco to secure hazards.

b. Employee Safety: Employee safety is identified as a key element in this Emergency Response Plan. Electric trade personnel, including groundpersons, helpers, apprentices, journeymen, lineman, troublemen, and inspectors, are provided the highest level of safety and skills training to perform in both daily and emergency situations.
    i. Only qualified and trained personnel may perform safety sensitive functions including switching, de-energizing, overhead and underground operations, repairing, and assessing damage.
    ii. To promote employee and public safety, the design, installation and operation of equipment and automatic protection schemes for transmission and substation equipment must remain in place, protection schemes may not be bypassed by any employee.
    iii. Liberty CalPeco employees will follow procedures in accordance with OSHA 1910.269 regulations.
    iv. Non-trade personnel who are utilized in assistance with emergency repair (metering, meter reading, construction, etc.) must be trained in general electric safety before assisting in emergency field response.

c. During an Emergency Event: Liberty CalPeco will respond to immediate life safety issues as the top priority. Once a hazardous situation is reported, immediate response will be provided by line crews, troublemen, inspectors, or other trained personnel to assess and make the situation safe by de-energizing, supporting, removing, repairing, or barricading and providing for safety stand-by personnel, as necessary.
    i. All field response employees shall have safety training aligned with their respective roles.
    ii. All electrical switching and reporting shall be handled through the appropriate controlling parties to ensure both employee and public safety.
    iii. Liberty CalPeco will provide regular public information, typically in the form of media messages or alerts, regarding unsafe or hazardous areas or conditions that the public should be kept informed about.
    iv. In the event of an area emergency that is life or property threatening, the Emergency Alert System (EAS) will be enabled through the local or county Emergency Management or Public Safety office. The Company will advise the Emergency Management agencies when such an alert is necessary.

v. Public Safety Agencies will be utilized, as necessary, for traffic control and perimeter safety until qualified personnel arrive to clear a hazard situation. Agencies will be used if necessary to control public disturbances and establish safety controls for the public.

vi. Employees are monitored for appropriate meal breaks, hours worked and safety compliance; when emergencies are expected to last more than 24 hours, shifts will be established to cover work and employees will be given appropriate rest periods.

vii. Weather and road conditions are monitored for worsening conditions, so workers do not become stranded at remote work locations.

viii. Work may be curtailed, even if customers remain out of service, until safe work conditions prevail.

6. **Damage Assessment:** The designated Incident Commander is responsible for determining how damage assessment will be best achieved for the specific emergency situation and other functions to be performed by specific individuals. The Incident Commander may delegate the responsibility, or a piece of the responsibility, to the manager(s) or other qualified individual(s) or retain this responsibility.

   a. The designated Damage Assessment Leader(s) will then become responsible for assembling, assigning and setting priorities for Damage Assessment Teams in accordance with Restoration Priority Guidelines or priorities established by the Incident Commander. The Damage Assessment Leader assigns priority on damage with life-threatening conditions, impact on life-support customers, critical facilities, and impact on emergency services. Liberty CalPeco dispatches appropriate and additional resources to address the damage based upon damage assessment priorities.

   b. Company crews, linemen, troublemen, electric inspectors, utility designers and/or engineers will be first called for damage assessment. Company personnel will be augmented as necessary and approved by the Incident Commander with contractors and/or mutual aid parties.

   c. Company teams will be given priority patrol assignments along with difficult hazards and locations unfamiliar to visiting teams.

   d. Documentation of Damage: All damage will be recorded by the teams on the circuit maps IN RED. The standard symbols shown below shall be used.

      i. Standard Symbols : F= Blown line Fuse
      B = Tree Branch on Line
      P = Primary Span Down - Provide # _____
      S = Secondary Span Down - Provide # _____ PB = Poles Broken - Provide # ______________________
      PL = Poles Leaning - Provide #_____(Correction Required) SV= Service(s) Down - Provide # ____
      ____
      TR = Transformer(s) Down - Provide # _____
      OIL = Oil spill, Clean up needed; Identify PCB or Non-PCB

   e. Damage Assessment Teams shall take the following standard supplies to the field to perform assessments: clipboard, circuit map books, red pens, pencils or pens, patrol report forms, area or street Maps, store request forms, PCB oil test kit, digital camera (with charged battery), warning tape, cones, and barriers.

f. All maps and related information shall be returned to the Damage Assessment Leader as soon as practicable for restoration decision making.

g. To the extent practicable, downed or damaged facilities shall be isolated, secured and warnings applied utilizing cones, warning tape, or other barriers or warnings.

7. **Restoration:** Service restoration is unique to each emergency and prioritizing restorations may depend upon a number of factors including safety, accessibility, availability of repair parts, availability of personnel, as well as other factors. This element of the plan identifies general prioritization guidelines for restorations, but allows for the Incident Commander or designee to alter priorities according to the circumstances of the emergency and in coordination with essential load customers and government agencies involved.

   a. General restoration will proceed in this order:
      i. Radial transmission and substations.
      ii. Distribution circuits with essential customers, such as health care facilities, utilities, public safety, governmental facilities, and lifeline customers.
      iii. Circuits with the greatest number of customers.
      iv. Primary taps followed by secondary lines.
      v. Individual services that are accessible and serviceable can be addressed.
      vi. Below is the priority list of essential customers. Specific contact information and locations of each essential customer may be found in the customer information attachment to this Plan. Priority assumes circuits, equipment, and services are accessible and repairable.

