Rocky Mountain Power
Docket No. 20-035-04
Witness: Curtis B. Mansfield

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Curtis B. Mansfield

October 2020

Q. Are you the same Curtis B. Mansfield that filed direct testimony on behalf of PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company") in this proceeding?

A. Yes.

I. PURPOSE OF REBUTTAL TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to provide an update on the Company's Wildland Fire Protection Plan ("Plan") since the Company's initial filing in this case and to respond to the Office of Consumer Services ("OCS") witness Ms. Donna Ramas' proposed adjustment to the Utah Advanced Meter Infrastructure ("AMI") Project.

II. WILDLAND FIRE PROTECTION PLAN

Q. Have there been updates to the costs in the revenue requirement in this case associated with the Plan since your direct testimony?

A. Yes. As stated in my direct testimony, at the time of filing the case in early May 2020, the Company was in the process of finalizing its Wildland Fire Protection Plan in preparation for the June 1, 2020 submission to the Public Service Commission of Utah ("Commission"). A copy of the final Plan is included with my testimony in this docket as Exhibit RMP___(CBM-1R).[1] At the time of filing this rebuttal testimony, the Commission has not issued an order approving the Plan; however, no party objected to the Commission approving the plan.[2] The Company is updating the revenue requirement in this case to reflect the final costs of the Plan.

[1] Rocky Mountain Power's Utah Wildland Fire Protection Plan, Docket No. 20-035-28 (June 1, 2020).
[2] The Office of Consumer Services conditioned their recommendation upon the Company meeting the statutory requirement of Utah Code Section 54-24-201(3)(c).

Q. What are the cost updates to the Plan?

A. As I explained in my direct testimony, the 2020 and 2021 Wildland Fire Mitigation costs are included in the rates requested by the Company in this proceeding. The updated costs in Table 1 below reflect the refined program costs filed in the Company's Utah Wildland Fire Protection Plan on June 1, 2020.

Table 1: Wildfire Mitigation Program Capital Costs

	2020 Capital Costs	**2021 Capital Costs**	**2022 Capital Costs**
Direct Filing Total Costs	$46,258,000	$49,857,500	$50,157,834
Utah Wildland Fire Protection Plan HB66 Costs	$37,381,417	$50,691,549	$50,134,094

The Plan costs were updated to reflect the availability of contract resources, material restrictions and permitting delays. Wildfire damage across the West, mainly California, limited the availability of contract resources. Additionally, internal and external construction resources assisted with storm damage repairs, including providing mutual aid to impacted areas outside of Utah. Material availability has been impacted by an increase in wildfire projects in the Western States as well as reductions in product availability due to manufacturing facilities being suspended or shut down by COVID-19. With wildfires still active in California, Oregon and Washington, the Company anticipates there may be additional delays in the planned work for 2020 resulting in an additional reduction of close to $12 million, which would require the plan to be rephased through 2026. Mr. Steven R. McDougal provides the details of how the updated rebuttal costs have been included in the requested revenue requirement.

III. AMI PROJECT

Q. What does the OCS propose with respect to the AMI project?

A. OCS witness Ms. Ramas recommends the AMI project be completely removed from the test period revenue requirement in this case because the project has been delayed and is now anticipated to be completed after the end of the test period.

Q. Ms. Ramas, based on responses to data requests, anticipates only $12 million of the Utah AMI project to be placed into service on an average test year basis. Do you agree that this warrants a complete removal of the project from the test period?

A. No. As explained in the response to OCS data request 5.16, the Company expects the AMI project to be completed by the end of 2022. In response to OCS data request 11.1(b), the Company noted the *completion* of the project was delayed until the end of 2022 due to cybersecurity concerns, vendor-recommended technology changes and COVID-19. However, as shown in the workbook attached to the response to OCS data request 11.1 and included here as Exhibit RMP___(CBM-2R), the Company expects to place approximately $46.8 million into service in the test period. While it is true that the entire AMI project will not be completed until 2022, the entire project does not need to be complete before the assets placed into service are used and useful in providing some of the benefits that I outlined in my direct testimony. The field network will be substantially complete by the end of 2021 and the system will begin reading the existing automatic meter reading meters soon after. Ms. Ramas gives no good reason not to allow the Company to update to the current forecast instead of simply removing the entire project from the case. The Company has updated the revenue requirement requested in this case to reflect the current forecast, which is a reduction to the revenue requirement as discussed by Mr. McDougal.

Q. Ms. Ramas points out that in the response to OCS data request 11.2, the Company stated that the eight benefits identified in my direct testimony are anticipated to begin in January 2023. Please clarify.

A. The eight benefits I listed in my direct testimony are:

1. Provide customers access to data regarding their hourly energy consumption, which will enable them to make more informed energy decisions;
2. Provide better customer service by giving the Company's customer service representatives information necessary to provide accurate responses to customer inquiries and facilitate customer complaint resolution;
3. Reduce the number of estimated bills by providing the Company with actual meter data regardless of physical access barriers, bad weather delays, or other factors that can impede physical meter reading and give rise to estimated billing;
4. Perform remote connect and disconnect at sites with smart meters that will enable service to be turned on and off on a near real-time basis without deploying employees to customers' premises;
5. Detect, react, and troubleshoot power outages in a more timely manner, without the need to wait for an outage notification directly from the customer;
6. Obtain analytic information at sites with smart meters, such as temperature, voltage, and power quality data, which can be used to assess system performance and improve service to customers;

7. Introduce efficiencies related to automation that reduce the cost to obtain meter reads and perform service connects and disconnects; and
8. Enhance safety and reduce carbon dioxide emissions through the reduction of vehicles used for drive-by meter reading operations.

While it is true that completion of the project will allow all of the benefits to be deployed, it is also true that customers will experience many of these benefits before completion. For example, the first three benefits stated above are scheduled to be available to residential customers with new AMI meters by the end of 2021 when the Gen5 field network is completed in their neighborhoods. As stated in the response to OCS data request 11.2c, full AMI data availability, required for the remaining benefits, is anticipated to begin in January 2023 after all AMI meters have been installed.

Q. Did the OCS raise other issues with the AMI project in its testimony in the cost of service and pricing phase of this case?

A. Yes. In addition to the arguments raised by Ms. Ramas on behalf of the OCS in the revenue requirement phase of this case, OCS witness Mr. Ron Nelson presents additional recommendations and arguments with respect to the AMI project in his direct testimony that was filed in the cost of service and pricing phase on September 15, 2020. It is unclear to the Company why the OCS decided to split its arguments against the Company's AMI project between two phases of testimony; however, for consistency I will address these additional issues in my rebuttal testimony in the cost of service and pricing phase of this proceeding.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(CBM-1R)
Docket No. 20-035-04
Witness: Curtis B. Mansfield

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Curtis B. Mansfield

RMP Utah Wildland Fire Protection Plan

October 2020

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

June 1, 2020

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

RE: Docket No. 20-035-28
Rocky Mountain Power's Utah Wildland Fire Protection Plan

Pursuant to Utah Code § 54-24-201(3), PacifiCorp, d.b.a. Rocky Mountain Power, ("the Company") hereby submits its comprehensive wildland fire projection plan.

The Company respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred):	datarequest@pacificorp.com utahdockets@pacificorp.com jana.saba@pacificorp.com tim.clark@pacificorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward

Joelle Steward
Vice President, Regulation

Enclosures

Utah Wildland Fire Protection Plan

June 1, 2020

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Definition of Common Acronyms

ANSI	American Nation Standards Institute
APLIC	Avian Power Line Interaction Committee
APP	Avian Protection Plan
BLM	Bureau of Land Management
BMP	Best Management Practices
CONDFRAY	Conductor Frayed or Damaged
EEI	Edison Electric Institute
ELMFIRE	Eulerian Level Set Model for Fire Spread
EOC	Emergency Operations Center
ESF	Emergency Support Functions
FFSL	Utah Division of Forestry, Fire and State Lands
FFWI	Fosberg Fire Weather Index
FHCA	Fire High Consequence Area
FPI	Facility Point Inspection
GIS	Geographic Information System
GUYMARK	Missing or broken guy marker
ICP	Incident Command Post
ICS	Incident Command System
IVM	Integrated Vegetation Management
JIS	Joint Information System
kV	Kilovolt
MBTA	Migratory Bird Treaty Act
MVCD	Minimum Vegetation Clearance Distance
NARR	North American Regional Reanalysis
NESC	National Electric Safety Code
NGO	Nongovernmental organization
NIMS	National Incident Management System
O&M	Operations & Maintenance
OH	Overhead
PSPS	Public Safety Power Shutoff
T&D	Transmission and Distribution
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
WITS	Wildlife Incident Tracking System
WPP	Wildlife Protection Plan
WRF	Weather Research and Forecasting
WRI	Watershed Restoration Initiative
ZOP	Zone of Protection

Introduction and Cost Summary

Rocky Mountain Power is submitting this wildland fire protection plan under UTAH CODE § 54-24-201. Due to the growing threat of catastrophic wildfire in the western United States, Rocky Mountain Power has developed a comprehensive plan for wildfire mitigation efforts in all of its service territories. This plan specifically guides the mitigation strategies that will be deployed in Utah. These efforts are designed to reduce the probability of utility related wildfires, as well as to mitigate the damage to Rocky Mountain Power facilities because of wildfire.

Wildfire has long been an issue of notable public concern. Due to the potential for fire caused by sparks emitted from electrical facilities, wildfire mitigation is of particular concern for electric utilities. Trends in the growth of wildfire size and intensity have magnified these concerns. Despite efforts of fire suppression agencies and increased suppression budgets, wildfires have continued to grow in number, size and intensity. Increased human development in the wildland-urban interface, the area where people (and their structures) are intermixed with, or located near, substantial wildland vegetation, has exacerbated the costs of wildfire damage in terms of both harm to people and property damage. A wildfire in an undeveloped area can have ecological consequences – some positive, some negative – but a wildfire in an undeveloped area will not, generally, directly affect large numbers of people. A wildfire engulfing a developed area, on the other hand, has catastrophic consequences on people and property.

The relationship between wildfire and public utilities has been brought to the forefront by recent developments in California, resulting in substantial loss of human life and property damage.[1] Although Utah does not have the same degree of wildfire risk as some other places (such as California due, among other factors, to its unique Santa Ana winds), the wildfire risk in Utah is still substantial. The general trend toward larger and more destructive fires is not unique to California. In 2018, for example, multiple western states had wildfires exceeding 100,000 acres, including Oregon (Klondike Fire and Boxcar Fire), Nevada (Martin Fire and Sugarloaf Fire), and Utah (Pole Creek Fire).

The state of Utah has recognized and emphasized the risk of wildfire for many years. For example, following the difficult 2012 wildfire season, the state of Utah responded with the publication of the Catastrophic Wildfire Reduction Strategy, which recognizes the long-term trend toward larger and more destructive wildfires. Since 2012, Utah has witnessed a growing risk of wildfire. Utah experienced one of its worst, if not very worst, wildfire seasons in 2018, including the Trail Mountain Fire, the Dollar Ridge Fire, and the Pole Creek Fire. Due to a particularly wet year in 2019, with precipitation well spread through the warmer months, Utah had a relatively low wildfire impact year in 2019. A low-impact year, however, can add to the fuel inventory and increase the risk during subsequent seasons. Vigilance will be warranted in

[1] The October 2017 "firestorm" in northern California; the December 2017 Thomas Fire north of Los Angeles, California; the July 2018 Carr Fire near Redding, California; and the November 2018 Camp Fire, which decimated the city of Paradise, California.

2020 and beyond. Accordingly, Rocky Mountain Power is committed to making long-term investments to reduce the chances of catastrophic wildfire.

The preventative measures described in this wildland fire protection plan include proactive investments to construct, maintain and operate electrical lines and equipment in a manner that minimizes the risk of catastrophic wildfire. In evaluating which engineering, construction and operational strategies to deploy, Rocky Mountain Power was guided by the following core principles:

- Frequency of ignition events related to electric facilities can be reduced by engineering more resilient systems that experience fewer fault events.
- When a fault event does occur, the impact of the event can be minimized using equipment and personnel to isolate the fault event.
- Systems that facilitate situational awareness and operational readiness are central to mitigating fire risk and its impacts.
- A successful plan must also consider the impact on Utah customers and Utah communities, in the overall objective to provide reliable, safe and affordable electric service.

The strategies embodied in this plan are evolving and are subject to change. As new analyses, technologies, practices, network changes, environmental influences or risks are identified, modifications may be incorporated into future iterations of the plan, as contemplated in UTAH CODE § § 54-24-201(3)(a)(ii).

Plan Cost Summary

The following tables present a summary of the planned mitigation activities, the total estimated costs and the planned timeframe for implementation.

Table 1. Rocky Mountain Power's Utah Wildland Fire Protection Implementation Summary – Capital

Incremental Capital in $ millions	2020	2021	2022	2023	2024	2025	2026	Total
Mitigation Program								
Advanced Protection and Control	$ 3,253,786	$ 3,003,944	$ 2,255,000	$ 955,000	$ 265,000	$ 265,000	$ 265,000	**$ 10,262,730**
Environmental	$ 241,728	$ 232,128	$ 232,128	$ 232,128	$ 232,128	$ 232,128	$ 232,128	**$ 1,634,496**
Inspect and Correct	$ 1,000,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	**$ 10,000,000**
Operational Practices	$ 2,882,769	$ 1,013,750						**$ 3,896,519**
Situational Awareness	$ 445,000	$ 240,000	$ 150,000	$ 112,000			$ 112,000	**$ 1,059,000**
System Hardening	$ 29,558,134	$ 44,701,727	$ 45,996,966	$ 37,651,673	$ 25,749,652	$ 20,009,524	$ 10,029,690	**$ 213,697,366**
Total	**$ 37,381,417**	**$ 50,691,549**	**$ 50,134,094**	**$ 40,450,801**	**$ 27,746,780**	**$ 22,006,652**	**$ 12,138,818**	**$ 240,550,111**

Table 2. Rocky Mountain Power's Utah Wildland Fire Protection Implementation Summary – O&M

Incremental O&M in $ millions	2020	2021	2022	2023	2024	2025	2026	Total
Mitigation Program								
Vegetation Inspections, Mitigation, Pole Clearing – Distribution	$ 1.5	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	**$ 9.1**
Vegetation Inspections, Mitigation, Pole Clearing – Transmission	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	**$ 1.8**
FHCA Inspections	$ 0.8	$ 0.9	$ 0.9	$ 0.9	$ 1.0	$ 0.9	$ 0.9	**$ 6.3**
Condition Corrections – Distribution	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	**$ 7.7**
Condition Corrections – Transmission	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	**$ 0.5**
Weather Station Maintenance, Tool Development, Community Meetings, Advertising – Other	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	**$ 1.3**
Fault Anticipator - Other	$ -	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	**$ 0.6**
Environmental – Wildlife Protection Program, Habitat Enhancements, Other – Distribution	$ 0.1	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	**$ 2.5**
Environmental – Wildlife Protection Program, Habitat Enhancements, Other – Transmission	$ 0.0	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	**$ 0.4**
Patrolling Costs, Field Response (PSPS) – Other	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	**$ 1.4**
Alert Wildfire Cameras – Other	$ 0.1	$ 0.3	$ 0.3	$ 0.2	$ 0.3	$ 0.3	$ 0.2	**$ 1.5**
Wood Pole Wrap	$ -	$ 0.1	$ -	$ -	$ -	$ -	$ -	**$ 0.1**
Total	**$ 4.3**	**$ 5.0**	**$ 4.8**	**$ 4.8**	**$ 4.9**	**$ 4.8**	**$ 4.7**	**$ 33.2**

1. Risk Analysis and Drivers

1.1. Methodology for Identifying and Evaluating Risk

This risk evaluation process employs the concept that the risk is essentially the product of the likelihood of a specific risk event times the impact of the event. The likelihood, or probability, of an event is an estimate of a particular event occurring within a given time frame. The impact of the event is an estimate of the effect when an event occurs. Impact can be evaluated using a variety of factors, including considerations centered on health and safety, the environment, customer satisfaction, system reliability, and financial implications. As discussed below, the risk analysis in this plan focuses on the potential impact in harm to people and damage to property.

1.1.1. Modeling Rocky Mountain Power's Wildfire Risk

A disruption of normal operations on the electrical network, called a "fault" in the industry, could be a possible ignition source for wildfire. Under certain weather conditions and in the vicinity of wildland fuels, an ignition can grow into a harmful wildfire, potentially even growing into a catastrophic fire causing great harm to people and property. This general relationship is shown in the Venn diagram below.

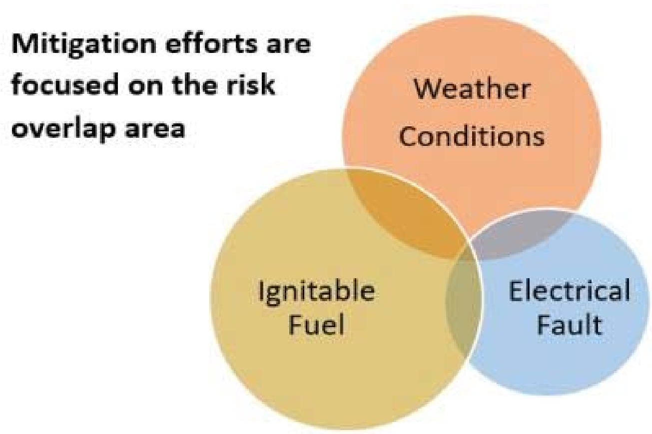

Figure 1. Utility Fire Risk Conceptual Model

Rocky Mountain Power's risk analysis first concentrates on weather conditions and ignitable fuels, to identify the geographic areas in Rocky Mountain Power's service territory at the greatest risk of catastrophic fire. The analysis also explores Utah's fire history, its recorded causes, the acreage impact of the fires, and the seasonality of fires. The analysis further considers historical outage data, reflecting the best available data regarding the potential for faults on the electrical system.

Rocky Mountain Power's analysis of the wildfire risk in Utah took advantage of a larger PacifiCorp effort across all of its service territory states.[2] In 2018 and 2019, PacifiCorp completed a wildfire risk analysis for Utah, Idaho, Wyoming, Oregon, and Washington. This effort was patterned after the methodology developed after a long and iterative process in California, in which PacifiCorp participated because of its California service territory. To take advantage of that experience, PacifiCorp engaged fire-science engineering firm REAX Engineering Inc. to identify areas of elevated wildfire risk, which were ultimately designated with the name of Fire High Consequence Areas (FHCA).

PacifiCorp and REAX first identified the general geographic areas subject to the risk analysis, which included all of PacifiCorp's service territory and a 25-mile radius study area around all PacifiCorp-owned transmission lines, as shown below:

Topography (elevation, slope, aspect) segmented into 2-km-square cells:

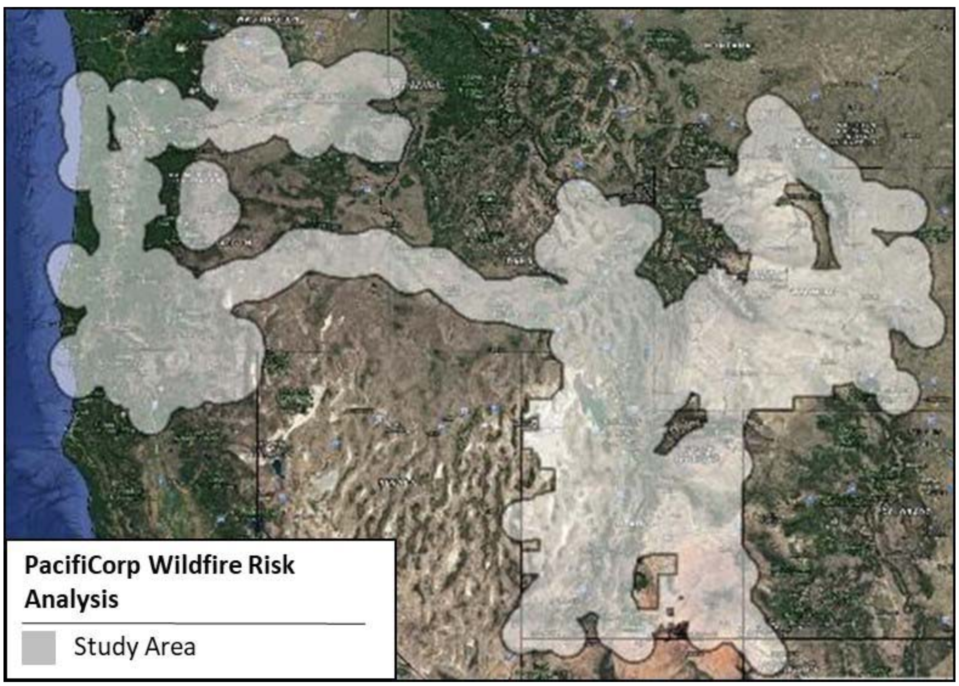

Figure 2. Study Area for Fire Risk Mapping Project

[2] Rocky Mountain Power is the division of PacifiCorp that has service territory in Utah, Idaho, and Wyoming, Pacific Power is the division of PacifiCorp that has service territory in California, Oregon, and Washington.

REAX then conducted a wildfire risk analysis on this area. REAX used the following data and processes:

1. Topography of the land, including elevation, slope and aspect
2. Fuel data (from a dataset known as LANDFIRE[3]) with 30 m pixel resolution, calibrated against one of 40 “fuel models[4],” which quantify fuel loading, fuel particle size and other quantities needed by fire models to calculate rate of spread
3. Weather Research and Forecasting (WRF), resulting in climatology derivative from North American Regional Reanalysis (NARR) with resolution at 32 km, which is a hybrid of weather modeling and surface weather observations (including temperature, relative humidity, wind speed/direction, and precipitation, weather balloon observations of wind speed/direction and atmospheric, sea surface temperatures from buoys, satellite imagery for cloud cover and precipitation).[5]
4. Historical fire weather days spanning the period from January 1, 1979 through December 31, 2017, determined by calculating the Fosberg Fire Weather Index, modified to recognize off-season moisture, as measured by Schroeder’s ember ignition probability P_{ign}.[6]
5. Estimated live fuel moisture
6. Ignition modeling, using Monte Carlo-simulated ignition scenarios
7. Fire spread modeling, Eulerian Level Set Model for Fire Spread (ELMFIRE), which is software for modeling wildland fire spread; ELMFIRE is used to run Monte Carlo-simulated burn scenarios that incorporate impacts to populations (by using the proxy of structures involved in any burn scenario, based on census tract data[7]), climatology, using spread algorithms developed in Eulerian Level Set Model for Fire Spread (ELMFIRE), conducted over a six-hour burn period, where fire type (surface, passive crown or active crown fire) in combination with flame length is critical to quantify output metrics including fire size (acres), fire volume (acre-ft) and the number of structures within the fire perimeter.

Through this process, individual blocks of geographic area, each 2 kilometer square, received a grid score corresponding to its relative wildfire risk. To establish the Fire High Consequence Area (FHCA), REAX used the prior California mapping project for calibration and assigned cell scores correlating with California statewide cell scores. This approach enabled an “apples-to-apples”

[3] https://www.landfire.gov/datatool.php
[4] https://www.landfire.gov/fbfm40.php
[5] Essentially, a weather model similar to WRF assimilates/ingests several thousand weather observations over a three-hour period and then uses that information to create a 3D representation of the atmosphere every three hours. This includes not only surface (meaning near ground level) quantities but also upper atmosphere quantities as well. The NARR dataset is available from 1979 (when modern satellites first became available) to current day (with a lag of a few weeks).
[6] This metric MFFWI, was calculated in three-hour intervals for the time period of 1979–2017, and averaged over a six-hour period, since the early hours of a large fire are significant predictors for most catastrophic fires. The largest values were extracted, which involved about 200 days of hourly climatology inputs.
[7] http://www2.census.gov/geo/tiger/TIGER2010/TABBLOCK/2010/tl_2010_06_tabblock10.zip, ftp://ftp2.census.gov/geo/tiger/TIGER2010BLKPOPHU/tabblock2010_06_pophu.zip

comparison to the results of that prior project, so that the relative degree of wildfire risk in areas of other states could be compared to the risk in areas of California. REAX then used geographic information system (GIS) software algorithm "Jenks natural breaks" to segment areas into 33 families of risk areas[8], so that all cell areas were given a score from 0 to 32, as shown in Figure 3. Cell values do not imply direct mathematical relationships, but rather indicate bins of relative catastrophic wildfire risk, when population density is factored into the weighting process.

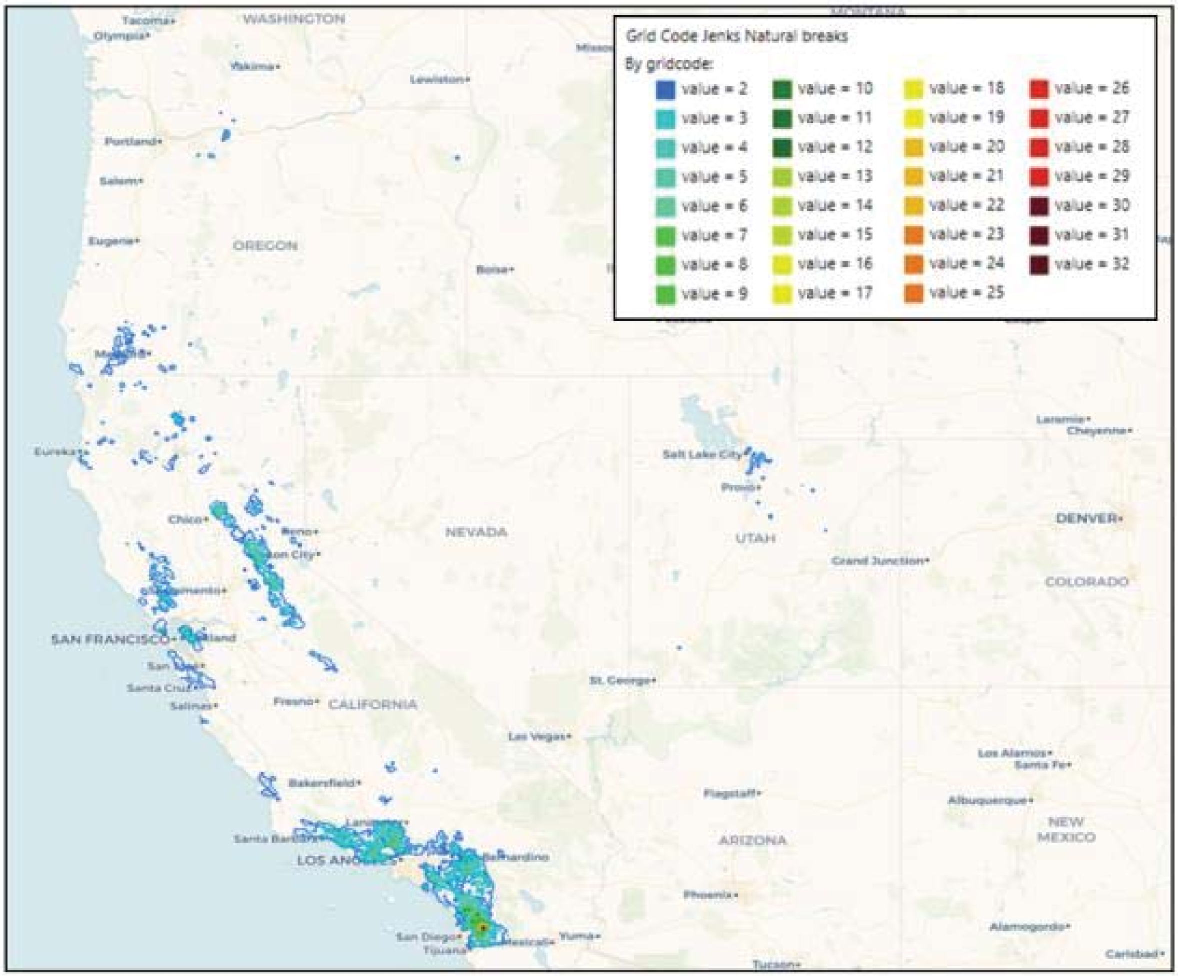

Figure 3. Grid Code of Jenks Natural Breaks

After REAX completed the computer modeling, a "ground-truthing" activity was completed by evaluating historical fire perimeters, existing Rocky Mountain Power facility equipment, and local conditions. The ground-truthing exercise generally validated the modelling performed by REAX and resulted in some relatively minor adjustments to the preliminary boundaries. Rocky

[8] https://www.spatialanalysisonline.com/extractv6.pdf

Mountain Power plans to make an annual review of the FHCA boundaries and may make adjustments, based on updated modeling, integration of other risk assessment tools, and knowledge of local conditions.

The resulting Utah FHCA, together with magnified views on certain FHCA areas, is shown in the following figures.

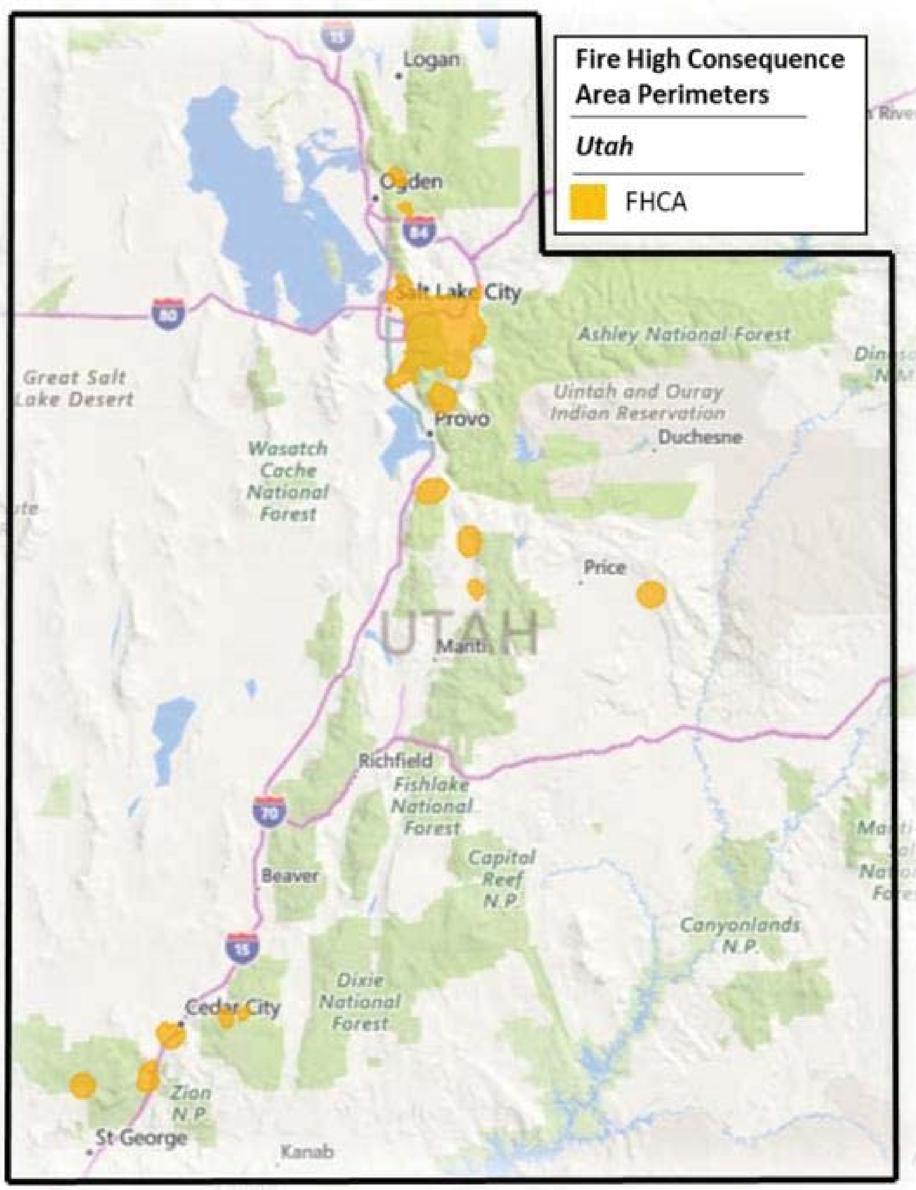

Figure 4. Utah Statewide FHCA Perimeters

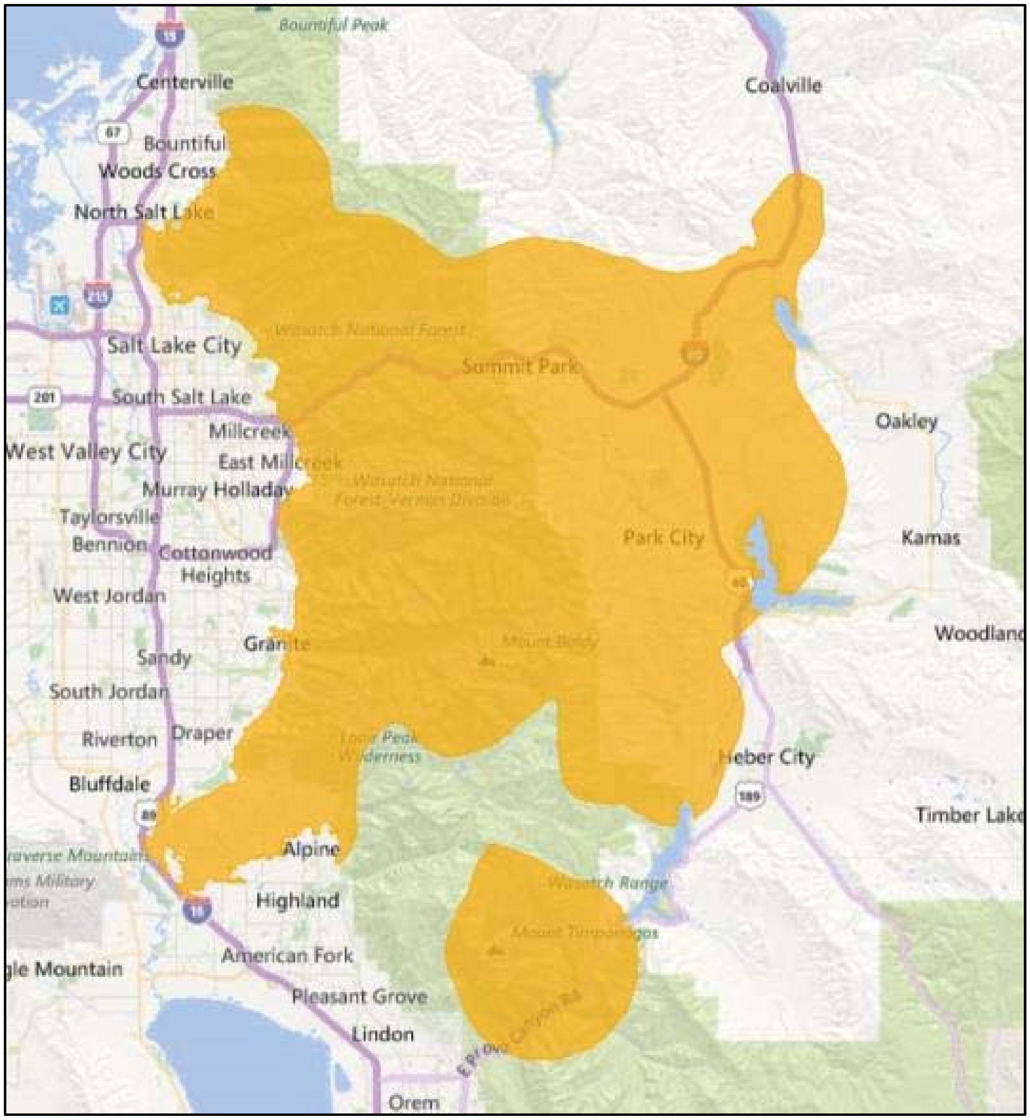

Figure 5. Salt Lake City Metro FHCA Perimeters

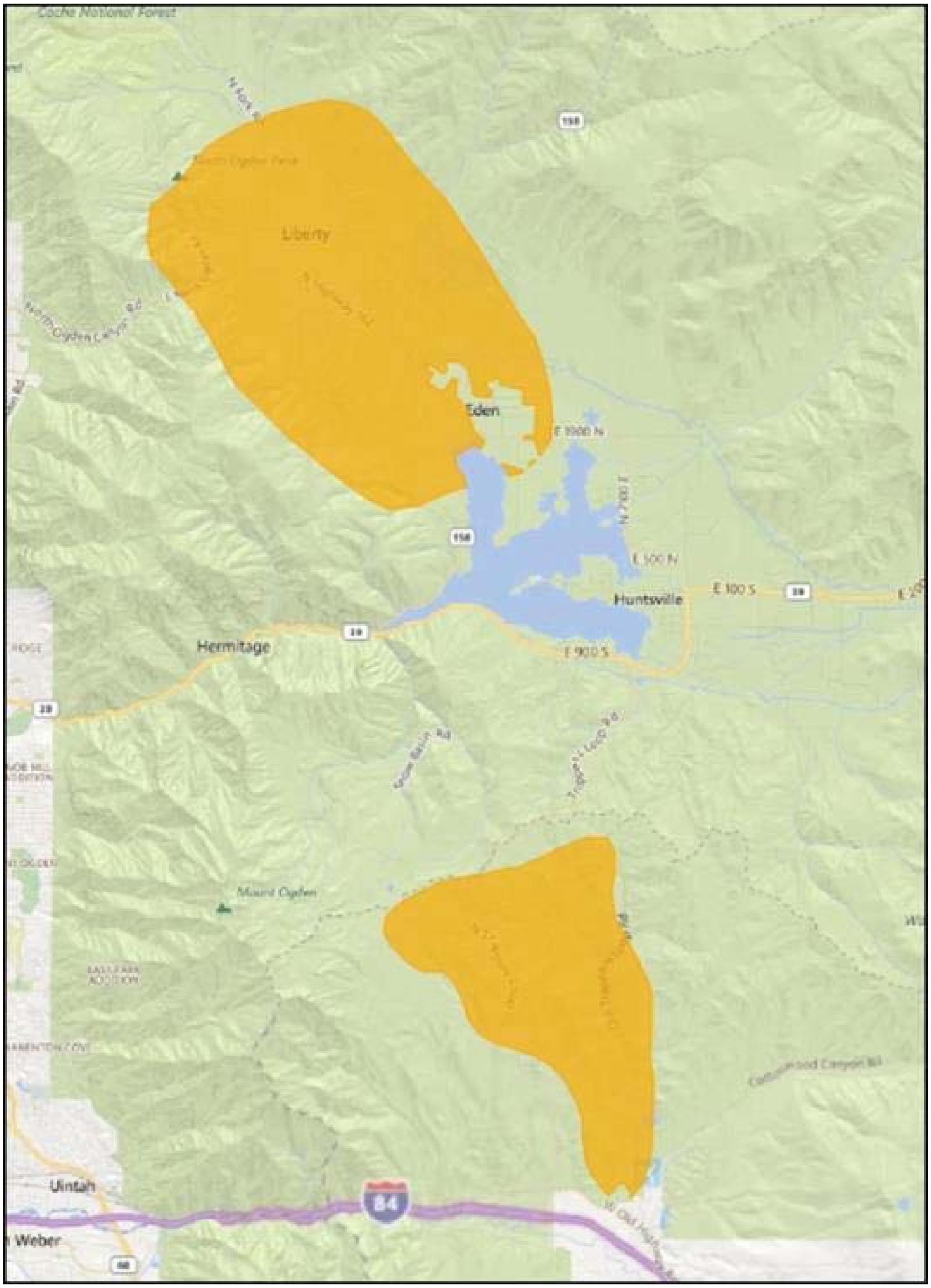

Figure 6. Weber and Morgan Counties FHCA Perimeters

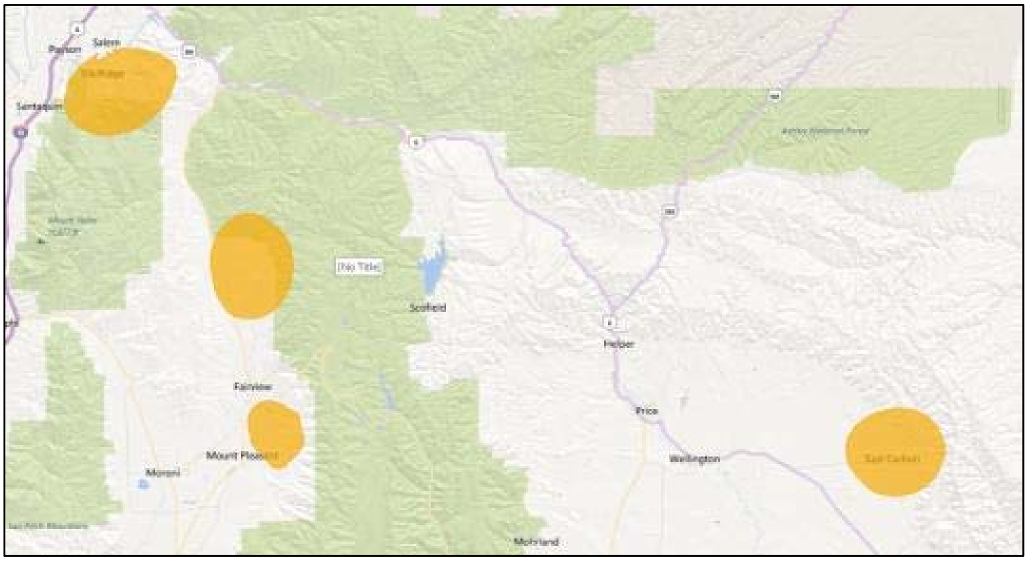

Figure 7. Carbon, Sanpete and Utah Counties FHCA Perimeters

Figure 8. Washington, Iron and Garfield Counties FHCA Perimeters

1.2. Asset Inventory in the FHCA

In Utah, Rocky Mountain Power provides electricity to over 950,000 customers via over 500 substations and 18,000 miles of overhead transmission and distribution lines, across a service territory encompassing nearly 58,900 square miles. The three primary categories of assets subject to wildfire mitigation treatment are described as follows:

Table 3. Primary Asset Categories

Asset Classification	Asset Description
Transmission Line Assets	Include conductor, transmission structures, and switches operating at a higher level voltage (typically, any line operating at or above 46 kV is a transmission line).
Distribution Line Assets	Include overhead conductor, underground cabling, transformers, voltage regulators, capacitors, switches, line protective devices, operating at a lower voltage (again, typically less than 46 kV).
Substation Assets	Include major equipment such as power transformers, voltage regulators, capacitors, reactors, protective devices, relays, open-air structures, switchgear and control houses.