1. Health Care Facilities
   a) Primary care hospitals
2. Utility Services/Districts
   a) Public utility districts
   b) Telecommunications
   c) Water and water treatment
   d) Pipeline
3. Public safety agencies
   a) Public safety dispatch centers
   b) Law enforcement facilities/holding facilities
   c) Fire operations facilities
   d) Transportation equipment and facilities
4. Government facilities
5. Green Cross and Life Line

6. **Mutual Aid:** The Incident Commander has responsibility for mobilizing resources, contracting for additional assistance and supplies, and calling for assistance from neighboring utilities through Mutual Aid Agreements.

   a. The type, size, and duration of an emergency event will determine, in varying degrees, the amount of resources required to respond to the event. The Regional Operations do not have enough resources to respond to a large emergency event without supplementing manpower, equipment or materials from other sources.

b. The Incident Commander will direct the requests for additional internal (Company) and external resources. The Incident Commander must approve the use of Mutual Aid.

c. Requests may be made for efficiency and not for exhausted resources. Resource requests may include trade and non-trade personnel to assist in safety standby, damage assessment, planning or liaison activities, or materials and equipment necessary to facilitate restoration of utilities.

9.0 Training

Liberty CalPeco employees receive Emergency Management Plan training annually. Instruction includes specific training on the roles and responsibilities of each functional area in support of the ICS at the Company level or the Incident Commander at the regional level. With a finite workforce, employees may be called upon to support areas outside their normal job assignments with appropriate training. In addition, emergency response exercises are executed annually, so employees gain practice in the use of the plan, as well as test the plan for effectiveness. The Company participates in regional exercises to train employees and exercise the Emergency Management Plan. Liberty CalPeco will also participate in emergency exercises and training with state and regional OES and county emergency offices.

Liberty CalPeco will conduct an exercise annually using the procedures in its Emergency Management Plan. If the plan is used during the 12-month period in responding to an event or major outage, then there is no requirement to conduct an exercise for that 12-month period. Liberty CalPeco will annually evaluate its response to an exercise or major outage event. The post-event evaluation of the exercise or a major outage will be reported to the California Public Utilities Commission. Liberty CalPeco will annually train designated personal in preparation for emergencies and major outages. The training will be specifically designed to overcome problems identified in the evaluations of responses to a major outage or exercise and shall reflect relevant changes to the Emergency Management Plan. Liberty CalPeco will maintain training records for training provided to employees following its evaluation of a major outage or emergency exercise.

Liberty CalPeco will provide a minimum of 10 days' notice of its annual exercise to appropriate state and local authorities, public safety partners, the California Public Utilities Commission, state and regional offices of the OES or its successor, the California Energy Commission, and emergency offices of the counties in which exercise is to be performed. The next exercise is scheduled for June 23, 2022. Liberty CalPeco will also participate in other emergency exercises designed to address problems on electric distribution facilities or services, including those emergency exercise of the state and regional offices of the OES or its successor, and county emergency offices. Exercises will be conducted following the Homeland Security Exercise and Evaluation Program (HSEEP) as taught by Cal OES or FEMA's Emergency Management Institute. The exercise planning process will include public safety partners.

Redeployment Plan: The District Operations and Engineering Manager is responsible to immediately assign resources to the damage assessment process during emergencies and major outages. The additional personnel selected to perform damage assessment in lieu of their normal duties include the following positions: electric troubleshooter, working foreman, inspector, lineman, field services, supply chain, project coordinators, planners, and vegetation management.

The types of training provided to the above personal include the following:

- Assessor and safety standby trainings
- Avalanche training
- Abbreviated S-130 training

- Emergency preparedness in the home
- CPR, AED, and first aid
- Fire extinguisher training
- Grounding
- Emergency Management Plan review

Emergency Management Team Training: The following training is required for every member of the Emergency Management Team:

- IS-100.C: Introduction to the Incident Command System, ICS 100
- IS-200.C: Basic Incident Command System for Initial Response
- Participate in at least one Tabletop Exercise or Lessons Learned Post Mortem on a yearly basis

10.0 Recordkeeping

Recordkeeping is essential to all programs especially the EMP. All training, program elements, comprehensive emergency plans, exercises, debriefing, corrective action and evaluations must all be documented and accessible.

Records are retained for the following reasons:

- Due diligence
- Training (lessons learned)
- Regulatory requirements

All electronic communication, such as emails, meeting minutes, resource plans, and incident progress reports will be submitted to the local internal emergency mailbox. Copies of these reports will also be submitted to Corporate Headquarters. Retention of these records is critical as they will be examined during debriefing and corrective action exercises.