Many wildfire mitigation strategies are focused on assets located in the FHCA. PacifiCorp has 489 miles of distribution line, 210 miles of transmission line and 26 substations located in the FHCA. The following table includes the breakdown of Rocky Mountain Power's Utah assets in the FHCA.

Table 4. Breakdown of Utah Assets in the FHCA

Asset	Total	FHCA	
	Line-Miles	Line-Miles	%
OH Transmission	7077	210	3.0%
46 kV Transmission Lines	2075	79	3.8%
69 kV Transmission Lines	549	17	3.0%
138 kV Transmission Lines	1969	90	4.6%
230 kV Transmission Lines	564	11	2.0%
345 kV Transmission Lines	1918	14	0.7%
OH Distribution	10937	489	4.5%
OH Lines - Miles	18014	699	3.9%
Substations	503	26	5%

1.3. State-Specific Fire History and Causes

To further develop an understanding of wildfire risks in both the state and company service territory, Rocky Mountain Power analyzed Utah fire history and ignition sources from 2008 through 2019, using data from the Utah Division of Forestry, Fire and State Lands (FFSL). Ignition sources, both by number of ignitions in a given category, and by the amount of acres burned by ignitions in a particular category, are shown in the figures below. Whether assessed by the number of ignitions or by the acres burned from a particular cause, lightening was the leading cause of wildfire in Utah over the prior decade. The miscellaneous category next is the next largest category. The miscellaneous category includes ignition causes attributed to power lines, fireworks, firearms and others.

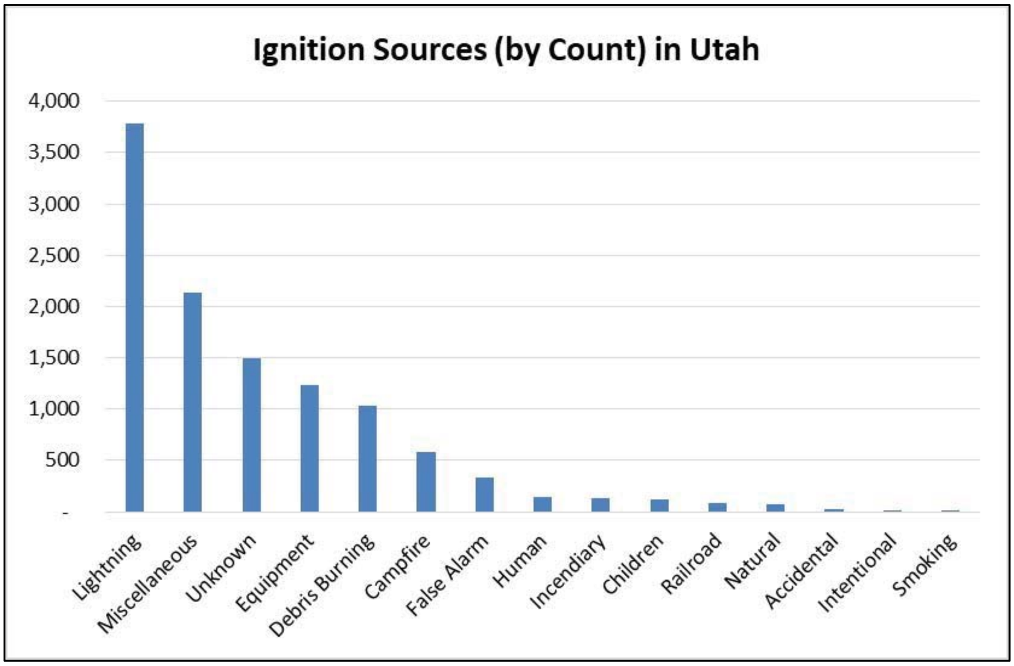

Figure 9. Fire History Ignition Source in Utah

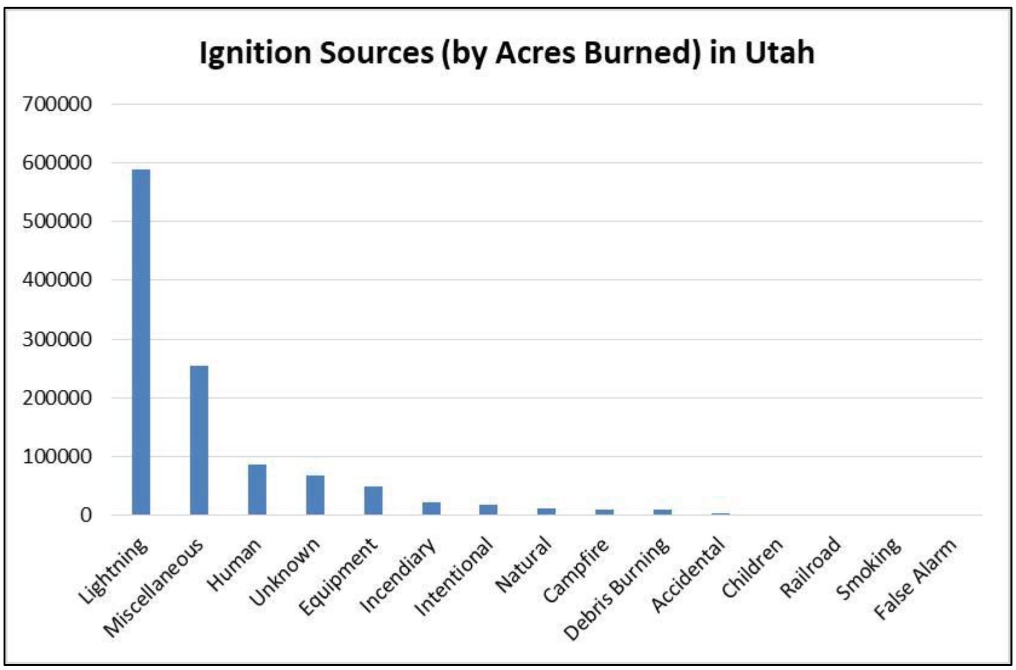

Figure 10. Fire History Total Acres Burned in Utah

The same data, expressed as a percentage of the total in a pie chart format, is shown in the figures below. The equipment category accounts for approximately 19% of the number of ignitions and 23% of ignitions by acres burned.

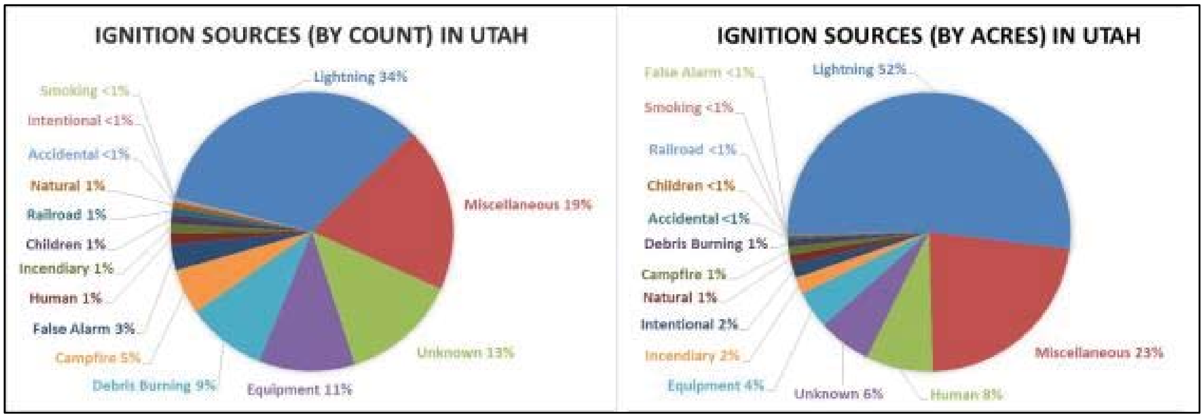

Figure 11. 2008–2019 Fire History Ignition Sources by Count and by Acres for the State of Utah; Percentages of Total Incidents

1.3.1. Determining Historical Fire Season

Rocky Mountain Power plotted the cumulative acres burned against the day of the year for the 12-year period from 2008 to 2019. While it does not mean that a wildfire cannot occur outside of fire season, the following figure supports the general conclusion that June 1 through October 1 is a good representation for when fire risk is elevated for the state as a whole.

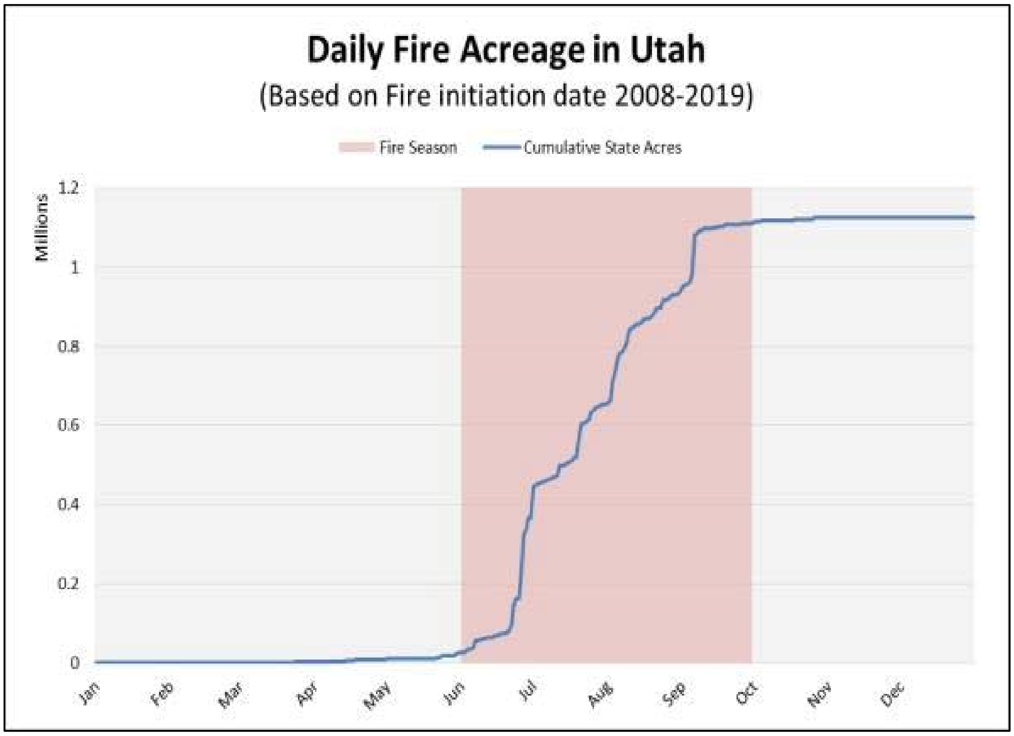

Figure 12. 2008–2019 Cumulative Acres Burned by Day of the Year in Utah.

1.4. Assessment of Electric Utility-Related Fire Ignition Risk

Outage data is the best available data to correlate an identifiable event on the electrical network to the risk of a utility-related wildfire. There is a logical physical relationship, when a fault creates a spark, there is a risk of fire. An outage – which is when a line is unintentionally de-energized – is most often rooted in a fault. Accordingly, the company has closely analyzed the causes and frequency of outages. This analysis is geared to determine which mitigation strategies are best suited to minimize fault events, thereby reducing the risk of fire.

1.4.1. General Outage Categories

Rocky Mountain Power maintains outage records in the normal course of business, as part of Rocky Mountain Power's historical efforts to assess service reliability. These records document the frequency, duration and cause of outages. For purposes of this wildfire risk assessment, the company has created nine categories of outage events, with each category related to a type of wildfire risk. Those categories are listed in the following table:

Table 5. Rocky Mountain Power's Outage Categories

Outage Categories
Contact From Object
Contamination
Equipment Failure
Normal Operation
Other
Unknown
Vandalism/Theft
Contact From Third Party

Using the historical distribution outage data, for the years 2015 to 2019, each individual outage was assigned to one of the outage categories listed above. The results of such categorization are shown in the following tables:

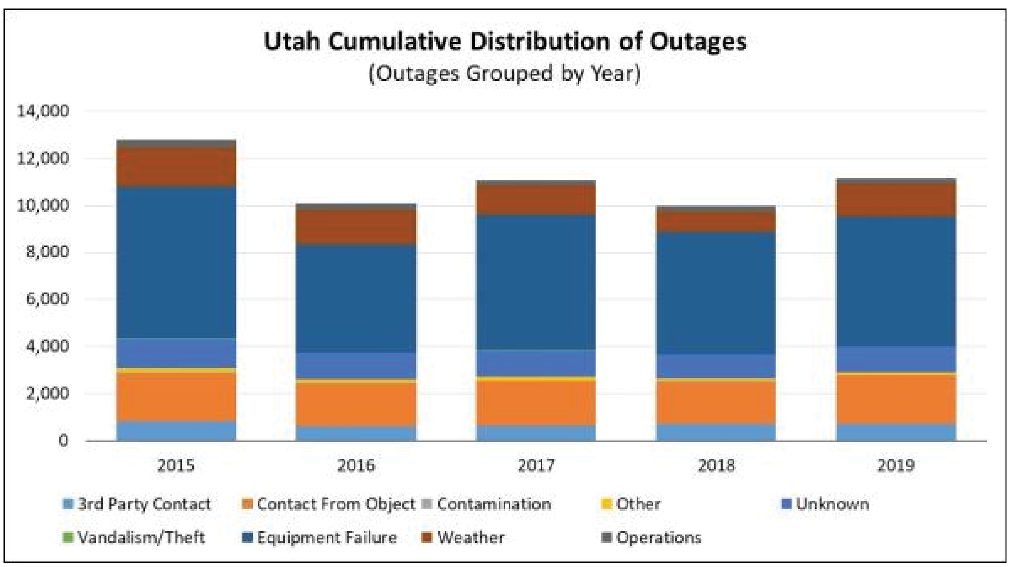

Figure 13. Cumulative Distribution of Outage Category Grouped by Year

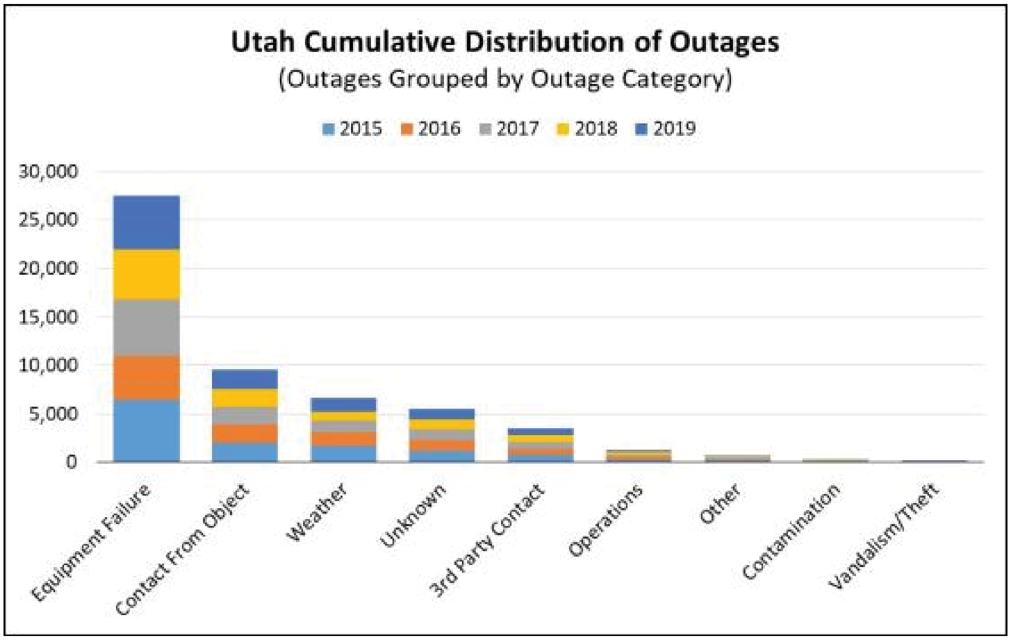

Figure 14. Cumulative Distribution of Outage Category Grouped by Outage Category

1.4.2. Specific Outage Subcategories

To further develop this analysis, the company broke two categories into subcategories. Because of their numerical significance and because of their potential correlation with sparks, the general categories for "Contact From Object" and "Equipment Failure" were subdivided into the following groups:

Table 6. Outage Subcategories for Object Contact and Equipment Failure

Contact From Object	Animal contact
	Other (e.g., balloons)
	Vegetation contact
Equipment Failure	Conductor
	Crossarm
	Cutout
	Insulator
	Lightning arrester
	Other
	Pole
	Sectionalizer
	Splice/clamp/connector
	Switch
	Transformer
	Voltage regulator

Again using the historical outage data, for the same years, each individual outage in the contact from object and equipment failure general categories was assigned to one of the subgroups listed above. The results are shown in the following table:

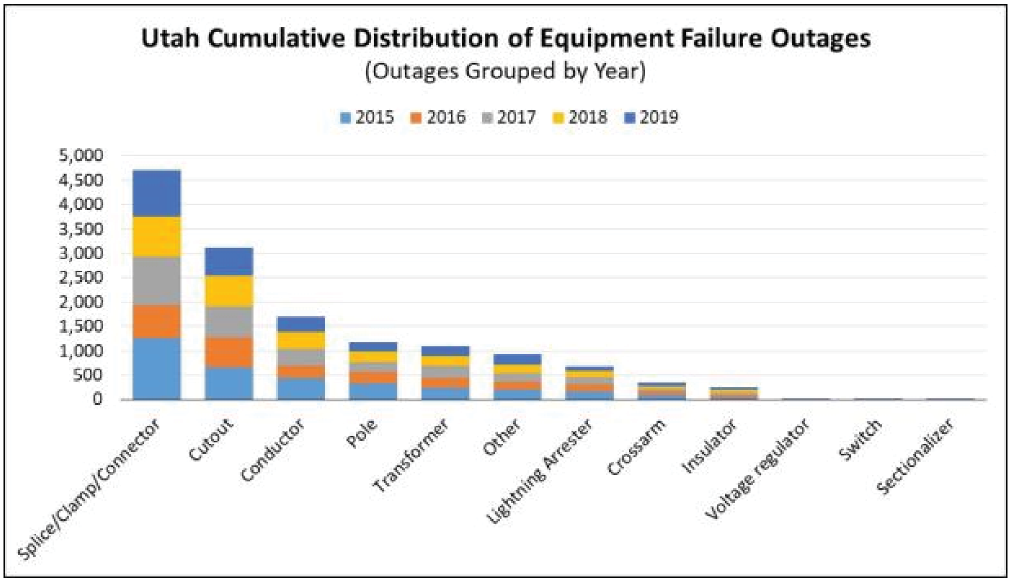

Figure 15. Cumulative Distribution of Equipment Failure Outages

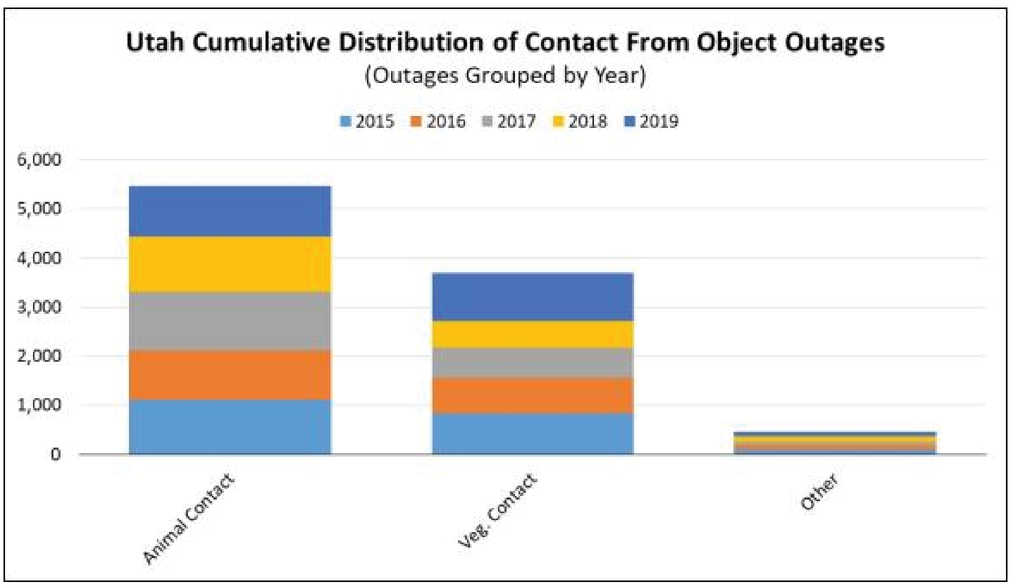

Figure 16. Cumulative Distribution of Contact From Object Outages

1.4.3. Outages During Fire Season

To determine whether any particular outage category occurred more frequently during the fire season, the company also evaluated the outage data from the perspective of time of year. Again using the same outage categories, the analysis counted outages occurring during fire season (June 1 through October 1) versus outages occurring the rest of the year.