Liberty Utilities

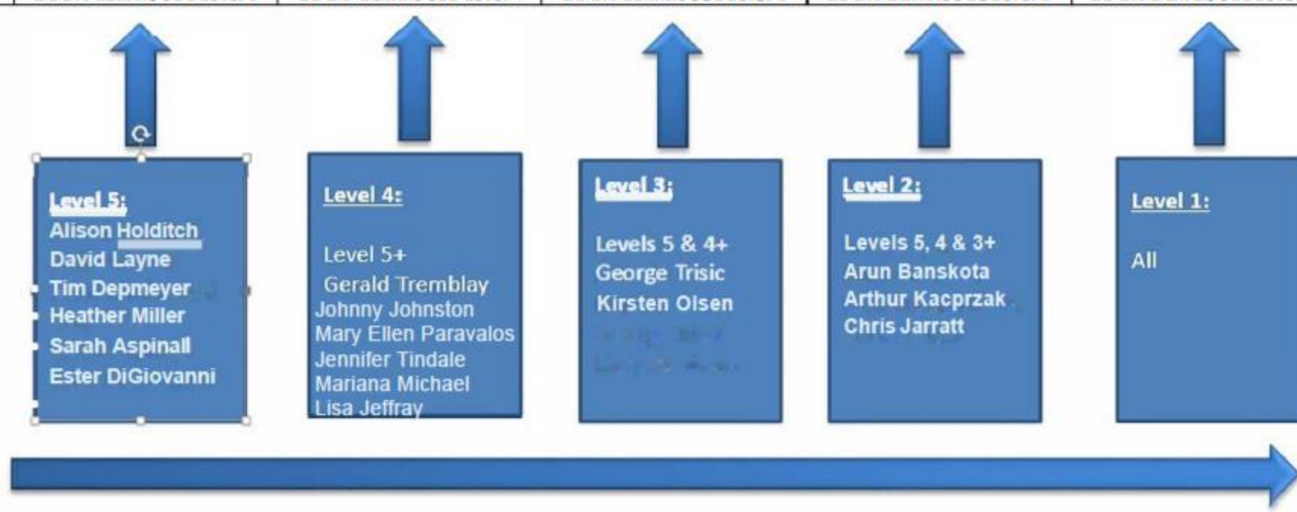
TABLE 2

Operating Conditions and Storm Levels

Storm Event Level	Operating Condition	Expected % of Customers w/o Service & Duration (1)	Expected Number of Trouble Locations / Devices (2)	Expected Number & Types of Crews	Typical Event Frequency	Weather Indices: Snow (wet / Ice inches)	Weather Indices: Accretion (inches)	Weather Indices: Tree Foliage: Leaves on	Weather Indices: Tree Foliage: Leaves off	Weather Indices: Wind Impact (mph)	Weather Indices: Wind Only (mph)	Communication Characteristics
5	Small Impact Event (Localized Response Conditions)	≥ 2,500 & < 4,499 customers AND >1 & <12 hour ERT for full system service restoration	0 - 4 Locations or Devices of Trouble	Normal activity, daily internal crew assignments.	5 - 75 times per year	≤ 2"	< 0.25	✓		≤ 25	< 25 Gusts to 25	• Crisis attracts little or no attention • Public and/or media are virtually unaware • email notification to **DL ON Oakville 911 Level 5**
						≤ 4"	< 0.50	✓		≤ 10		
4	Moderate Impact Event (Heightened Alert)	≥ 4,500 & <9,999 customers AND >12 & < 24 hour ERT for full system service restoration	2 - 10 Locations or Devices of Trouble	Normal activity, daily internal crew assignments. Possible crew transfer between areas. Utility Contractor crews (overhead line and tree) limited to normal daily complement, as needed.	5 - 15 times per year	≤ 6"	< 0.25	✓	✓	≥ 25	15 - 25 Gusts to 45	• Crisis situation may/may not have occurred; the situation is attracting slow but steady media coverage • The public at large is aware of the situation/event but is attracting very little attention • email notification to **DL ON Oakville 911 Level 4**
						≤ 8"	0.25 - 0.50	✓	✓	15 - 25		
						≤ 10"	0.50 - 0.75	✓	✓	≤ 10		
3	Serious Impact Event (Enhanced Support)	≥ 10,000 & ≤ 19,999 customers AND > 24 hour ERT for full system service restoration	3 - 15 Locations or Devices of Trouble	Regional or System ICS may be initiated and Regional EOC's may be opened. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.	0 - 5 times per year	≤ 6"	0.10 - 0.25	✓	✓	≥ 35	35 - 45 Gusts to 55	• Crisis causes growing attention from local and regional media • Affected and potentially affected parties threaten to talk to the media • email notification to **DL ON Oakville 911 Level 3**
						≤ 8"	0.25 - 0.50	✓	✓	25 - 35		
						≤ 10"	0.50 - 0.75	✓	✓	15 - 25		
						≤ 12"	0.75 - 1.00	✓	✓	< 15		
2	Major Impact Event (Comprehensive Support)	≥ 20,000 to <50% customers AND > 24 hour ERT for full system service restoration	> 5 Locations or Devices of Trouble	Regional or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.	Once every 1 to 10 Years	≤ 12"	0.25 - 0.50	✓	✓	≥ 35	45 - 55 Gusts to 75	• Media are reaching out to employees and non-communication staff for information about the crisis • Broadcast and print media are on-site for live coverage • In addition to the media, stakeholders and community partners are present at site • email notification to **DL ON Oakville 911 Level 2**, with phone call per protocol to confirm receipt
						≤ 14"	0.50 - 0.75	✓	✓	25 - 35		
						≤ 16"	0.75 - 1.00			15 - 25		
						≤ 18"	1.00 - 1.50			< 15		

LU CA Electric Emergency Incident Levels and Classification Guidelines

Classifications	Level 5: Small Impact Event	Level 4: Moderate Impact Event	Level 3: Serious Impact Event	Level 2: Major Impact Event	Level 1: Catastrophic Impact Event
Expected # of Customers w/o Service & Duration (1)	> 2,500 & < 4,499 customers AND > 1 hr & <12 Hr ERT for full service restoration	> 4,500 & < 9,999 customers AND > 12 hr & < 24 Hr ERT for full service restoration	> 10,000 & < 19,999 customers AND >24 hour ERT for full system service restoration	> 20,000 to < 50% customers AND > 24 hour ERT for full service restoration	> 50% customer interruptions OR > 72 hour of ERT for full service restoration
Expected Number & Types of Crews	Normal activity, daily internal crew assignments.	Normal activity, daily internal crew assignments. Possible crew transfer between areas. Utility Contractor crews (overhead line and tree) limited to normal daily complement, as needed	Regional or System ICS may be initiated and Regional EOC's may be opened. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.	Regional or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.	Regional and/or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed. CPUC notification required.
Email	DL ON Oakville 911 Level 5	DL ON Oakville 911 Level 4	DL ON Oakville 911 Level 3	DL ON Oakville 911 Level 2	DL ON Oakville 911 Level 1



https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R18 12005

Attachment I

PSPS Threshold Exceedance Frequency Analysis

Table I.1-1: Annualized Line Mile Hours Exceeding Joint FFWI / Wind Gust Criteria by Conth.

January

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	1,741	1,107	398	106	18	6
	50	952	652	243	65	13	3
	55	485	353	130	28	7	3
	60	242	189	72	14	6	2
	65	108	84	33	5	3	2
	70	29	25	16	1	0	0

February

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	1,410	1,109	783	513	324	140
	50	880	736	561	382	246	110
	55	501	433	355	262	187	80
	60	321	281	236	180	136	52
	65	191	165	140	110	88	37
	70	98	87	76	56	45	26

March

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	759	607	400	276	163	86
	50	433	377	282	213	142	76
	55	253	242	199	156	112	70
	60	174	169	152	123	94	64
	65	113	111	99	83	70	52
	70	82	81	79	67	57	44

April

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	593	375	132	14	1	0
	50	333	252	104	11	1	0
	55	150	121	56	8	0	0
	60	61	49	19	1	0	0
	65	34	30	9	0	0	0
	70	21	18	4	0	0	0

May

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	392	220	156	51	11	0
	50	236	147	114	37	5	0
	55	128	92	79	28	2	0
	60	44	38	34	11	2	0
	65	11	10	10	5	0	0
	70	0	0	0	0	0	0

June

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	339	144	45	11	1	0
	50	173	93	35	10	0	0
	55	86	50	25	9	0	0
	60	36	22	13	6	0	0
	65	20	13	6	4	0	0
	70	8	7	5	4	0	0

July

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	52	11	2	0	0	0
	50	46	11	2	0	0	0
	55	30	10	2	0	0	0
	60	21	9	2	0	0	0
	65	13	7	2	0	0	0
	70	2	1	1	0	0	0

August

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	15	3	2	1	0	0
	50	10	2	1	1	0	0
	55	7	2	1	1	0	0
	60	4	2	1	1	0	0
	65	3	1	1	1	0	0
	70	2	1	0	0	0	0

September

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	230	91	33	6	1	0
	50	136	61	25	5	1	0
	55	61	40	19	3	1	0
	60	25	15	5	3	1	0
	65	10	6	2	1	0	0
	70	4	2	1	0	0	0

October

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	740	511	281	125	65	15
	50	431	281	163	85	43	8
	55	224	152	102	51	26	4
	60	103	66	49	27	19	0
	65	48	36	26	15	13	0
	70	20	13	9	6	6	0

November

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	1,631	1,119	742	463	265	182
	50	1,190	894	587	407	249	178
	55	907	735	515	365	241	176
	60	701	615	452	326	227	165
	65	527	485	384	291	204	155
	70	390	366	302	242	176	139

December

		Wind gust (mph)					
		35	**40**	**45**	**50**	**55**	**60**
FFWI	**45**	2,716	1,970	1,140	498	161	15
	50	1,991	1,517	966	453	155	14
	55	1,243	1,014	668	336	137	10
	60	783	645	439	237	106	7
	65	499	406	290	153	68	4
	70	312	253	184	90	30	2

Figure I-1-1: Hours per year where FFWI exceeds 50 and wind gust exceeds 40 mph.