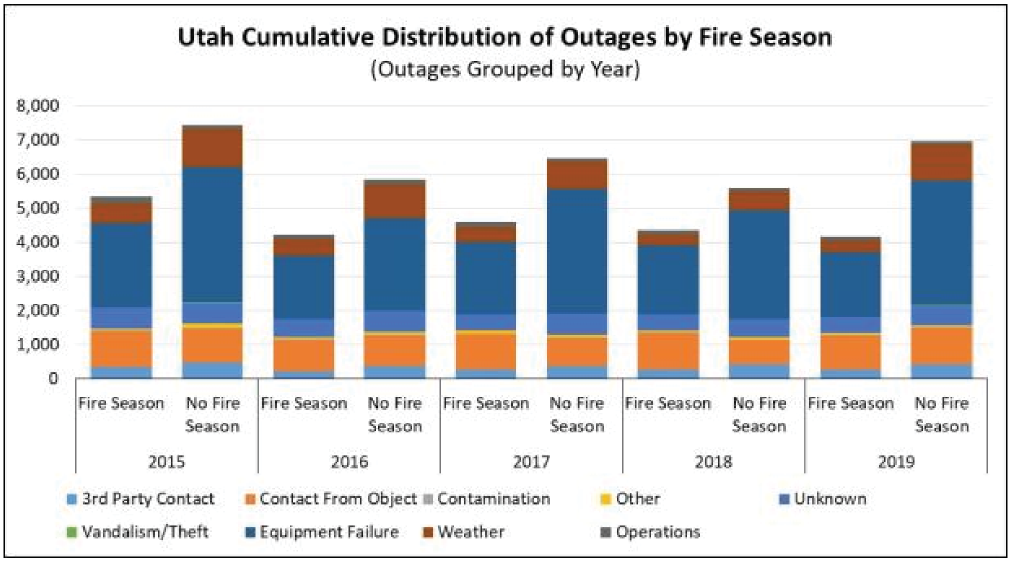

Figure 17. Cumulative Distribution of Outage Category Grouped by Year and Fire Season

This part of the analysis validated that there are no obvious aberrations in the data that would suggest that a particular outage type occurred with overwhelming frequency during fire season. In other words, the two main outage categories, equipment failure and contact from object, remain the largest outage causes, no matter the season. While the other categories remain constant through the year, the equipment failure category experiences the greatest seasonality decreasing during fire season and still remaining the greatest contributor. For this reason – and recognizing the general logic that faults during fire season are the greatest concern for wildfire mitigation – the company focused on the outage totals during fire season. As the data above shows, over the last five years, there has been a downward trend in the number of outages during fire season. One of the goals of this wildland fire protection plan is to continue that trend.

1.4.4. Outages During Fire Season and Within the FHCA

Rocky Mountain Power further analyzed the correlation to outage locations within the FHCA. As discussed above, the greatest risk of catastrophic wildfire is in the FHCA. Consequently, faults in the FHCA reflect the greatest potential ignition risks. Outages in the FHCA correlate to those faults of greatest concern.[9] Consequently, the company identified the number of outages during fire season and in the FHCA. Those numbers are shown in the following table:

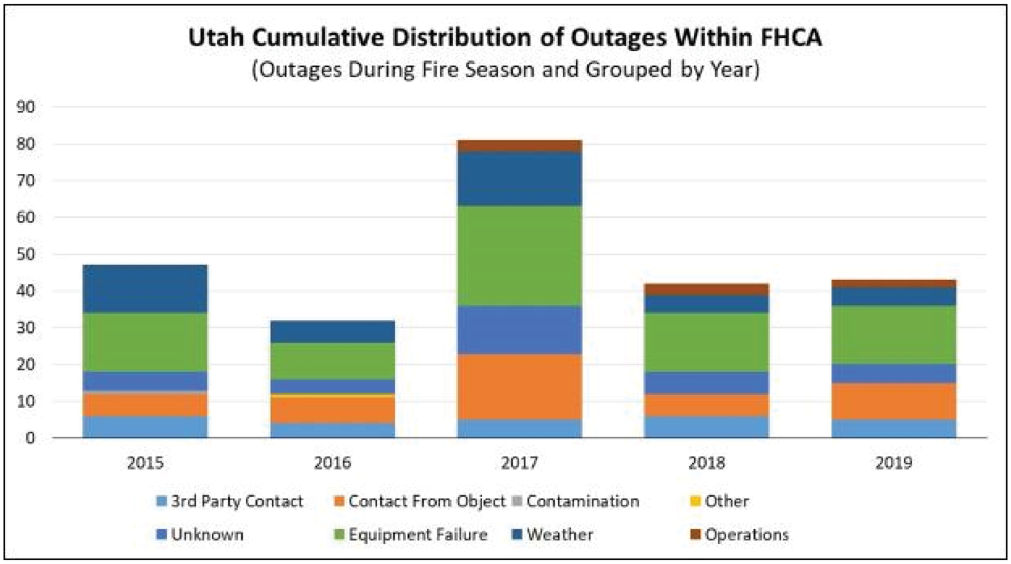

Figure 18. Cumulative Distribution of Outage Category Within FHCA and During Fire Season

This same data is reorganized by general outage categories (and color coded by year), as follows:

[9]There are some constraints on tying outage records to the FHCA. The determination of an FHCA outage is based on the downstream topology within the operating device's Zone of Protection (ZOP). The ZOP of a device includes all lines downstream but not beyond any downstream auto isolating devices. Some portions of the ZOP may touch the FHCA boundary and may not be entirely encompassed within.

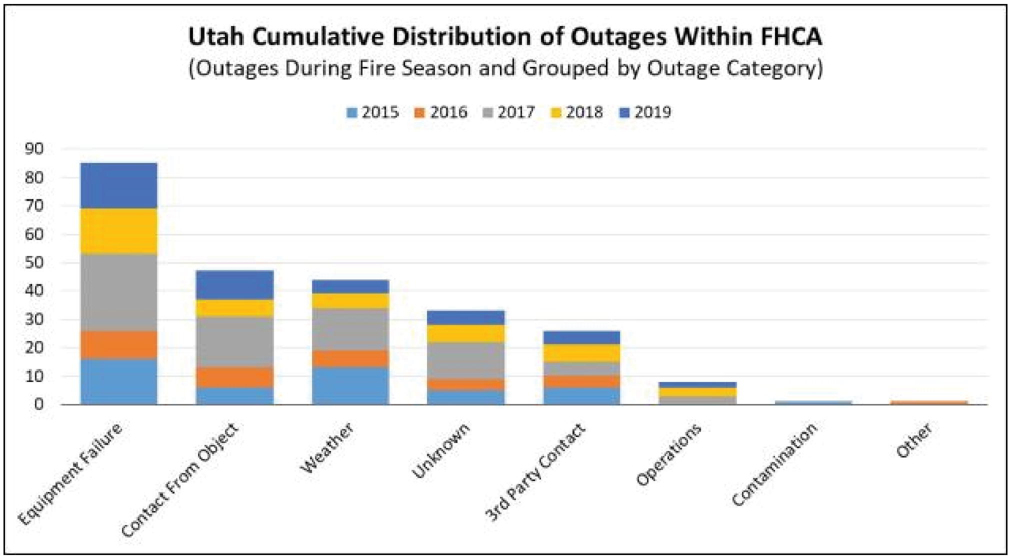

Figure 19. Cumulative Distribution of Outages Within FHCA and During Fire Season by Outage Category

The following figures depict the same data as percentages of the total number of outages during the fire season:

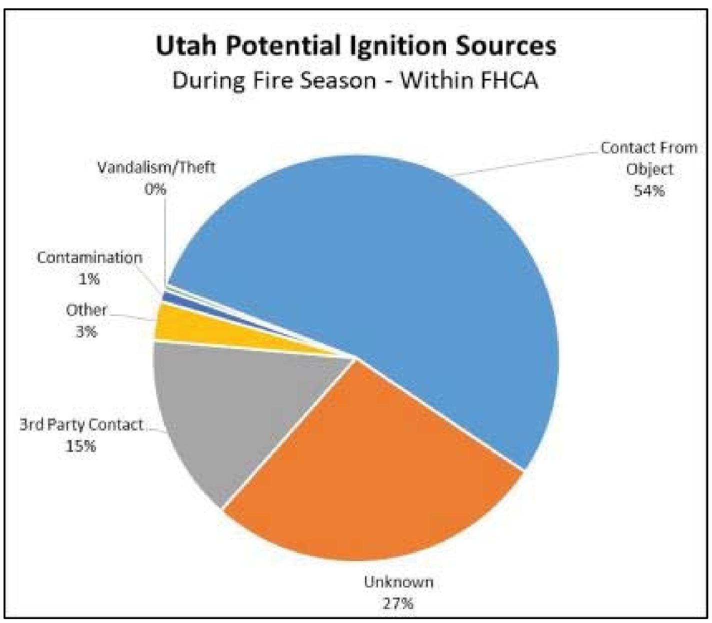

Figure 20. Percentage of Events by Category Within the FHCA, 2015–2019

In sum, this subset of outages, occurring during fire season and in the FHCA, is used as a baseline data set for reference in both designing mitigation strategies aimed at reducing these numbers and measuring performance of the plan on a long-term basis.

1.4.5. Subcategories During Fire Season and Within the FHCA

The complete analysis above affirms the general conclusion that the two categories of greatest concern are contact from objects and equipment failure. As discussed above, Rocky Mountain Power analyzed subcategories within these two leading general categories. Applying that distinction specifically to outages during the fire season and within the FHCA, the results are shown in the figures below:

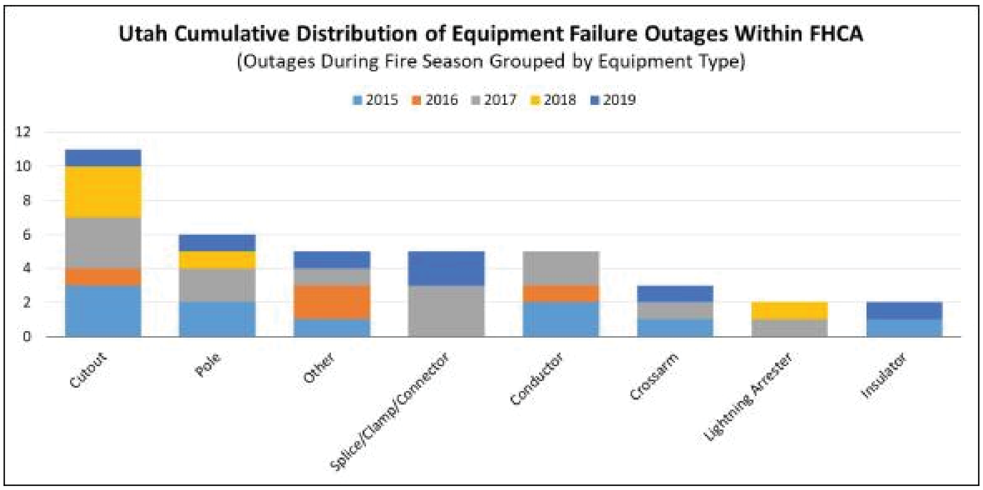

Figure 21. Equipment Subcategories Within the FHCA and During Fire Season

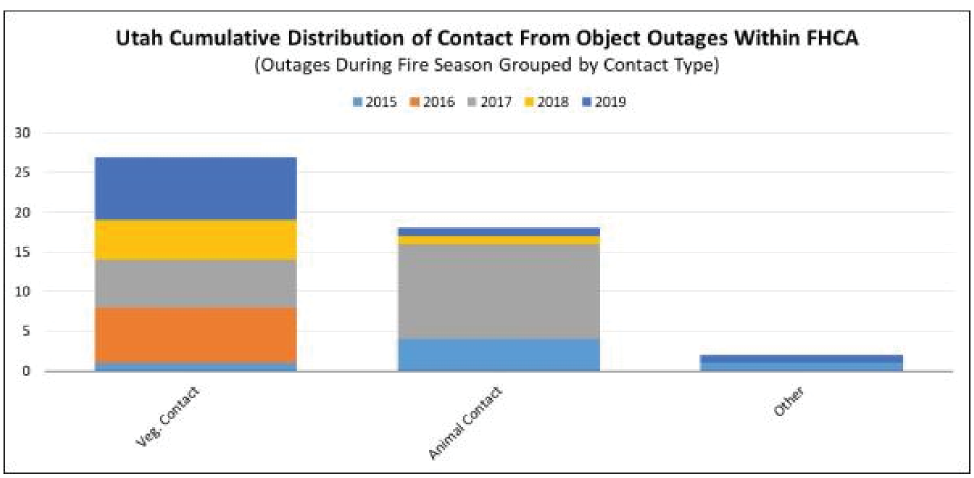

Figure 22. Contact from Object Subcategories Within the FHCA and During Fire Season

1.4.6. Comparison of Outages Outside the FHCA and Within the FHCA

Again using historical data for outages during fire season, the company compared outage rates in the FHCA versus all other areas outside the FHCA. During fire season, equipment failure and contact from object remain the leading outage categories. Together, these categories total 54% of all outages within the FHCA and 68% outside the FHCA. The results of that exercise are shown in the following table and corresponding pie charts for the percent contribution of each outage type in Figure 23.

Table 7. Frequency of Outages by Cause Category

Potential Suspected Initiating Event Type	2015–2019 Total Number of Events During Fire Season in Utah							
	Outside the FHCA				Within the FHCA			
	Rank	Total Events	% Contribution	Events/ Year	Rank	Total Events	% Contribution	Events/ Year
Equipment Failure	1	10,266	46%	2,053	1	85	35%	17
Contact From Object	2	5,045	22%	1,009	2	47	19%	9.4
Unknown	3	2,543	11%	508.6	4	33	13%	6.6
Weather	4	2,079	9%	415.8	3	44	18%	8.8
Third-Party Contact	5	1384	6%	276.8	5	26	11%	5.2
Operations	6	720	3%	144	6	8	3%	1.6
Other	7	293	1%	58.6	7	1	0%	0.2
Contamination	8	90	0%	18	8	1	0%	0.2
Vandalism/Theft	9	37	0%	7.4	9	0	0%	0
Grand Total	**-**	**22,457**	**1**	**4,491**	**-**	**245**	**1**	**49**

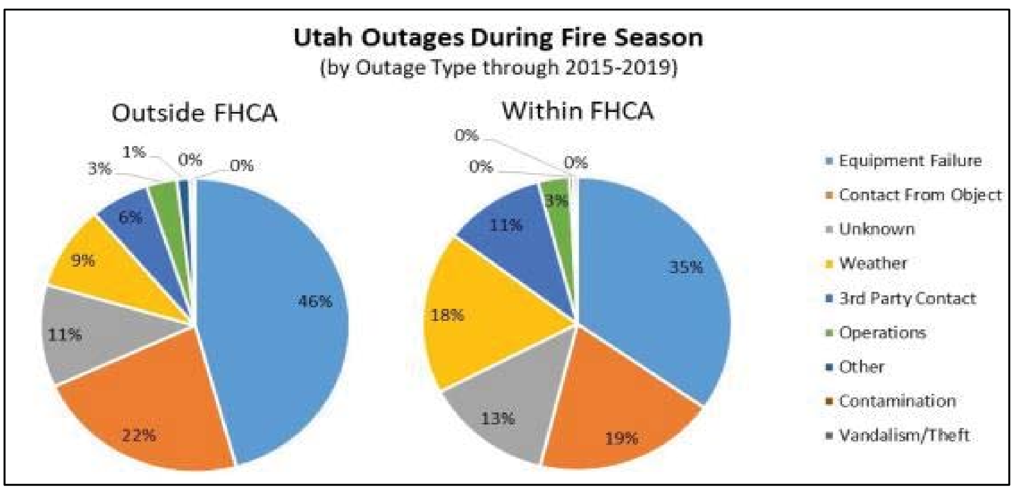

Figure 23. Percent of Outages by Cause Category Occurrence from 2015–2019, Inside and Outside the FHCA

1.5. Risk Assessment Conclusions

While a relatively small percentage of the total number of wildfires are attributable to powerlines, the potential magnitude of any particular wildfire event warrants mitigation efforts. The history of outages on the electrical network, and the faults underlying those outages, reflects the best available data for the wildfire risk assessment. Equipment failure and contact from object presents the greatest utility-related fire risk to Rocky Mountain Power's Utah service territory, together accounting for almost 75% of all outages within the FHCA. Recognizing the reality that a fault is behind those outages, such cause categories also reflect the greatest risk of utility-related wildfires. In contrast, there were relatively few ignition potential events associated with the outage cause categories for third-party contact, contamination and vandalism/theft. As demonstrated by the data, areas inside and outside the FHCA experience the same issues with statistically similar frequency. Equipment failure is a central category of concern. In particular, the number of outages related to fuse operations in the FHCA warrant special focus on that equipment type. Likewise, the data also shows that contact from an object is a greater concern. This data leads to the conclusion that reducing the number of equipment failures and contact-related faults must be the top mitigation priorities. Specific mitigation strategies designed to address these risks are discussed throughout the rest of this plan.

2. Operational Practices

2.1. System Operations

The manner in which an electrical system is operated can mitigate the wildfire risk. Rocky Mountain Power has specific procedures addressing system operations during fire season. These policies are designed to reduce the potential for ignition of a fire from sparks emitted when a line is re-energized despite a disturbance on the line. Recognizing the increasing magnitude of the wildfire risk, the procedures were already significantly revised in June 2018 to incorporate more conservative procedures designed to reduce the potential fault-based ignition on Rocky Mountain Power's electrical network. From a practical perspective, the procedures implicate two primary subject areas: (a) settings for automatic reclosers and (b) line testing after lock-out.

Automatic reclosers are currently deployed on various transmission lines and distribution circuits throughout Rocky Mountain Power's service territory. When a line trips open, an automatic recloser may operate to close the circuit very quickly, so long as the cause of a momentary trip has cleared. The reclosing function allows Rocky Mountain Power to maintain service on a line that had tripped, rather than opening the circuit and de-energizing the line. In general, automatic recloser operation is beneficial because it reduces outages and improves customer reliability. The actual operation of recloser equipment does not directly present wildfire risk, as the recloser equipment itself does not emit sparks or otherwise pose an ignition risk.

The operation of automatic reclosers, however, indirectly implicates some degree of ignition risk. When a fault is detected on the line, a recloser will trip and reclose based on predetermined settings in an attempt to re-energize the line. If the cause of the fault is no longer present when the device recloses, the line will re-energize resulting in limited impact to customers. If the cause of the original fault still remains when the device recloses, however, the original fault may persist and, depending on the circumstances, potentially result in arcing or an emission of sparks. As a result, in some limited circumstances, the second fault scenario could lead to a fire ignition. Accordingly, automatic recloser settings can have a significant impact on wildfire mitigation.

The issue with line-testing on overhead lines is very similar. If a breaker has "locked-out" – meaning that it has opened and no longer conducts electricity – a system operator will sometimes "test" the line. To test the line, the system operator will close the device, thereby allowing the line to be re-energized. If the fault has cleared, then the system will run normally. If the fault has not cleared, the device will lock out again. If the device locks out again, the system operator then knows that additional investigation or work will be required before the line can be successfully re-energized. Because faults are often temporary, line-testing can be an efficient tool to maintain customer reliability. At the same time, line-testing can result in the emission of sparks if a fault has not yet cleared when the line is tested. Accordingly, a "no-test" policy reduces the risk of ignition, and a "no-test" policy is applicable in certain circumstances during fire season.

In general, these system operating procedures are more restrictive when wildfire conditions are more elevated. The specific circumstances in which automatic reclosers are disabled and no-test applies, on both transmission and distribution lines, are fully detailed in the procedures.

2.2. Field Operations

During fire season, Rocky Mountain Power modifies the way it operates in the field to further mitigate wildfire risk. In particular, field operations considers the local weather and geographic conditions that may create an elevated risk of wildfire. These practices are targeted to reduce the potential of direct or indirect causes of ignition during planned work activities, fault response and outage restoration.

Rocky Mountain Power personnel working in the field during fire season mitigate wildfire risk through a variety of tactics. Routine work, such as condition correction and outage response, poses some degree of ignition risk, and, in certain circumstances, crews modify their work practices and equipment to decrease this risk. In the extremely unlikely event that a fire ignition occurs while field crews or other Rocky Mountain Power personnel are working in the field (collectively “field personnel”), such field personnel are equipped with basic tools to extinguish small fires.

Work Restrictions. Rocky Mountain Power field operations is able to mitigate some wildfire risk by managing the way that field work is scheduled and performed. To effectively manage work during fire season, area managers regularly review local fire conditions and weather forecasts provided to them as part of Rocky Mountain Power’s monitoring program – discussed in the situational awareness section below.

During fire season generally, field operations managers are encouraged to defer any nonessential work at locations with dense and dry wildland vegetation, especially during periods where the National Weather Service has issued a *Red Flag Warning* and/or the fire agency having jurisdiction issues a *Fire Restriction* or *Closure Order*. If essential work needs to be performed in the FHCA and other areas with appreciable wildland vegetation, certain restrictions may apply, including:

- **Hot Work Restrictions.** Field operations managers are encouraged to evaluate whether work should be performed during a planned interruption, rather than while a line is energized.
- **Time of Day Restrictions.** Field operations managers are encouraged to consider using alternate work hours to accommodate evening and night work, when there may be less risk of ignition.
- **Wind Restrictions.** Field personnel are encouraged to defer work, if feasible, when there are windy conditions at a particular work site.
- **Driving Restrictions.** Field personnel are encouraged to keep vehicles on designated roads whenever operationally feasible.

Worksite Preparation. If wildland vegetation posing an ignition risk is prevalent at a worksite, and the work to be performed involves the potential emission of sparks from electrical equipment, field personnel working during fire season are encouraged to employ best practices and remove vegetation at the work site where allowed in accordance with land management/agency permit requirements, especially when there is dry or tall wildland grass. In addition to clearing work, the water truck resources, discussed below, are strategically assigned to sometimes accompany field personnel working in a wildland area during fire season, especially in the FHCA. Depending on local conditions, dry vegetation in the immediate vicinity may be sprayed with water before work as a preventative measure.

Additional Labor Resources. Some wildfire mitigation activities require the time of field personnel, including in two key areas: (a) supporting system operations in administering the procedures discussed above and (b) responding to outages during fire season. The increased operations cost associated with these activities will be tracked and included in the annual report filed in conjunction with this plan.

Under normal operating procedures, system operators and field personnel work together on a daily basis to manage the electrical network. In many situations, system operators depend on field personnel to gather information and assess local conditions. As discussed above, there are system operations procedures during wildfire season for disabling automatic recloser functions and limiting line-testing. Consequently, system operators need field personnel to gather information and assess local conditions during fire season more frequently than would otherwise be required under normal operating procedures. The requests from system operators may be varied, ranging from a simple phone call to confirm that it is raining in a particular area, to a much more time-intensive request, such as a full line patrol on a circuit.

Field personnel may also spend some additional time when responding to an outage during fire season. After a fault results in an outage, all or part of a circuit might remain de-energized while restoration work is performed, depending on the design, loading conditions and sectionalizing capability of the circuit experiencing the outage. Occasionally, additional foreign objects, such as tree limbs or other debris, can come into contact with the de-energized line and remain undetected throughout the duration of restoration efforts. Under normal operating procedures and consistent with prudent utility practices, a line is typically re-energized as soon as restoration work is complete. Consequently, a re-energized line could immediately experience a new fault if some contact between the line and foreign object had occurred while restoration work was being performed. The new fault would, of course, present additional wildfire risk, because of the potential of a spark being emitted as a result of a fault occurring when the line was re-energized. To mitigate this risk, field operations may perform, during fire season and particularly in the FHCA, depending on current conditions at the work site and the duration of the restoration work, some amount of line patrol on certain de-energized sections of the circuit. Depending on the circumstances, this extra patrol might be done just before or just after re-energizing the line. Typically, this type of line patrol does not involve a close inspection of any particular facility; instead, it is a quick visual assessment specifically targeted to identify obvious foreign objects that may have fallen into the line during restoration work.

Basic Personal Suppression Equipment. Personal safety is the first priority, and Rocky Mountain Power field personnel are encouraged to evacuate and call 911 if necessary. Field personnel working in the FHCA maintain the capability to extinguish a small fire that ignited while they are working in the field. Field personnel should attempt suppression only if the fire is small enough so that one person can effectively suppress the fire while maintaining their personal safety. All field personnel working in the FHCA during fire season will have basic suppression equipment available onsite, because field utility trucks typically carry the following equipment: (1) fire extinguisher; (2) shovel; (3) Pulaski; (4) water container; and (5) dust mask. The water container should hold at least five gallons and may be a pressurized container or a backpack with a manual pump.

Mobile Generators. Rocky Mountain Power has a small number of mobile generators to assist with emergency response efforts. In short, when power on the electrical network is lost, either proactively or as the result of wildfire damage, a mobile generator unit can be dispatched to provide power. The generator is transported via tractor trailer to a specific location based on real-time circumstances. For example, a mobile generator may be dispatched by the Emergency Operations Center to mitigate the impact of a proactive de-energization, as discussed in greater detail in the Public Safety Power Shutoff section below. There are constraints in connecting the generator, and each deployment is examined on a case-by-case basis. As part of this wildland fire protection plan, Rocky Mountain Power plans to purchase three 425 kW mobile generators.

Water Truck Resources. Rocky Mountain Power has water trucks that field operations use to mitigate against wildfire risk. These resources are not dispatched to reported fires (i.e., like a fire truck). Instead, Rocky Mountain Power resources are strategically assigned to accompany field personnel. If conditions are warranted the Emergency Operations Center or incident commander can strategically assign water truck resources to accompany field personnel. For example, if it is necessary to perform work in the FHCA during a period in which there is a *Red Flag Warning*, Rocky Mountain Power field operations may schedule a water truck to join field personnel working in the field. As discussed above, the water truck can be used to help prep the site for work. By watering down dry vegetation in the work area, any chance of an ignition can be minimized. Field operations currently has eight water trucks for use in such applications. In addition, the company plans to purchase two water trucks and one trailer. The locations and types of existing water truck resources owned by Rocky Mountain Power are listed in the following table.

Table 8. Water Truck Resources

Mobile Equipment	Location	Contact
1 ton – 4×4 Water Truck (72197)	Salt Lake City, UT	Operations manager
1 ton – 4×4 Water / Line Patrol Truck (72730)	American Fork, UT	Operations manager
1.5 ton – 4×4 Water Truck (74631)	American Fork, UT	Operations manager
1 ton – 4×4 Water Truck (76352)	American Fork, UT	Operations manager
1 ton – 4×4 Water Truck	American Fork, UT	Operations manager
1 ton – 4×4 Water Truck	Park City, UT	Operations manager
1 ton – 4×4 Water Truck	Cedar City, UT	Operations manager
1 ton – 4×4 Water Truck	Salt Lake City, UT	Operations manager

3. Inspection and Correction

Inspection and correction programs are the cornerstone of a resilient system. These programs are tailored to identify conditions that could result in premature failure or potential fault scenarios, including situations in which the infrastructure may no longer be able to operate per code or engineered design, or may become susceptible to external factors, such as weather conditions.

Rocky Mountain Power performs inspections on a routine basis as dictated by both state-specific regulatory requirements and Rocky Mountain Power-specific policies. When an inspection is performed on a Rocky Mountain Power asset, inspectors use a predetermined list of condition codes (defined below) and priority levels (defined below) to describe any noteworthy observations or potential noncompliance discovered during the inspection. Once recorded, Rocky Mountain Power uses condition codes to establish the scope of and timeline for corrective action to make sure that the asset is in conformance with National Electric Safety Code (NESC) requirements, state-specific code requirements and/or Rocky Mountain Power specific policies. This process is designed to correct conditions while reducing impact to normal operations.

Key terms associated with Rocky Mountain Power's Inspections & Corrections Program are defined as follows:

- **Detailed Inspection.** A careful visual inspection accomplished by visiting each structure, as well as inspecting spans between structures, which is intended to identify potential nonconformance with the NESC or other applicable state requirements, nonconformance with Rocky Mountain Power construction standards, infringement by other utilities or individuals, defects, potential safety hazards, and deterioration of the facilities that need to be corrected to maintain reliable and safe service.

- **Pole Test & Treat.** An inspection of wood poles to identify decay, wear or damage, which may include pole-sounding, inspection hole drilling, and excavation tests to assess the pole condition and identify the need for any repair, or replacement and apply remedial treatment according to policy.
- **Visual Assurance Inspection.** A brief visual inspection performed by viewing each facility from a vantage point allowing reasonable viewing access, which is intended to identify damage or defects to the transmission and distribution system, or other potential hazards or right-of-way-encroachments that may endanger the public or adversely affect the integrity of the electric system, including items that could potentially cause a spark.
- **Condition.** The state of something with regard to appearance, quality, or working order that can sometimes be used to identify potential impact to normal system operation or clearance, which is typically identified by an inspection.
- **Condition Codes.** Predetermined list of codes for use by inspectors to efficiently capture and communicate observations and inform the scope of and timeline for potential corrective action.
- **Correction.** Scope of work required to remove a condition within a specified timeframe.
- **Priority Level.** The level of risk assigned to the condition observed, as follows:
  - Imminent – imminent risk to safety or reliability
  - Priority A – risk of high potential impact to safety or reliability
  - Priority B – low to moderate risk to safety, reliability or worker safety
  - Priority D – issues that are not NESC conformance issues that are recorded for informational purposes
  - Priority G – grandfathered conditions that conformed to NESC requirements that were in place when construction took place but do not conform to more current code revisions

3.1. Current Inspection and Correction Programs

Rocky Mountain Power’s asset inspection program involves three primary types of inspections: (1) visual assurance inspection; (2) detailed inspection, and (3) pole test & treat. Inspection cycles, which dictate the frequency of inspections, are set by Rocky Mountain Power asset management. In general, visual assurance Inspections are conducted more frequently, to quickly identify any obvious damage or defects that could affect safety or reliability, and detailed inspections are performed less frequently, with a more detailed scope of work. The frequency of pole test & treat is based on the age of wood poles, and such inspections are typically scheduled in conjunction with certain detailed inspections. The inspector conducting the inspection will assign a condition code to any conditions found and the associated priority level in Rocky Mountain Power's facility point inspection (FPI) system. Corrections are then scheduled and completed within the correction timeframes established by Rocky Mountain Power asset management, as discussed below. While the same condition codes are used throughout Rocky Mountain Power's service territory, the timeframe for corrective action is different in different state jurisdictions. In all cases, the timeline for corrections takes into account the priority level of any identified condition. A priority A condition is addressed on a much shorter timeframe than a priority B condition.

3.2. Proposed Inspection and Correction Programs

The existing inspection and correction programs are effective at maintaining regulatory compliance and managing routine operational risk. They also mitigate wildfire risk by identifying and correcting conditions that, if uncorrected, could ignite a fire. Nonetheless, recognizing the growing risk of wildfire, asset management proposes to supplement existing programs to mitigate the growing wildfire-specific operational risks and create greater resiliency against wildfires. There are three primary elements to this proposal: (1) creating a fire risk condition classification; (2) increasing inspection frequencies in Fire High Consequence Areas (FHCA); and (3) narrowing correction timeframes for fire risk conditions.

Fire Risk Conditions. Rocky Mountain Power now designates certain conditions as "fire risk conditions." Each condition is still assigned a condition code (e.g., CONDFRAY for a damaged or frayed primary conductor) – but certain condition codes are categorically designated as a fire risk condition. Accordingly, if a condition is designated under a particular condition code associated as a fire risk, the condition will also be designated as a fire risk condition. To this end, a review was performed on all existing condition codes to determine whether the condition code could have any correlation with fire ignition. Condition codes reflecting an appreciable risk of fire ignition were designated as fire risk conditions. For example, if a damaged or frayed primary conductor was observed during an inspection, the inspector would record condition code CONDFRAY, which is designated as a fire risk condition because the condition could eventually result in an ignition under certain circumstances. In contrast, the observation of a missing or broken guy marker would result in the condition code GUYMARK, which is not designated as a fire risk condition.

Inspection Frequency. Asset management also plans to increase the frequency of all three inspections types for assets located in the FHCA. Consistent with industry best practices, inspections are Rocky Mountain Power's preferred mechanism to identify conditions. An increase in the frequency of inspections will result in more timely identification of potential fire risk conditions. Inspection frequencies for Utah asset types are summarized in the following table:

Table 9. Current and Proposed Inspection Frequency in the FHCA

Inspection Type	Current Inspection Frequency in years)	Proposed Inspection Frequency (in years)
OH Distribution (Less than 46 kV)		
Visual	2	1
Detailed	20	5
Pole Test & Treat	n/a	10
OH Local Transmission (more than 46 kV and Less than 200 kV)		
Visual	2	1
Detailed	10	5
Pole Test & Treat	10	10
OH Main Grid (More than 200 kV)		
Visual	1	1
Detailed	2	2
Pole Test & Treat	10	10

Correction Timeframe. Rocky Mountain Power will further mitigate wildfire risk by reducing the time allowed for correction of fire risk conditions in the FHCA. As expressed above, certain types of conditions have been identified as having characteristics associated with a higher risk of wildfire potential. Accordingly, Rocky Mountain Power is prioritizing those conditions for correction. Because of the risk of catastrophic wildfire in the FHCA, Rocky Mountain proposes an aggressive correction schedule for fire risk conditions in the FHCA, requiring that priority A conditions be corrected on a 60-day average and that B fire risk conditions be corrected within 12 months. Correction timeframes for fire risk conditions in the FHCA are summarized in the following table:

Table 10. Current and Proposed Correction Timeframes for Fire Risk Conditions in the FHCA

Condition	Current Correction Timeframes	Proposed Correction Timeframes
A – imminent	Immediate	Immediate
A – fire risk and in the FHCA	120 days on average	60 days on average
B – fire risk and in the FHCA	not specified	12 months

4. Vegetation Management

Good vegetation management is generally recognized as a significant strategy in any wildland fire protection plan. Contact between vegetation and a power line can be a source of fire ignition. Thus, reducing vegetation contacts reduces the potential of an ignition originating from electrical facilities. While it would be virtually impossible to eliminate vegetation contacts completely, at least without radically altering the landscape near power lines, a primary objective of Rocky Mountain Power's existing vegetation management program is to minimize contact between vegetation and power lines. This objective is in alignment with core wildland fire protection efforts, and continuing dedication to administering existing programs is a solid foundation for Rocky Mountain Power's wildland fire protection efforts. To supplement the existing program, Rocky Mountain Power vegetation management is implementing additional wildland fire protection strategies in Fire High Consequence Areas (FHCA).

4.1. Regular Vegetation Management Program

Rocky Mountain Power's vegetation management program is described in detail in Rocky Mountain Power's Transmission & Distribution Vegetation Management Program Standard Operating Procedures ("Standard Operating Procedures"). The focus of Rocky Mountain Power's vegetation management efforts is different for distribution lines and transmission lines. In both cases, typical work functions include pruning and tree removals. Rocky Mountain Power prunes trees to maintain a safe distance between tree limbs and power lines. Rocky Mountain Power also removes trees that pose an elevated risk of falling into a power line. But Rocky Mountain Power uses significantly more restrictive clearance protocols under transmission lines and typically has wider rights-of-way to remove vegetation. Similar to other utilities, Rocky Mountain Power contracts with vegetation management service providers to perform the pruning and tree removal work for both transmission and distribution lines.

Distribution – Cycle Maintenance. Vegetation management on distribution circuits is completed on a cyclical basis. In Rocky Mountain Power's Utah service territory, distribution work is done on a three-year cycle. All vegetation on a given circuit scheduled for work is pruned to comply with defined minimum clearance specifications. Because some trees grow faster than others, minimum clearance specifications vary depending on the type of tree being pruned. For example, faster growing trees need a greater minimum clearance to maintain clearance throughout cycle.

Rocky Mountain Power also integrates spatial concepts to distinguish between side clearances, under clearances and overhang clearances. Recognizing that certain trees grow vertically faster than other trees, it is appropriate to use an increased clearance when moderate- or fast-growing trees are under a conductor. Increasing overhang clearances also reduces the potential for any contacts due to falling overhang.

The minimum clearance specifications are designed so that clearance with primary lines will be maintained throughout the cycle. The specific lengths for the minimum clearance specifications are set forth in Section 5.2 of the Standard Operating Procedures as follows:

Table 11. Distribution Minimum Vegetation Clearance Specifications for a Three-Year Cycle

Three-Year Cycle			
	Slow Growing (< 1 ft./yr.)	**Moderate Growing (1-3 ft./yr.)**	**Fast Growing (>3 ft./yr.)**
Side Clearance	8 ft.	10 ft.	12 ft.
Under Clearance	10 ft.	12 ft.	14 ft.
Overhang Clearance	12 ft.	12 ft.	12 ft.

When a tree is pruned, natural target pruning techniques are used to protect the health of a tree. Natural targets are the final pruning cut location at a strong point in a tree's disease defense system, which are branch collars and proper laterals. Pruning at natural targets protects the joining trunk or limb.[10] Consequently, an actual cut is typically beyond the minimum clearance distance listed in the table above. In all cases, however, the cut is at least to the minimum clearance distance.