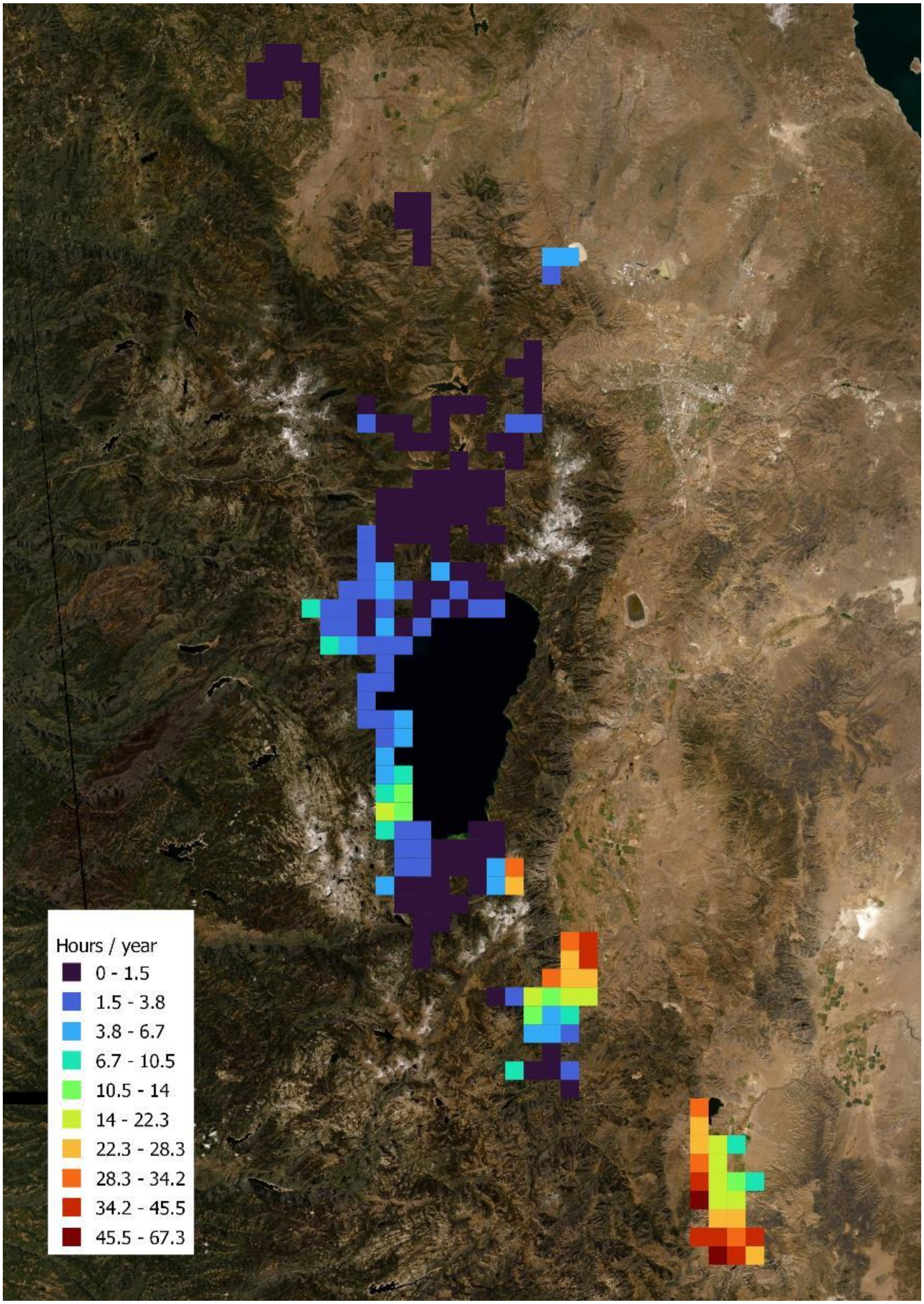


Figure I-1-2: Hours per year where FFWI exceeds 60 and wind gust exceeds 45 mph.

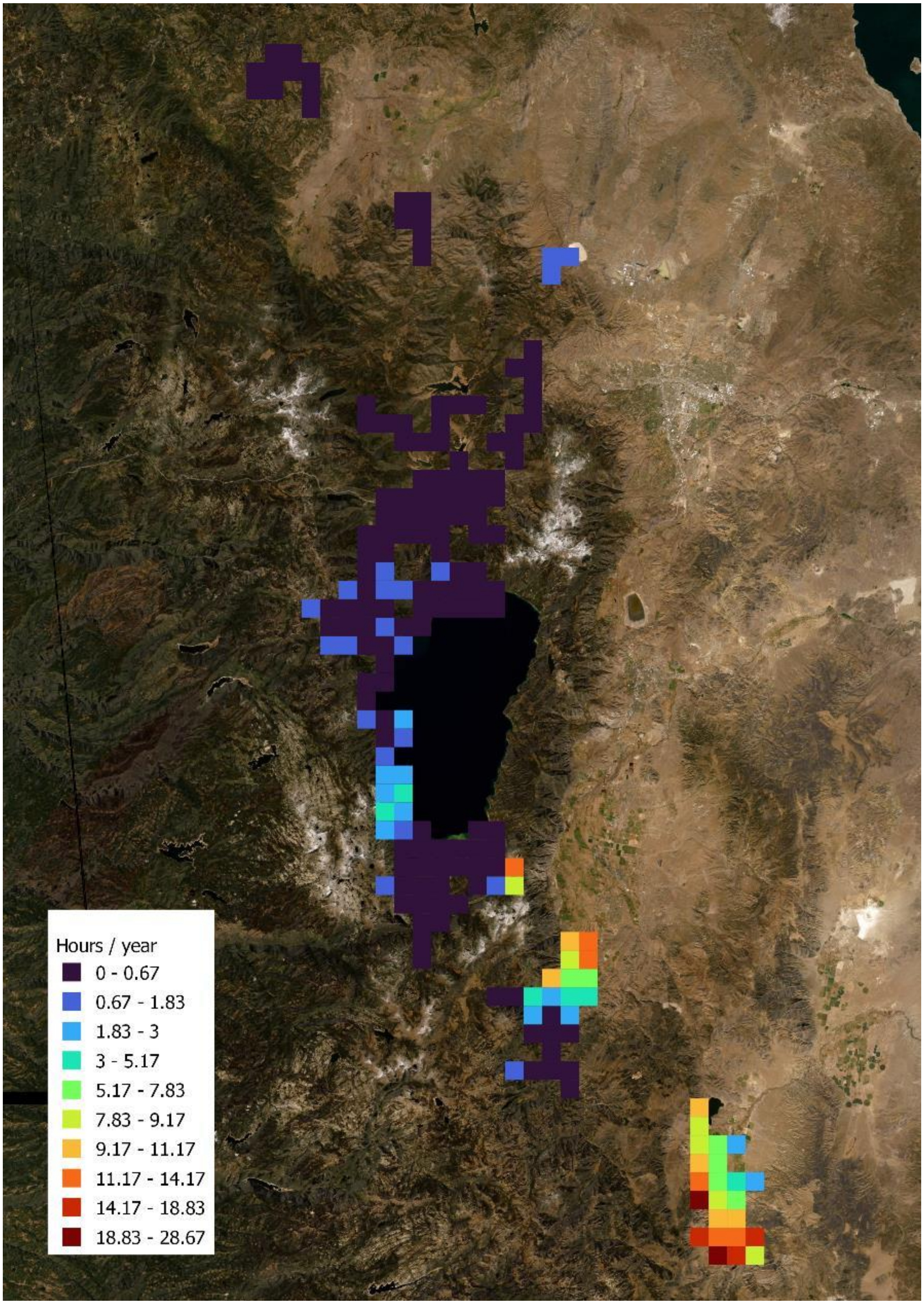


Figure I-1-3: Number of days per year where 3 or more hourly records jointly exceed wind gust of 40 mph and FFWI of 50.