Rocky Mountain Power also removes all high-risk trees as part of distribution cycle work, to minimize vegetation contact. High-risk trees are defined in the Standard Operating Procedures as "dead, dying, diseased, deformed, or unstable trees that have a high probability of falling and contacting a substation, distribution or transmission conductors, structure, guys or other Rocky Mountain Power electric facility."[11] Inspections are performed on distribution lines in advance of distribution cycle maintenance work, to identify which trees will be worked in the cycle, including high-risk trees subject to removal. To identify hazard trees, Rocky Mountain Power uses the practices set forth in ANSI A300 (Part 9); Smiley, Matheny and Lilly (2011), Best Management Practices: Tree Risk Assessment, International Society of Arboriculture; and Cal Fire Power Line Fire Prevention Field Guide §§ 12-19. In summary, Rocky Mountain Power uses an initial Level 1 assessment, as defined in ANSI A300 (Part 9), with particular attention to the prevailing winds and trees on any uphill slope. Suspect trees are subjected to a Level 2 assessment, as outlined in ANSI A300 (Part 9), to further assess their condition. After the work is completed, Rocky Mountain Power conducts post-work inspections as part of an audit and quality review process.

Distribution cycle work also includes work designed to reduce future work volumes. In particular, volunteer saplings, small trees that were not intentionally planted, are typically removed if they could eventually grow into a power line. From a long-term perspective, this type of inventory reduction helps mitigate wildfire risk by eliminating a potential vegetation contact long before it could ever occur.

[10]This technique is drawn from ISA Best Management Practices: Tree Pruning (Gilman and Lilly 2002) and A300 (ANSI 2008). (See also Miller, Randall H., 1998. Why Utilities "V-Out" Trees. Arborist News. 7(2):9-16.)
[11]See Table 2 of FAC-003-04, available at
https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf

Transmission Line Vegetation Management. Vegetation management on transmission lines is also focused on maintaining clearances, but the clearance distances are greater. Because of the nature of transmission lines, wider rights-of-way generally allow Rocky Mountain Power to maintain clearances well in excess of the required minimum clearances set forth in the "Minimum Vegetation Clearance Distance" (MVCD[12]). Accordingly, rather than scheduling vegetation management work for transmission lines on a fixed cycle timeframe, such work is scheduled on an as-needed basis, depending on the results of regular inspections and specific local conditions. To determine whether work is needed, an "Action Threshold" is applied, meaning that work is done if vegetation has grown within the action threshold distance. When work is completed, vegetation is cleared to the minimum clearance as specified in this table:

Table 12. Transmission Minimum Vegetation Clearance by Transmission Line Voltage

Transmission Clearance Requirements (in feet)								
	500 kV	**345 kV**	**230 kV**	**161 kV**	**138 kV**	**115 kV**	**69 kV**	**45 kV**
Minimum Vegetation Clearance Distance (MVCD)	8.5	5.3	5.0	3.4	2.9	2.4	1.4	N/A
Action Thresholds	18.5	15.5	15.0	13.5	13.0	12.5	10.5	5
Minimum Clearances Following Work	50	40	30	30	30	30	25	20

Taking advantage of greater legal rights to manage the vegetation in the right-of-way for transmission lines, Rocky Mountain Power employs "Integrated Vegetation Management" (IVM) practices to prevent vegetation growth from ever violating clearances. Rather than depending on pruning in regular work cycles, IVM seeks to prevent clearance issues from ever emerging, by managing the species of trees and other vegetation growing in the right-of-way. Under such an approach, Rocky Mountain Power removes tree species that could potentially threaten clearance requirements, while encouraging cover vegetation, which would never implicate clearance issues.

Line patrolmen inspect most transmission lines annually and notify the vegetation management department of any vegetation conditions. Regional foresters in the vegetation management department also conduct regular inspections of vegetation near transmission lines, including annual inspections of vegetation on all main grid transmission lines. Vegetation work is scheduled dependent on a number of local factors, which is consistent with industry standards and best management practices. Vegetation work on local transmission overbuild is completed on the distribution cycle schedule and inspected accordingly.

[12]See Table 2 of FAC-003-04, available at
https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-003-4.pdf

All of these strategies and techniques are described in much greater detail in the Standard Operating Procedures. The current form of the Standard Operating Procedures was first published in 2008, and periodic updates to content have been made. The most current version is Revision 07, dated August 19, 2019.

4.2. New Wildland Fire Protection Strategies

After identifying lines in the FHCA, Rocky Mountain Power implemented three new elements to its long-term vegetation management program for the purpose of further mitigating wildfire risk in those areas. First, Rocky Mountain Power vegetation management is now doing annual vegetation inspections on all lines in the FHCA, with correction work also completed based on those inspection results. Second, vegetation management increased the minimum clearance distances applicable to distribution cycle work completed in the FHCA. Third, vegetation management now completes annual pole clearing on subject equipment poles located in the FHCA.

Annual Vegetation Inspection. With a program that started in 2019, Rocky Mountain Power vegetation management now conducts annual vegetation inspections for all lines located in the FHCA. Although conducting annual vegetation inspections is above and beyond traditional industry standards, Rocky Mountain Power vegetation management believes that this tool is the most effective strategy to identify high-risk trees at the earliest stage possible. This strategy facilitates removal of high-risk trees before such trees could ever fall into a line and cause a wildfire.

Each year, before the height of fire season, a vegetation inspection will be completed on all lines in the FHCA by a qualified arborist. Consistent with existing procedures, a Level 1 assessment will be conducted to identify any trees that may have become high-risk trees over the course of the prior year; suspect trees are subjected to a Level 2 assessment, as outlined in ANSI A300 (Part 9). In addition, as an additional supplement to normal distribution cycle work, the inspector will identify for pruning or removal vegetation that is likely to violate minimum clearance distances before the next annual inspection.

In conjunction with such annual inspections, vegetation management shall annually complete correction work based on the inspection results, including the prompt removal of all high-risk trees identified during the annual vegetation

Extended Clearances. Rocky Mountain Power has also adopted increased minimum clearance specifications for any distribution cycle work in the FHCA. The new minimum clearance specifications require pruning to at least 12 feet, in all directions and for all types of trees. As discussed above, minimum clearance specifications dictate the distance achieved after pruning is completed. By increasing the minimum distance required at the time pruning is done, Rocky Mountain Power further minimizes the potential of vegetation contacting a power line at any time. The proposed minimum clearance specifications for the FHCA are as follows:

Table 13. Distribution Minimum Vegetation Clearance Specifications in the FHCA

	FHCA		
	Slow Growing (< 1 ft./yr.)	**Moderate Growing (1-3 ft./yr.)**	**Fast Growing (>3 ft./yr.)**
Side Clearance	12 ft.	12 ft.	14 ft.
Under Clearance	12 ft.	14 ft.	16 ft.
Overhang Clearance	12 ft.	14 ft.	14 ft.

By increasing distances to at least 12 feet, Rocky Mountain Power vegetation management will meet or exceed industry standards and best practices. While certain fast-growing trees can sometimes exceed expected annual growth, these minimum clearance specifications are designed with the expectation that such clearances achieved at the time of work will result in vegetation likely never impinging a 4-foot clearance at any time before the next work cycle.

Pole Clearing. Rocky Mountain Power vegetation management performs pole clearing on subject equipment poles located in the FHCA. Pole clearing involves removing all vegetation within a 10-foot radius cylinder of clear space around a subject pole and applying herbicides and soil sterilants to prevent any vegetation regrowth (unless prohibited by law or the property owner). This strategy is distinct from the clearance and removal activities discussed above because it is not designed to prevent contact between vegetation and a power line. Instead, pole clearing is designed to reduce the risk of fire ignition if sparks are emitted from electrical equipment. Pole clearing will be performed on wildland vegetation in the FHCA around poles that have fuses, air switches, clamps or other devices that could create sparks. After a pole has been cleared, a spark falling within the 10-foot radius would be much less likely to ignite a fire.

Alternative Strategies for Potential Future Deployment. Moving forward, Rocky Mountain Power vegetation management is planning to implement the three mitigation projects described above. Rocky Mountain Power will consider and evaluate other strategies and emerging industry standards and best practices in the arena of wildfire mitigation. Along these lines, Rocky Mountain Power may implement additional vegetation management strategies in a subsequent wildland fire protection plan. In particular, Rocky Mountain Power vegetation management is considering whether certain strategies might be employed to reduce the general inventory of trees that could fall into a line.

Vegetation Inventory Reduction Projects. Rocky Mountain Power vegetation management has experimented with inventory reduction projects aimed at reducing the overall volume of trees with the potential to create clearance issues or become high risk at some point in the future. Pacific Power is experimenting with some inventory reductions programs as part of its wildfire mitigation plan in California. Depending on the results of those projects, Rocky Mountain Power vegetation management may consider implementing similar projects in Utah.

The goal of inventory reduction is to remove trees before such trees ever require vegetation work. Unless property rights in the right-of-way were substantially enlarged, it would not be feasible to remove all trees that have the potential to implicate clearance issues or become high-risk trees (i.e., by definition, all trees eventually become high-risk trees when they die). Instead, an inventory reduction program targets specific areas of particular concern, with the goal of materially reducing the total number of trees that could eventually pose a risk of vegetation contact. Determining which areas and trees to target implicates a certain degree of subjective judgment and evaluation of local conditions. Factors for consideration include tree species, tree height, weather patterns, topography, line design and tree disease patterns.

Right-of-Way Enhancements. Vegetation management practices are typically limited by Rocky Mountain Power's legal rights in the right-of-way. Width of the defined right-of-way is obviously a key factor. On higher voltage transmission lines, wide easements permit vegetation management to use IVM practices and maintain generous clearance distances. Not surprisingly, there are very few vegetation contacts on lines located in those very wide easements. If similar width easements were obtained for lower voltage transmission and distribution facilities in the FHCA, similar vegetation management practices could be employed. The primary barriers to this approach are cost and aesthetics. Obtaining additional property rights entails additional capital investment. In terms of aesthetics, distribution facilities located near residential structures frequently overlap with areas where customers are particularly concerned with the landscape. Nonetheless, strategies might be considered to address such concerns. First, the costs of additional easements rights may be reduced by solely obtaining rights to remove tree species that could, when mature, grow tall enough to strike a power line in the more narrowly defined utility right-of-way. Second, aesthetic concerns might be addressed by focusing on line miles where there are few residential structures near the line.

Lines traversing public lands pose distinct challenges, as land managers have frequently been opposed to vegetation management activities outside the proscribed width of the right-of-way specified by permit. With growing concerns about wildfire, however, many public bodies are reassessing land management policies. The relatively recent passage of legislation by the U. S. Congress suggests that utility companies may receive wider latitude in their vegetation management activities in the future. Section 211 of the Omnibus Appropriations Act of 2018 amended Title V of the Federal Land Policy and Management Act. The new law, codified at 43 U.S.C.A. § 1772, establishes a formal procedure for submission and approval of vegetation management plans, with an emphasis on standardized, consistent plans that minimize the need for case-by-case approvals for high-risk tree removal. Rocky Mountain Power understands that the Bureau of Land Management (BLM) and the United States Forest Service (USFS), the two federal agencies that issue most of Rocky Mountain Power's rights-of-way permits, are engaged in a rulemaking to "develop a consolidated and coordinated process for the review and approval of plans." 43 U.S.C.A. § 1772(c)(4)(A). When those regulations are finalized, Rocky Mountain Power anticipates that it will submit a vegetation management plan under 43 U.S.C.A. § 1772(c)(1) to both the BLM and the USFS. Rocky Mountain Power is hopeful that those submissions will eventually result in permission to conduct vegetation management activities on a wider right-of-way path.

5. Environmental

Rocky Mountain Power is developing a Wildlife Protection Plan (WPP) focused on preventing wildlife contacts in the FHCA and other areas where species, habitat, utility equipment and other factors can present elevated wildfire risk. The WPP is being modelled after the methods and standards developed in Rocky Mountain Power's Avian Protection Plan (APP), which has been implemented for several decades and significantly improved over time. The APP has proven effective in reducing bird mortality and associated reliability risks, and it can serve as a model for similar efforts to address wildfire risks caused by other animals. The overall benefit of a WPP is to directly reduce the risk of fires and outages associated with wildlife-electrical contacts in targeted areas.

5.1. Description of the Existing Avian Protection Plan

Rocky Mountain Power's service territory supports a diverse array of migratory birds and other wildlife[13] that have the potential to interact with its electrical facilities. Rocky Mountain Power has developed and implemented an APP addressing operations within its Utah service territory in cooperation with the U.S. Fish and Wildlife Service (USFWS), which identifies processes to minimize avian electrocutions and collisions with electrical facilities that may result in an avian mortality or injury and subsequent potential for a disruption in electrical service. The APP outlines Rocky Mountain Power policies and procedures for responding to bird mortalities and nests; avian protection standards for transmission, distribution and substation facilities; and risk assessment procedures to identify areas in which to implement proactive facility retrofits to reduce electrocution and collision risks of protected birds. Retrofit refers to actions taken to modify a structure to prevent avian or wildlife mortalities. This may include installation of after-market bird protection products (such as covers), reframing to achieve avian-safe separations

[13]For purposes of this plan, "wildlife" refers to and includes nonprotected birds (e.g., birds that are not listed under the Migratory Bird Treaty Act [MBTA], Endangered Species Act [ESA], and/or Bald and Golden Eagle Protection Act [BGEPA]) and mammals or other wild animals that may climb, land on, or interact with electrical infrastructure. This may include state and/or federally protected nonavian species (e.g., threatened/endangered species) and nonprotected species. Examples of "wildlife" that may interact with electrical infrastructure include raccoons, squirrels, climbing snakes, starlings, rock doves, collared doves, etc.

between wires, or rebuilding structures to meet avian-safe designs. Rocky Mountain Power's program was used as a template for the national APP guidelines developed by Avian Power Line Interaction Committee (APLIC) and the USFWS in 2005. Rocky Mountain Power's APP is a living document that is reviewed and updated as needed through coordination with the USFWS. The APP includes standardized program components for Rocky Mountain Power transmission and distribution operations and includes proactive survey and retrofitting efforts prioritized by avian risks at different circuits.

Although Rocky Mountain Power's APP and related policies were developed with a focus on protecting eagles, other raptors and other migratory birds from electrocution and collision mortality, APP activities also mitigate wildfire risk associated with these types of incidents. In addition, APP efforts provide secondary benefits of minimizing other wildlife contacts, involving nonprotected birds and mammals, further mitigating the wildfire risk associated with those incidents. Finally, existing APP procedures also address potential fire risks posed by bird nests and provide wildland fire protection in facilitating the removal or safe relocation of bird nests.

In 2009, Rocky Mountain Power's transmission and distribution operations developed and implemented two policies: (1) Avian Protection Plan Policy and (2) Bird Protection Policy for Substations that address management of protected bird incidents with Rocky Mountain Power-owned distribution, transmission and substation facilities. These policies outline Rocky Mountain Power's avian-safe construction design standards, which include requirements to construct and design all new or rebuilt equipment poles in all areas and all new or rebuilt lines in rural areas in adherence with Rocky Mountain Power's avian-safe constructions standards, thereby reducing the risk of protected bird or other wildlife incidents. Rocky Mountain Power implements these policies throughout its service territory.

Rocky Mountain Power's avian-safe construction design standards follow APLIC guidance documents: Suggested Practices for Avian Protection on Power Lines: The State of the Art in 2006 and Reducing Avian Collisions with Power Lines: State of the Art in 2012. Avian-safe designs for transmission and distribution structures are achieved by framing poles with 60-inch horizontal and 40-inch vertical phase-to-phase and phase-to-ground separation, extending the center phase of a three-phase crossarm design 36 inches from the crossarm (pole), or by using covers to protect against potential phase-to-phase and phase-to-ground contact by birds or other wildlife. Phase-to-phase and phase-to-ground separation distances are based on the skin-to-skin dimensions of eagles as recommended by APLIC for utilities located in areas where eagle interactions may occur. Because eagle interactions within substations are unlikely, Rocky Mountain Power's avian-safe substation standards are based on the measurements of the largest birds commonly observed in substations and are sufficient for the protection of hawks, owls, ravens and smaller birds. Consequently, Rocky Mountain Power's avian-safe substation designs apply covers or barriers where there is less than 30 inches of vertical separation and/or less than 46 inches of horizontal/diagonal separation between phase-to-phase or phase-to-ground potential points of contact. Line markers are used as needed to minimize avian collision risks. Nest management – potentially including nest discouraging, removal or relocation – may be employed as needed to address nests that pose fire, safety, reliability or bird electrocution risks. Rocky Mountain Power maintains and complies with applicable federal and/or state permits authorizing management of migratory bird nests and handling of carcasses. All avian protection standards and products are reviewed periodically and updated to ensure that the best available products and methods are being used.

5.2. Description of the New Wildlife Protection Plan

While many elements of the existing APP program already provide some degree of wildland fire protection, expansion of certain activities can enhance these efforts. As indicated above, Rocky Mountain Power T&D environmental services proposes to develop and implement a WPP that will leverage proven APP practices and methodologies and, where needed, apply new approaches to respond to wildlife incidents and implement proactive measures. The ultimate goal of the proposed WPP is to reduce the potential for wildlife incidents within FHCA boundaries and emerging focal areas.

To be clear, the WPP will be funded separately from current funding commitments made to implement the APP, as APP priorities are based on agreements with federal and state agencies to address potential risks to protected birds. The WPP draws from the experience and knowledge gained through APP implementation, and integrates applicable elements of the APP, but the WPP does not replace the APP. Along these lines, the WPP is intended to complement, not contradict APP components. The section below provides more detail regarding these components. The WPP will be a living document and updated as appropriate.

Incident Tracking. In conjunction with existing APP activities, Rocky Mountain Power tracks reported protected bird incidents and nest management activities using Rocky Mountain Power's Wildlife Incident Tracking System (WITS). Data stored in WITS includes species, location, outage identification numbers and remedial actions (typically retrofitting the structure where the incident occurred) through completion. Data in WITS is also used to identify potential areas of high risk for avian incidents and focal zones to implement proactive retrofitting efforts.

Within FHCA boundaries, we propose to evaluate existing outage and GIS data to assess wildlife incident risks, frequency, associated structure types and locations. This information will be used to identify possible correlations between wildlife interactions, structure/equipment type, and habitat that can then prioritize remedial actions to address wildlife incidents. In addition, similar factors outside of the FHCA will be considered as possible emerging focal areas. Existing data sources and software will be assessed to determine appropriate reporting needs for wildlife incidents, and to seek efficiencies with existing IT resources. Applicable guidance will be developed and distributed to affected employees in these areas. This would be a Rocky Mountain Power-wide effort, so the cost of an IT solution would be shared throughout Rocky Mountain Power T&D operations, and employee time associated with reporting and tracking incidents would be included with T&D operations and environmental services departments for Rocky Mountain Power.

Reactive Actions. Consistent with the APP identifies, Rocky Mountain Power responds to avian incidents by taking remedial action, which include retrofitting the pole where the incident occurred. Additional poles are retrofitted depending upon the incident; for example, five poles in each direction are retrofitted in response to eagle mortalities and multiple spans may be marked in response to bird collisions in areas of suitable habitat. Although Rocky Mountain Power is not required to retrofit poles in response to nonprotected wildlife incidents, existing policies encourage retrofits as appropriate to prevent future outages.

As part of the WPP, Rocky Mountain Power will implement additional remedial actions to address wildlife incidents including nonprotected birds and other wildlife in the FHCA. The mechanism for these remedial actions would be similar to the current remedial actions taken in response to protected bird incidents under the APP. Rocky Mountain Power proposes to, at a minimum, retrofit the pole where the wildlife incident occurred, or is suspected to have occurred, to prevent the event from recurring at that location. Retrofitting a pole involves bringing the pole into compliance with Rocky Mountain Power's avian-safe construction design standards described above. Applicable policies and guidance documents will be developed to support implementation of this activity. For the FHCA, planned rebuild work on distribution and transmission circuits will address most areas where wildlife incidents occur, thereby not warranting separate action. However, if a wildlife incident occurs on a pole within the FHCA that is not otherwise identified for remedial action, it will be retrofitted to prevent further wildlife contacts. Data from the past nine years has indicated an average of 110 wildlife-caused outages per year in the FHCA. Assuming that the majority of poles within the FHCA will be addressed through other projects, it is estimated that 10% of wildlife-caused outages in the FHCA may require additional work.

Proactive Actions. Rocky Mountain Power also plans to implement new proactive measures to address the potential for wildlife incidents. Such measures focus on (a) nest management, (b) substations, and (c) line elements.