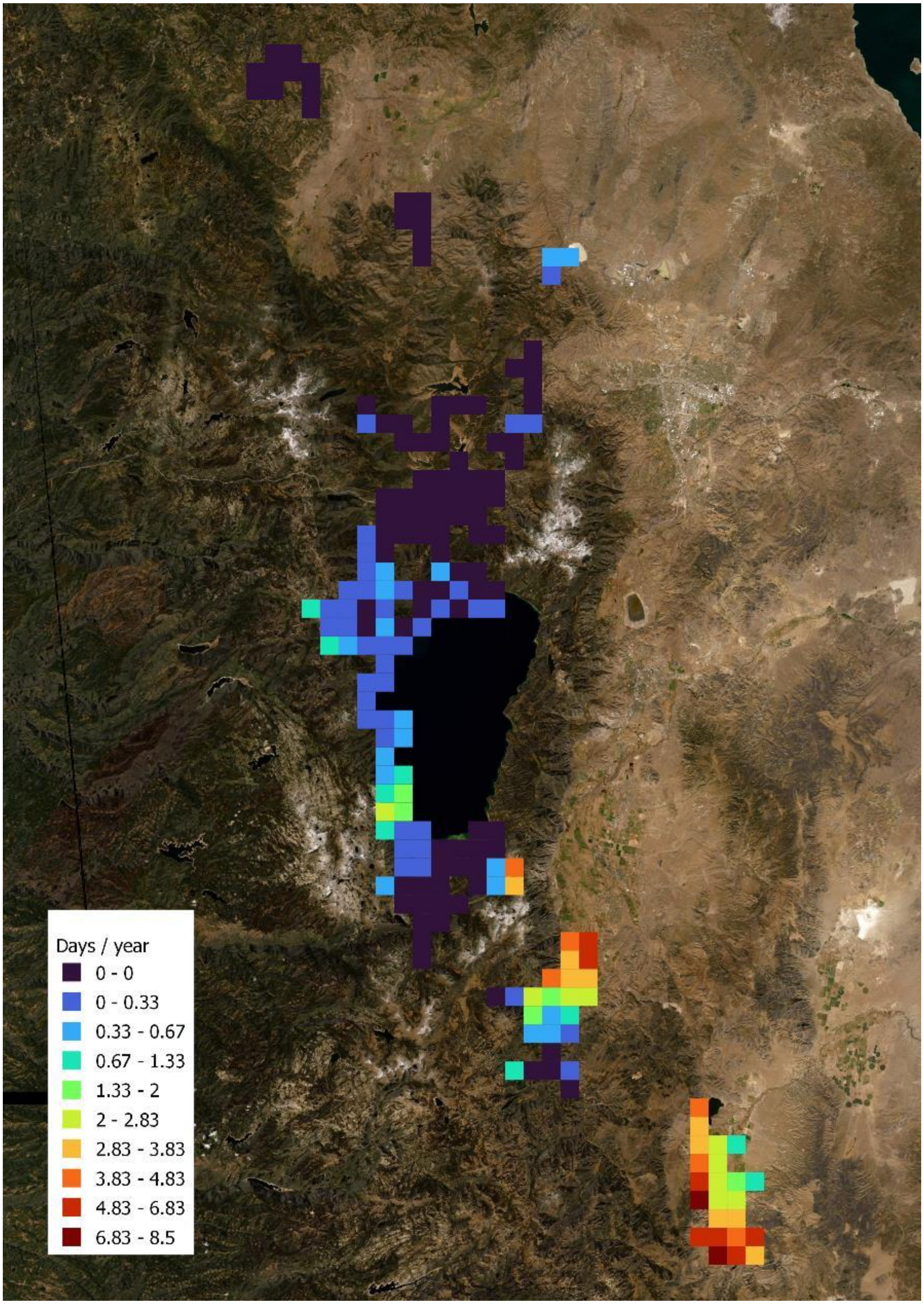
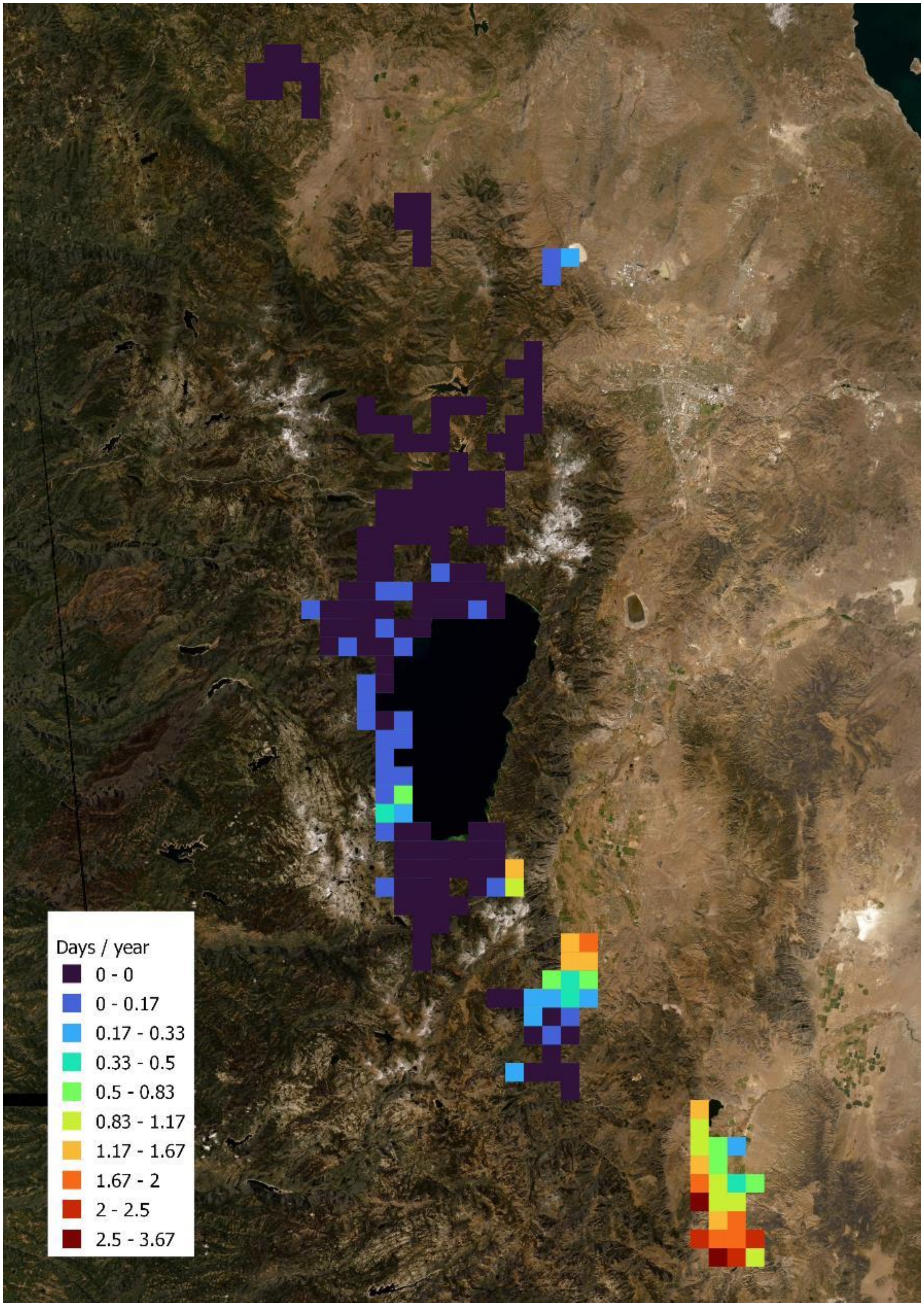


Figure I-1-4: Number of days per year where 3 or more hourly records jointly exceed wind gust of 45 mph and FFWI of 60.