Nest Management. Under the existing APP, considerable work is done to manage bird nests. During line inspections and operational activities throughout Rocky Mountain Power's service territory, field personnel identify nests on facilities that may have the potential to result in fires, outages and other operational problems. These nests are categorized as "problem nests" and are documented and managed as appropriate through coordination with Rocky Mountain Power's environmental services department and as authorized under state and federal permits. Proactive nest management may include removing or relocating the nest, discouraging birds from nesting in areas on structures that may lead to operational issues, providing an alternative nest site (nest platform), trimming nest material, installing an avian guard, and/or ensuring that surrounding utility facilities are avian-safe. Active nests (those with eggs or young) of species listed under MBTA are protected and management activities may only be implemented in accordance with Rocky Mountain Power's Migratory Bird Special Purpose Utility Permit (issued by USFWS) and applicable state permits. In the case of an emergency situation (circumstance where a bird nest poses impending danger of fire, safety risk to crew, avian electrocution, or threat to human life or property that requires immediate action), Rocky Mountain Power crews will take immediate, appropriate nest management actions, in consultation with environmental services, who will communicate this with the regulatory agencies. Nest management activities are reported annually to federal and state wildlife agencies in accordance to permit requirements. Nest management that is needed for eagles or federally listed threatened or endangered species requires additional permitting and agency coordination before proceeding; the need for this type of permitting is infrequent, can take a significant amount of time to obtain (months to years) and typically will have associated stipulations for mitigation and monitoring.

As part of the WPP, environmental services proposes to implement more proactive measures regarding nest maintenance and management within the FHCA. These actions are intended to reduce wildfire risk directly related to nests on Rocky Mountain Power infrastructure and provide nesting opportunities on nonenergized sites away from lines. Such actions may include the following

- Increased maintenance of Rocky Mountain Power-owned nest platforms on or near energized poles. First, a nest platform inventory may be conducted within the FHCA to verify locations, status/activity and prioritize maintenance work. Maintenance work would be designed to reduce wildfire risk. For example, some species, particularly osprey and ravens, bring baling twine, metal, wire or other rubbish to their nests. Removing these objects from nests can reduce the volume of materials that could be a potential fire ignition source if there was contact with electrical equipment. To adhere to avian regulations and permits, maintenance work would be done when nests are inactive and for species that are covered under existing Rocky Mountain Power permits (e.g., migratory birds; non-eagles, nonendangered or threatened species). Based on the current number of "problem" nests documented in WITS in Utah since 2015, the company estimates that 27 nests within the FHCA will need to be maintained annually.
- Installation of nest platforms and nest boxes. Rocky Mountain Power plans to install additional nest platforms where appropriate in the FHCA, to facilitate removal of problem nests from Rocky Mountain Power facilities. In areas where dead snags along utility rights-of-way in the FHCA may be fire hazards, Rocky Mountain Power may remove these trees as part of vegetation management activities. Because nesting cavities located in such dead snags may be limited and important to cavity-nesting species, Rocky Mountain Power proposes to partner with groups that install nest boxes for American kestrels, screech owls and other cavity nesting birds. Support of these nest box programs would help offset our impact to these species, and would provide alternative nesting sites that are maintained and do not pose a fire risk.

Substations. Under current practices, avian protection devices are installed (or the presence of existing avian protection devices is verified) at substations during routine planned maintenance. Such avian protection devices include covers and/or barriers at equipment locations where there is an increased risk of electrocution (e.g., circuit breaker bushings, substation transformer bushings and arresters, switches, and station service transformers, cutouts and arresters).

As part of the WPP, the company is evaluating whether any wildlife guards could be employed in substations to minimize wildlife contacts.

Lines and Line Elements. Risk assessment surveys are currently conducted as needed to assist with identifying structures for proactive retrofitting efforts. These surveys involve visual inspection of lines, structures, equipment and rights-of way to identify evidence of avian use, mortalities, nests and risk. Circuits and regions are prioritized throughout Rocky Mountain Power's service territory based on avian mortality history, eagle-specific risks and incident trends. Circuit priorities are re-assessed annually to identify current conditions, including availability of suitable avian habitat, avian population shifts, prey base, surrounding land use and proactive retrofitting activity completion status. These prioritizations are reviewed during routine APP meetings with the USFWS. Within prioritized circuits, field risk assessment surveys are conducted to identify high-risk poles and determine appropriate retrofitting needs.

In addition to circuit prioritization, a spatial-based analysis may be conducted to determine focal areas to implement proactive retrofit activities. Spatial-based analysis uses density and heat mapping within ArcGIS to identify high-risk avian environments. Using GIS modeling, the highest risk poles in a specific area may be identified by considering habitat and pole-related variables such as pole configuration, presence of equipment, existing avian protection, and other factors determined to be significant based on existing local data.

In addition to circuit prioritization, a spatial-based analysis may be conducted to determine focal areas to implement proactive retrofit activities. Spatial-based analysis uses density and heat mapping within ArcGIS to identify high-risk avian environments. Using GIS modeling, the highest risk poles in a specific area may be identified by considering habitat and pole-related variables such as pole configuration, presence of equipment, existing avian protection, and other factors determined to be significant based on existing local data.

The planned rebuild work on distribution and transmission circuits in the FHCA, discussed in the system hardening section, will incorporate current best practices to limit wildlife contacts. In particular, use of covered conductor virtually eliminates avian contacts. Consequently, most lines in the FHCA will not require retrofits. Lines which are not being rebuilt, however, will be assessed for retrofitting. The company will coordinate WPP retrofit projects with other long-term planning objectives.

5.3. Other Environmental Considerations

Rocky Mountain Power's wildland fire protection efforts will require coordination with governmental agencies and may also require additional permitting related to trust resources (e.g., cultural, water and biological resources). To facilitate proactive wildland fire protection work and to avoid possible regulatory violations, Rocky Mountain Power's environmental services assesses regulatory requirements and actively coordinates with applicable agencies. This subsection identifies coordination needs, surveys and measures that can be taken to streamline agency authorizations for maintenance work and wildland fire protection activities. In addition, collaborative efforts with external organizations are proposed where such efforts would provide an overall reduced wildfire risk (e.g., fuels reduction, habitat enhancement).

Some wildland fire protection activities may have environmental impacts and necessitate agency coordination or permitting before implementation. These activities may be related but not limited to vegetation management, ground disturbance, access road creation or maintenance, changes to right-of-way boundaries or conditions, seasonal timing of work and potential impacts to threatened/endangered/sensitive species, cultural resources, wetlands or other natural resources. In some cases, proactive measures can be taken to communicate with agencies and resolve potential environmental issues that could arise in future work.

Coordination between environmental services and various other Rocky Mountain Power business units and governmental agencies is common. Some examples of areas requiring such coordination are:

- Access road filling, improvements, rerouting or expansions
- Power line structure modification or replacements
- Ground-disturbing activities
- Activities on public lands
- Wetland and waterway impacts
- Implementation of fire minimization Best Management Practices (BMPs) from the APLIC document Best Management Practices for Electric Utilities in Sage-grouse Habitat, as applicable, in Rocky Mountain Power projects
- Environmental impacts associated with undergrounding power lines
- Seasonal activity buffers and other restrictions to protect nesting birds, sage-grouse leks, big game winter range, winter bald eagle roosts and other sensitive wildlife

- Agency stipulations regarding rare plant or wildlife surveys
- External habitat efforts that promote low growing, fire resilient species and pollinator habitat in rights-of-way
- Any other environmental impacts identified through use of an environmental checklist

Many initiatives require extensive and detailed involvement by environmental services. For example, certain projects, both existing and potential, require biological and cultural review and/or surveys to support implementation. A few possibilities are outlined below:

- **O&M Plan.** Rocky Mountain Power environmental services will continue efforts with federal land management agencies, including the respective state offices of the BLM and USFS, to update (or develop as the case may be) an O&M plan that guides Rocky Mountain Power's maintenance activities on lands managed by the respective agency and streamlines permitting activities. These efforts have been ongoing for several years with the Utah BLM, and such collaboration can be valuable to facilitate wildland fire protection activities. Future iterations may include permit consolidation (master permits) by forest or field office, which would allow for more efficient and timely response to conditions or wildfire threats.
- **Fuel Breaks.** There may be opportunities to use Rocky Mountain Power rights-of-way as fuel breaks. Rocky Mountain Power environmental services may coordinate with state, federal, and other agencies to identify opportunities, challenges and potential requirements.
- **Habitat Enhancements.** Habitats can be managed to reduce the wildfire risk, and there may be partnership opportunities with third parties already conducting habitat enhancement work. Examples include rangewide sage-grouse conservation efforts and state or local efforts, such as Utah's Watershed Restoration Initiative (WRI). The Utah WRI implements habitat conservation projects, including fuels reduction efforts that can limit the frequency and intensity of destructive fires, reduce fire-prone invasive plant species and restore degraded habitats to functioning, fire resilient watersheds. WRI brings together public and private partners to develop and implement projects, leverages matches an average of 5:1 and addresses environmental and cultural resource clearances that would otherwise be challenging for Rocky Mountain Power to conduct on its own. Rocky Mountain Power environmental services may work with WRI to identify existing projects for funding or develop partnerships for projects that include beneficial treatments in Rocky Mountain Power rights-of-way, especially projects located in the FHCA.

- **Pollinator Habitat Conservation.** Pollinator habitat tends to mitigate wildfire risk, because pollinator habitat often includes vegetation more resistant to wildfire ignition and spread. Rocky Mountain Power environmental services may explore opportunities to implement pollinator habitat conservation practices, as appropriate, in Rocky Mountain Power rights-of-way. To this end, Rocky Mountain Power environmental services plans to collaborate with other utilities, agencies and industry groups (e.g., EEI) to identify current best practices for maintaining pollinator habitat, and therefore fire resilient habitat, in utility rights-of-way.

6. Construction Standards

Construction standards have been developed for the use of Rocky Mountain Power personnel and contractors in the construction, operation and maintenance of Rocky Mountain Power's electric distribution facilities. Systemwide construction standards play an important role in the continued expansion of Rocky Mountain Power's facilities, as well as ensuring that modifications to existing facilities are in line with updated industry practices. Standards properly developed and applied accomplish the following objectives:

1. Establish desired design criteria and performance levels
2. Ensure uniform, safe and economical construction practices
3. Provide information on materials and their proper application
4. Minimize engineering and estimating time
5. Provide the basis for automated material and labor determination for estimates and work orders

Each standard is typically re-evaluated within 10 years of its publication date to ensure it is in accordance with current codes and beneficial to Rocky Mountain Power and its customers. As discussed previously, Rocky Mountain Power has identified geographic areas with the greatest wildfire risk, which are designated as in the Fire High Consequence Area (FHCA). After designating the FHCA, the Rocky Mountain Power engineering standards department completed and published construction standards for certain types of equipment that are approved for new construction in the FHCA. In addition, the standards department has identified certain equipment, the use of which is discouraged in the FHCA. Map layers showing the FHCA are available in the company's internal mapping applications as a guide for estimators to determine where to use these construction standards.

General FHCA Applications. Certain equipment has design characteristics that make the equipment less likely to ever be involved in a fire ignition, as compared to alternatives frequently used in the construction of electrical facilities. For example, many traditional fuses are commonly referred to as expulsion fuses because such fuses could emit a shower of sparks if operated. Obviously, the sparks from an expulsion fuse can ignite a wildfire if a fuse operates in an area with dry wildland vegetation. There are, however, alternatives to traditional expulsion fuses. A fuse that does not emit a shower of sparks on operation is commonly referred to as a non-expulsion fuse. Because the non-expulsion fuse does not emit sparks, its use mitigates wildfire risk. Accordingly, the engineering standards department has researched non-expulsion fuses and created a construction standard for using such equipment on Rocky Mountain Power facilities in the FHCA. Other types of equipment have also been evaluated. With respect to distribution structures, two categories of equipment were identified as follows:

- **FHCA Exempt** standards identify equipment that has been designed to mitigate the risk of fires in high fire-threat areas. See Figure 24.
- **FHCA Non-Exempt** standards have been identified as not mitigating the risk of fires in FHCA. In other words, FHCA non-exempt equipment has a greater likelihood of emitting sparks. FHCA-non-exempt standards are marked at the top of the first page with the symbol shown in Figure 25.

(Cal Fire uses the terms "exempt" and "non-exempt" because the use of certain equipment exempts a pole from pole clearing requirements. This terminology has become accepted in the industry, and Rocky Mountain Power has, therefore, used the exempt and non-exempt terms in its construction standards.) There are of course devices that are neither FHCA Exempt nor FHCA Non-Exempt, which may continue to be used in the FHCA as standard design, so long as there is no FHCA Exempt alternative required for such construction. Standards for FHCA Exempt devices are marked with the following symbol:

Figure 24. Symbol for "FHCA Exempt"

To develop these construction standards, Rocky Mountain Power referred to the Cal Fire Power Line Fire Prevention Field Guide (2008 Edition).

In addition to creating construction standards for equipment that mitigates fire risk when used (and is designated as approved for use in the FHCA), work has also been completed to identify certain equipment that increases the risk of wildfire when used. Consequently, standards have been developed to designate equipment that is not allowed for use in the FHCA. Such equipment may continue to be used in normal construction activities outside the FHCA. But the standard for such equipment will be designated as FHCA Non-Exempt and marked at the top of the first page with the following symbol:

Figure 25. Symbol for "FHCA Non-Exempt"

The standards department continues to evaluate and add new devices and construction methods to the FHCA standards regularly as new technologies becomes available.

7. System Hardening

Rocky Mountain Power's electrical infrastructure is engineered, designed and operated in a manner consistent with prudent utility practice, enabling the delivery of safe, reliable power to all customers. When installing new assets, Rocky Mountain Power is committed to incorporating the latest technology and engineered solutions. When conditions warrant, Rocky Mountain Power may engage in strategic system hardening, which means replacing existing assets (or, in some circumstances, modifying existing assets using a new design and additional equipment) to make the assets more resilient. Recognizing the growing risk of wildfire, Rocky Mountain Power proposes to substantially supplement existing asset replacement projects with system hardening programs designed to mitigate specific operational risks associated with wildfire.

System hardening programs are designed in reference to the equipment on the electrical network that could be involved in the ignition of a wildfire. In general, system hardening programs attempt to reduce the occurrence of events involving the emission of sparks (or other forms of heat) from electrical facilities. No single program mitigates all wildfire risk related to all types of equipment. Individual programs address different factors, different circumstances and different geographic areas. Each program described below, however, shares the common objective of reducing overall wildfire risk associated with the design and type of equipment used to construct electrical facilities. In prioritizing particular design or equipment elements, these programs can also consider environmental factors impacting the magnitude of a wildfire. Dry and windy conditions pose the greatest degree of risk. Consequently, system hardening programs may specifically attempt to reduce the potential of an ignition event when it is dry and windy, by looking at equipment that is more susceptible to failure or contact with foreign objects when it is dry and windy.

It must be emphasized, however, that system hardening cannot prevent all ignitions, no matter how much is invested in the electrical network. Equipment does not always work perfectly and, even when manufactured and maintained properly, can fail; in addition, there are external forces and factors impacting equipment, including from third parties and natural conditions. Therefore, Rocky Mountain Power cannot guarantee that a spark or heat coming from equipment owned and operated by Rocky Mountain Power will never ignite a wildfire. Instead, Rocky Mountain Power seeks to reduce the potential of an ignition associated with any electrical equipment. To this end, Rocky Mountain Power plans to make substantial investments with targeted system hardening programs.

For clarity, it is worth noting that system hardening is a concept closely related to other wildland fire protection strategies discussed in this plan. Rocky Mountain Power is committed to use the best designs and technologies when completing corrections of identified conditions, as discussed in the prior section on inspections and corrections, and when constructing new line extensions, which is addressed in the next section. Also along these lines, Rocky Mountain Power developed new design standards applicable to new construction in areas of elevated wildfire risk, described in the construction standards section. The idea of "system hardening" applies in these contexts, as Rocky Mountain Power certainly plans for new construction to be "hardened" against wildfire risk. This particular section on system hardening, however, is geared toward specific programs aimed at making existing facilities more resistant to wildfire, even though those existing facilities are fully functional and do not require any corrective work under current utility best practices.

7.1. FHCA Line Rebuild Program

As a central part of this wildland fire protection plan, Rocky Mountain Power is planning to rebuild a number of selected power lines. The rebuild program is well above and beyond standard utility practice. It is not typical to tear down and rebuild an entire line. Instead, particular equipment components are replaced on an as-needed basis. Likewise, a particular pole might be replaced if necessary. Thus, over time, particular segments of a line may be "rebuilt" as part of an ongoing process of smaller, individual capital improvements at specific pole locations. This approach, under normal circumstances, is typically the most cost effective way to provide safe and reliable electric service.

Because of the heightened risk of a catastrophic wildfire in the FHCA, Rocky Mountain Power is spearheading a new program to comprehensively rebuild selected lines. The rebuild program will involve new construction from the ground up and for the entire length of a selected segment of a line, including the installation of new conductor and new poles. In other words, the end result of a project will be a brand new line, as if there had not previously been a line at that location. New construction of an entire line is expensive. Rocky Mountain Power proposes to make this investment because a comprehensive approach will be the most efficient way to upgrade all equipment on a line at one time and make all components of the entire line more resilient against wildfire. It is also the most efficient way to make a transition to covered conductor, which is discussed in greater detail below.

The company used different criteria to determine which lines are included within the line rebuild program. First, because of the heightened risk in the FHCA, all lines included in the rebuild program are located at least partially in the FHCA. Certain segments of a rebuild might extend outside the FHCA, based on the location of substations or protective devices. In general, however, the vast majority of rebuild is in the FHCA. Second, the company evaluated the average age of poles on the line. If the average age of poles was above 45 years of age, the line was included in the rebuild program. Third, even if the average age of poles was less than 45 years of age, particular lines were hand-selected for rebuild based on local knowledge of the electrical infrastructure.

In using average pole age as the objective criteria, we must emphasize that pole age of an individual pole, alone, does not necessarily have a direct correlation to risk; an old pole may be perfectly strong, whereas a younger pole may suffer decay because of specific conditions at that pole location (i.e., soil, drainage, insects, etc.). In other words, continued use of an older pole (i.e., even a pole much older than 45 years of age) is appropriate for safe and reliable service unless there is an observable defect in the pole. And the normal industry standard is to replace a pole only when that particular pole manifests a certain degree of observable weakness. Nonetheless, the heightened risk of wildfire warrants selected application of a more aggressive approach, and average pole age is an appropriate criteria to determine which segments of line are the highest priority candidates for a rebuild. When an entire group of assets is assessed from the perspective of asset age (i.e., a segment of line, with all of its components), there is some direct relationship with risk. As the average age of assets on a line increases over time, the probability that some portion of equipment will fail increases to some degree. Pole age is a data point maintained by the company, and the average age of poles is highly indicative of the age of all of the assets on the line (especially in relative terms to other lines). Consequently, the company has used average pole age as the objective measure by which to qualify line segments in the FHCA for the rebuild program.

After identifying line segments based on average pole age, the company also added other line segments of special concern. As discussed in the risk assessment section above, the FHCA is a geographic area, reflecting computer simulation modeling of wildfire spread and its impacts on people and property. That larger risk assessment does not necessarily account for the unique circumstances of a specific power line at any given location. Because of topography, some power lines have certain operational challenges that other lines do not have. For example, some lines are simply easier to patrol because they run parallel to an established roadway. Other lines, however, might have been constructed up a steep mountain slope. Thus, certain lines were added to the rebuild project because of their unique characteristics, assessed in context with the immediately surrounding landscape. In general, an FHCA line traversing dense, tall vegetation and crossing exposed ridges with frequent high winds was considered as a rebuild candidate, even if the average age of poles was less than 45 years of age.

Covered Conductor. Historically, the vast majority of high voltage power lines in the United States – and in Rocky Mountain Power's service territory – were installed with bare overhead conductor. As the name "bare" suggests, the wire is all-metal and exposed to the air. For purposes of wildfire mitigation, a new conductor design has emerged as the preferred approach. Most of the projects in the FHCA Line Rebuild Program will involve the installation of covered conductor. Covered conductor is also frequently called insulated conductor or insulated wire. Sometimes, with some variations in products, it is also called spacer cable, aerial cable, or tree cable.