Attachment J

Liberty Circuit Risk Assessment

Liberty's Circuit Risk Assessment below starts with an inventory of all circuit miles in Liberty's service territory by Reax risk category. This determines which circuit miles are "High" and "Very High" wildfire risk. The "High-Risk Score" column is the focus of the Circuit Risk analysis. This column applies scaled multipliers the high and very high-risk circuit miles, giving more weight to higher risk, and takes that value as a proportion of the total miles in the circuit. The result is a score that ranks circuits by how many risky circuit miles they contain. Finally, a qualitative rating is given to the circuits based on their High-Risk Score, with the following thresholds.

Table J.1-1: Liberty Circuit Risk Assessment

	Circuit Miles By Reax Risk							
Circuit	**N/A**	**Low**	**Moderate**	**High**	**Very High**	**Total**	**High Risk Score**	**Risk Rating**
MEY3300					52.59	52.59	262.97	Very High
MULLER1296				43.62		43.62	109.04	Very High
MEY3400		13.62	17.32	5.32	18.11	54.37	103.84	Very High
MEY3500		11.12			15.97	27.09	79.84	Very High
GLS7400		9.71	3.66	19.34		32.71	48.34	Very High
625 - 60kV (Tahoe City-Kings Beach)		0.33	2.36	12.20		14.90	30.51	High
132 - 120 KV (Truckee-Squaw Valley)		4.68	5.71	12.10		22.50	30.26	High
MEY3100		11.86		0.15	5.51	17.52	27.92	High
SQV7201			1.09	10.78		11.88	26.95	High
MEY3200		16.54			4.96	21.50	24.80	High
111 - 120 KV (Meyers-Buckeye)				3.91	2.85	6.76	24.04	High
HOB7700				8.81		8.81	22.03	High
640 - 60kV (Meyers-Stateline)		3.49		0.61	3.90	8.00	21.02	High
TRK7204				6.80		6.80	17.01	Moderate-High
TRK7202		1.45	4.28	6.35		12.07	15.87	Moderate-High
BKY4201			3.44	5.88		9.32	14.69	Moderate-High
SQV8200				4.93		4.93	12.32	Moderate-High
CAL204			0.60	4.33		4.93	10.82	Moderate-High
650 - 60kV (Truckee-Kings Beach)		3.72	1.53	4.11		9.36	10.27	Moderate-High
188 - 60kV (Kings Beach - Northstar)				3.29		3.29	8.23	Moderate-High
RUS7900				3.27		3.27	8.19	Moderate-High
629 - 60kV (Squaw Valley-Tahoe City)		0.33	2.81	2.04		5.18	5.09	Moderate
TRK7203		7.45	0.37	1.98		9.81	4.96	Moderate
STL3101		14.44		1.35		15.79	3.36	Moderate
BKY5100			0.92	1.31		2.23	3.28	Moderate
TAH7200		0.44	3.72	0.47		4.63	1.18	Moderate
KBS2800				0.42		0.42	1.06	Moderate
NST8600				0.11		0.11	0.26	Low
SMP8700	0.24					0.24	0.00	Low
T634	0.15	0.33				0.48	0.00	Low
160 - 120 KV (Round Hill-Cal Border)	0.15	0.39				0.54	0.00	Low
TAH7300		56.80				56.80	0.00	Low
TPZ1261		39.11	16.07			55.18	0.00	Low
BKY5200		11.75	11.53			23.28	0.00	Low
TAH5201		10.15	11.11			21.26	0.00	Low
POR32		20.77	0.06			20.83	0.00	Low
STL3501		13.79				13.79	0.00	Low
TAH7100		7.57	5.69			13.26	0.00	Low
POR31		13.11				13.11	0.00	Low
608 - 60kV (Truckee-Washoe)		6.56	3.73			10.29	0.00	Low
BKY4202		7.85	1.39			9.23	0.00	Low
WSH201			7.08			7.08	0.00	Low
SRB51			6.80			6.80	0.00	Low
608 - 60kV (Truckee-North Truckee-Glenshire)		5.45	0.86			6.31	0.00	Low
619 - 60kV (Portola-Truckee)		0.11	6.01			6.12	0.00	Low
CEM41		3.71	1.93			5.64	0.00	Low
GLS7600		0.04	5.21			5.24	0.00	Low
CEM42		3.31				3.31	0.00	Low
SLK257			2.99			2.99	0.00	Low
STL2300		2.91				2.91	0.00	Low
SQV8300			1.27			1.27	0.00	Low
HIRSCHDALE LINE TIE			0.66			0.66	0.00	Low
STL2200		0.31				0.31	0.00	Low
LOY619		0.05				0.05	0.00	Low
TRUCKEE SWITCH STATION-DONNER SUMMIT SWITCH		0.04				0.04	0.00	Low
MARBLE BLUFF TAP			0.01			0.01	0.00	Low
GLENSHIRE TAP			0.01			0.01	0.00	Low

Table J.1-2: Tree Span Risk