The dominant characteristic of covered conductor is that the metal conductor which actually carries electricity is sheathed in a plastic covering. As a comparison for the lay person, covered conductor is like an extension power cord that you might use in your garage. The plastic coating provides insulation for the energized metal conductor inside the plastic coating. To be clear, covered conductor is not insulated enough for people to directly handle an energized high voltage power line (as discussed below). But the principle is the same. The plastic sheathing provides an insulating effect. It is this insulating effect which reduced the risk of wildfire, by greatly reducing the number of faults that would have occurred had bare conductor been used.

Variations in covered conductor products have been used in the industry for decades. Due to many operating constraints, however, use of covered conductor tended to be limited to locations with extremely dense vegetation where traditional vegetation management was not feasible or efficient. Recent technological developments, however, have markedly improved covered conductor products, reducing the operating constraints historically associated with the design. These advances have improved the durability of the project and reduced the impact of thermal insulation (i.e. because bare wires are exposed to air, bare wires can cool easier). There are still logistical challenges with covered conductor. Above all, the wire is heavier, especially when carrying snow or ice in the cold Utah weather, meaning that more and/or stronger poles are required when using covered conductor. And the product itself is more expensive than bare conductor.

The wildfire mitigation benefits of covered conductor are significant. As discussed in the risk assessment section, a disruption on the electrical network, a fault, can result in emission of spark or heat that could be a potential source of ignition. Covered conductor greatly reduces the potential of many kinds of faults. For example, contact from object is major category of real-world faults which can cause a spark. Whether it is a tree branch falling into a line or a Mylar balloon carried by the wind drifting into a line, contact from those objects with energized bare conductor causes the emission of sparks. If those same objects contact covered conductor, the wire is insulated enough that there are no sparks. Likewise, many equipment failures are a wildfire risk because the equipment failure then allows a bare conductor to contact a grounded object. Consequently, covered conductor greatly reduces the risk of ignition associated with most types of equipment failure. For example, if a crossarm breaks, the wire held up by the crossarm often falls to the ground (or low and out of position, so that the wire might be contacting vegetation on the ground or the pole itself). In those circumstances, a bare conductor can emit sparks (or heat) that can cause an ignition. The use of covered conductor, in those exact same circumstances, would almost certainly not lead to an ignition, because the insulation around the wire is sufficient enough to prevent any sparks and limit energy flow, even when there is contact with an object.

Covered conductor is especially well-suited to reduce the occurrence of faults reasonably linked with the worst wildfire events. Dry and windy conditions pose the greatest wildfire risks. Wind, in particular, is the driving force behind catastrophic wildfire spread. At the same time, wind has distinct and negative impacts on a power line. The wind blows objects into lines; a strong wind can cause equipment failure; and even parallel lines slapping in the wind can cause sparks. Covered conductor specifically reduces the potential of a catastrophic ignition event, because covered conductor is especially effective at limiting the kinds of faults that occur when it is windy. Taken together, these substantial benefits warrant the use of covered conductor in areas with a high wildfire risk.

While the wildfire mitigation benefits are substantial, certain disadvantages with covered conductor need to be addressed as well. In addition to the added expense and operational limitations mentioned above, the benefits that covered conductor provide also lead to a unique challenge. With bare conductor, the utility usually learns about an event relatively quickly, because a significant or persistent fault typically results in an outage. When an outage is reported, the utility can generally patrol the line to identify any obvious structural problems. A bare conductor on the ground may sometimes still be energized. If the contact with ground (or vegetation with a path to ground) mimics the use of electricity by downstream customers, the protection equipment on the line may not activate to open a breaker and de-energize the line. Nonetheless, a high impendence fault tends to be temporary and will usually lead to an outage in a relatively short term. In sum, a displaced bare conductor will generally be spotted and corrected within a relatively short timeframe.

Covered conductor works differently. Because the covered conductor is designed to avoid a fault, it is also likely to remain energized, even if not properly attached to a pole. From a wildfire mitigation perspective, not learning about an event is a sign that covered conductor is working as intended (i.e. a fire cannot have started if no sparks were emitted). But the ability for covered conductor to avoid an electrical fault and stay energized implicates a separate set of concerns. If a tree branch momentarily touches a covered conductor, it is not an issue, because the line simply continues to operate as intended. But when the covered conductor is physically displaced from its designed position, it can be difficult to identify. Taking again the example of a broken crossarm, a covered conductor hanging a few feet off the ground, perhaps even contacting tall, dry grass or lying across Gambel oak, will almost certainly not experience a fault right away, which is a good outcome. In that case, an ignition will not occur. A downed or low-hanging line is always, however, a safety hazard. Because the insulation on the covered conductor works to prevent an outage in a situation like this, the line remains energized. As a fundamental rule, a person should never touch or handle any energized high voltage line, even if it is insulated. Touching an insulated conductor is certainly less dangerous than touching a bare conductor, and incidental contact with a covered conductor should be harmless. But there are still risks of electrical contact injury to any person touching the wire. The insulating effect of the sheathing on the covered conductor in not rated to prevent the flow of electricity to a person in direct contact with the ground, and a person touching a covered conductor could still be seriously injured. If the wire has actually broken (i.e., because a tree fell into the line), there is a risk of contacting the two exposed ends.

In sum, at a very basic level, covered conductor is safer overall compared to bare conductor. Not only does covered conductor reduce the risk of wildfire, it is less dangerous to contact a covered conductor compared to a similar voltage bare conductor. Combined with the substantial wildfire mitigation benefits, covered conductor is the preferred design for rebuild projects. There are, however, unique challenges implicated in making it harder to spot a low-hanging or downed line.

Rocky Mountain Power also evaluated the costs and benefits of underground design for the rebuild projects. The potential wildfire mitigation benefits are undeniable. While an underground design does not completely eliminate every ignition potential (i.e. because of above-ground junctions), it is the most effective design to most dramatically reduce the risk of any utility-related ignition. Unfortunately, because of cost and operational constraints, the functional realities of underground construction prevent widespread application as a wildfire mitigation strategy. Nonetheless, Rocky Mountain Power is using an underground design as part of the rebuild projects when functional and cost-effective. Through the design process, each individual rebuild project is assessed to determine whether sections of the rebuild should be completed with underground construction. As a practical matter, the great majority of the rebuilds will be covered conductor. This outcome is consistent with emerging best practices. Utilities in geographic areas with extreme wildfire risk, including in California and Australia, are trending heavily towards use of covered conductor, with limited applications of underground construction where appropriate. Indeed, sourcing material for the planned projects is challenging because of the industry trend towards use of covered conductor as a primary wildfire mitigation strategy. On a related note, the company remains willing to consider additional underground applications. Some communities and landowners may prefer, for aesthetic reasons, to pursue a higher cost underground alternative. Consistent with controlling electric service regulations, Rocky Mountain Power will work with communities or individual landowners who are willing to pay the incremental cost and obtain the necessary legal entitlements for underground construction, if covered conductor is the least cost option for a rebuild project.

7.2. Pole Replacement Program

As indicated above, all poles on a rebuilt line will be replaced as part of a rebuild program. The intent of the rebuild program is to comprehensively bring the line to a new condition. (In addition, the conversion to covered conductor often necessitates pole replacement anyway.) For lines in the FHCA which are not being rebuilt, Rocky Mountain Power is planning to replace selected poles through a pole replacement program. The company will prioritize poles for replacement based on pole age, and all poles in the FHCA over 45 years of age will be selectively replaced as part of the program.

In some applications, Rocky Mountain Power may replace a wooden pole with a steel or composite pole. In most applications, however, the company will continue to use wooden poles. A steel pole is obviously stronger than a wooden pole, meaning that it is generally less likely, in the same period of time, to fail. Because it is not flammable, a steel pole is also generally better at withstanding a wildfire burning through the area in which it is located without damage to the pole itself. A wooden pole, however, tends to perform extremely well, especially in Utah's arid climate. With that proven performance, a wood pole tends to be more cost effective in most standard applications. A steel pole will be used when greater strength is required. To mitigate against damage to a wooden pole, Rocky Mountain Power is investing in fireproof mesh wrapping to protect selected at-risk poles (see immediately below). In sum, the company determined that for most applications wooden poles are generally more cost-effective.

7.3. Fireproof Mesh Wrapping

Many wooden poles will be wrapped as part of Rocky Mountain Power's efforts to protect its own assets. The vast majority of wildfires do not have a utility-related ignition. Wildfires can burn through the area where an electric power line is located and cause massive damage to the line. Accordingly, Rocky Mountain Power plans to wrap wooden poles with a protective material. The fireproof mesh wrapping is intumescent, meaning that it swells in the event of a fire. That swelling protects the underlying wood. The manufacturers have tested the material at labs to demonstrate the material's effectiveness at protecting wooden poles from fire damage.

Wooden poles will be selected for wrapping based on perceivable wildfire threat to the pole. In essence, wooden poles in close proximity to at-risk fuels will be prioritized for treatment. There are three main categories of wooden poles that will receive wrapping treatment. First, many wooden poles installed as part of the FHCA Line Rebuild Program will be treated with fireproof mesh wrapping. After spending so much to rebuild a line, the company has a strong desire to protect the investment. Second, some existing wood poles in the FHCA will be wrapped on an as-needed. Poles that are relatively young, structurally sound, and have no outstanding observed maintenance needs affecting the strength of the pole fall into this category. Third, if a pole has experienced a history of fire damage from third parties performing controlled burns, fire wrap may be considered as an alternative.

7.4. Relays for Advanced System Protection Program

Rocky Mountain Power plans to replace electro-mechanical relays with microprocessor relays. Microprocessor relays provide multiple wildfire mitigation benefits. Microprocessor relays are able to exercise programmed functions much faster than an electro-mechanical relay. Above all, the faster relay limits the length and magnitude of fault events. After a fault occurs, energy is released, posing a risk of ignition, until the fault is cleared. Reducing the duration of a fault event reduces the risk that the fault might result in a fire. Microprocessor relays also allow for greater customization to address environmental conditions through a variety of settings, and are better able to incorporate complex logic to execute specific operations. These functional features allow for the company to use more refined settings for application during periods of greater wildfire risk. Finally, in contrast to electro-mechanical relays, microprocessor relays retain event logs that provide data for fault location and later analysis. In certain circumstances, this information can help the company locate and correct a condition prior to the condition leading to a more serious event. At a minimum, such information facilitates better knowledge of the network, possibly shaping future mitigation strategies. As part of replacing an electro-mechanical relay, the associated circuit breaker may also be replaced, as appropriate to facilitate the functionality of a microprocessor relay.

7.5. Non-Expulsion Fuse Installation Program

Rocky Mountain Power is systematically replacing all expulsion fuses in the FHCA with comparable non-expulsion devices. A standard expulsion fuse, industry standard for many decades, could emit a shower of sparks during operation. A fuse is a safety device that allows a release of energy to protect the line from too much current in the event of a fault on the line. After the fuse operates, the circuit is opened, and the line is de-energized. Because of the obvious wildfire risk associated with such an operation, comparable devices were developed to eliminate the sparks expelled to the ground. In essence, energy is still redirected through a charge; but the charge is blown into a bed of sand that is fully enclosed in the equipment itself. Thus, this new type of fuse has earned the name of “non-expulsion fuse,” because it does not expel sparks towards the ground. A non-expulsion fuse offers undeniable wildfire mitigation benefits compared to an expulsion fuse. The only downside is cost, because a non-expulsion fuse costs many more times as much as a standard expulsion fuse. Because it effectively eliminates a definite risk of ignition, the company has determined that non-expulsion fuses are a cost justified wildfire mitigation strategy in the FHCA. Similarly, expulsion lightning arresters when exposed to an overvoltage condition, typically caused by lightning, will ignite a small charge that could expel a spark towards the ground. The company is in the process of replacing these devices with non-expulsion equivalents.

Fuse replacement also implicates coordination concerns. To enable effective trouble-shooting, fuses on downstream sections of a line need to be fuse coordinated with upstream devices. As a result, an individual expulsion fuse cannot simply be replaced with a non-expulsion device in isolation. Recognizing fuse coordination concerns, Rocky Mountain Power is planning to complete fuse replacements on a line-by-line basis. Because the FHCA is a geographic area, some sections of a line can be in the FHCA while other sections of the same line are not. For purposes of fuse coordination, the company will fuse coordinate all downstream sections of a line with any portion of such line in the FHCA.

8. New Construction

As demonstrated throughout this wildland fire protection plan, most wildland fire protection strategies focus on existing facilities. The electric system is not, however, static. As communities face growing risks of wildfire, electric utilities need to also consider mitigation strategies that address new and modified facilities. Indeed, the wildfire risk is driven largely by human development. While significant wildfires in remote wilderness areas are serious events with both positive and negative ecological consequences, the wildfires that cause the greatest harm to people and property are those that occur nearer to denser areas of human development. Above all, as discussed in the risk assessment section above, human development in the wildland urban interface – the area in which homes and other development are situated near expanses of predominantly wildland vegetation or incorporate sections of wildland vegetation in their landscaping plans – is particularly susceptible to wildfire. The relatively dense populations and relatively expensive structures in these wildland-urban interface areas pose a unique wildfire risk. And the electrical network plays a role, because the electrical network follows and facilitates the growth and expansion of new buildings where people live and work. From a wildfire perspective, the popularity of underground facilities, driven mostly by aesthetic concerns, significantly mitigates the wildfire risk associated with electric service (despite also increasing some maintenance and reliability concerns). At the same time, underground facilities tend to be much more expensive than traditional overhead construction. In any case, serving load growth in and around the wildland urban interface should factor in a comprehensive wildfire mitigation strategy.

The system of electrical facilities owned and operated by Rocky Mountain Power can be expanded in multiple ways. New construction on the transmission network is typically planned, designed and constructed by Rocky Mountain Power from initiation to end of any project. With respect to distribution lines, expansion of the electrical network is typically driven by customer demand. In general, these expansions are commonly referred to as “line extensions,” because power lines are constructed to extend service to a new location, based on the application made by an applicant.

8.1. Line Extensions

Electric Service Regulation No. 12 govern the process by which line extensions are made. The obligation to serve all customers, on fair terms, is a core principle for regulated electric utilities and is embedded in Regulation No. 12. Along these lines, any wildfire mitigation strategy must be consistent with those rules and regulations.

Right-of-Way – Route Selection. Consistent with Regulation 12 Section (1)(m), Rocky Mountain Power selects the route for a proposed Line Extension. Rocky Mountain Power has to consider a number of factors in selecting the optimal route. The factors include physical construction constraints in topography or soil type, physical access for both construction and long-term maintenance, obtaining the lowest cost to the applicant, and efficiency considerations related to future connections. In some cases, the optimal path is clear. Not surprisingly, following the path of an existing road can often be a sensible approach. In other cases, the optimal path may be less than clear. In some situations, the applicant may have other priorities that support a particular path. In consideration of the underlying principle to provide service on fair terms and the goal of providing excellent customer service, customer preference is factored in the analysis, including a desire to accomplish the lowest cost alternative for the customer.

Another factor in choosing the route for a line extension is the practical need to obtain the necessary legal entitlements for the right-of-way. Under Regulation 12 Section (1)(m), the applicant is responsible for providing Rocky Mountain Power with standard easement rights sufficient to construct and maintain the new facilities. In some situations, the applicant will need to obtain easement rights from a neighboring landowner. This reality will often implicate a need for Rocky Mountain Power to cooperate with the customer on selecting a secondary route alternative, if the applicant is unable, after reasonable efforts, to obtain the easement rights necessary for the preferred path. In those circumstances, Rocky Mountain Power will work with the applicant to identify a secondary route, if feasible, to enable completion of the line extension.

In all cases, an estimator considers local, site-specific conditions. To mitigate the wildfire risk associated with new construction, Rocky Mountain Power estimators will be factoring greater weight on the wildfire risk in selecting the preferred route for a line extension. Because of the impact of fuels, this factor is given more weight in areas with wildland vegetation. To this end, estimators are encouraged to favor routes that have good access, which is valuable not only for regular maintenance but also for spotting and suppressing a fire. Estimators are also encouraged to favor routes that traverse areas with less wildland vegetation (e.g., irrigated areas). All other factors must still be considered, including the total end cost to the customer. The mitigation goal is to make wildfire risk an issue that is properly factored into the route selection process, especially in areas of greater relative risk. Rocky Mountain Power estimators are encouraged to be aware of the wildfire risk associated with any particular route, especially when designing new construction in the FHCA.

Right-of-Way – Pre-Construction Clearing. Again under Regulation 12 Section (1)(m), the applicant is required to make the right-of-way ready for construction. In addition to any costs associated with obtaining the necessary easements, there are some construction costs related to physically preparing the right-of-way for installation. For example, if a right-of-way has to be graded to allow vehicle access, such a cost is appropriately borne by the applicant. If a tree has to be removed to clear way for the installation of a pole, the cost to remove the tree is appropriately charged to the applicant. Likewise, any trees that would immediately implicate the minimum clearance specifications set by Rocky Mountain Power vegetation management must be pruned or removed before construction. Thorough and effective pre-construction clearing significantly aids the efforts of Rocky Mountain Power vegetation management in maintaining clearances through subsequent cycles. Furthermore, any high risk trees that could fall and strike the new line should be evaluated for removal before any construction. Estimators are encouraged to coordinate with vegetation management and to strictly enforce existing requirements for making the right-of-way ready for construction.

Rocky Mountain Power continues to consider how the existing requirements to ready the right-of-way might be further engaged to promote wildfire mitigation. In areas of elevated wildfire risk, preparing a right-of-way to be more resilient to the wildfire risk is arguably part of "preparation or clearing of land." for example, trees that will grow to violate clearance specifications could be removed as part of pre-construction clearing, even if they do not implicate minimum clearance specifications at the time of construction. In addition, trees that are tall enough, or will grow tall enough, to fall and strike the line should be removed. These more aggressive tactics may not be appropriate for every line extension; estimators, in consultation with company foresters, will evaluate such options on a case by case basis.

Facility Design – FHCA Exempt Design Standards. The use of FHCA Exempt equipment is required on line extensions in the FHCA. (See the construction standards section above.) Such requirements may include the use of covered conductor. There is, however, a potential exception for the use of non-expulsion fuses that have an FHCA Exempt design standard. It is necessary to maintain downstream fuse coordination on any power line. Estimators will only use FHCA Exempt fuses on the circuits that have been coordinated with FHCA Exempt fuses. If a circuit has not been coordinated with FHCA Exempt fuses, estimators will use normal T-fuses.

When a line extension is completed in an area of heightened wildfire risk, the facilities should be designed to minimize the risk of ignition. Because of the wildfire risk, the company is making many investments in wildfire mitigation programs that involve replacing working equipment. Completing the initial construction with FHCA Exempt equipment removes any future need to replace such equipment as part of a costly after-the-fact mitigation program. While use of FHCA Exempt equipment is required only in the FHCA, estimators are encouraged to use FHCA Exempt equipment outside the FHCA if local site conditions (i.e. dense wildland vegetation) warrant such use. (Again, it is necessary to maintain proper fuse coordination, so any use of FHCA Exempt fuses will likely be used in conjunction with circuits on the border of the FHCA or on spurs serving a remote location in a wildland area, such as a tap line serving a remote, wooded canyon.)

Facility Design – Span Width. New construction on distribution lines in the FHCA will require urban ruling span. Greater span lengths between poles can reduce construction costs. But shorter span lengths decrease the potential for excessive sag and sway, which can result in phase-to-phase faults on a line. Phase-to-phase faults can result in arcing, which could potentially lead to a fire ignition. Construction using urban ruling span results in substantially shorter span lengths compared to rural ruling span. Traditionally, many areas of elevated wildfire risk would qualify as "rural," and so greater span lengths have been approved in such areas. In areas of the greatest wildfire risk, however, Rocky Mountain Power has determined that the extra construction cost to decrease span lengths is warranted. Accordingly, Rocky Mountain Power is reducing the span lengths between poles in the FHCA by requiring the use of urban ruling span. In addition, estimators consider using urban ruling span on new construction outside the FHCA, when local site conditions indicate an elevated wildfire risk on the particular route selected for the new distribution line.

Facility Design – Underground Construction. The basic design decision of whether to use standard bare overhead wire, some variant of covered conductor, or underground construction has significant implications, for both construction cost to the applicant and long-term wildfire mitigation for the utility. Unless a local ordinance requires underground construction, a line extension traditionally used a bare conductor overhead design. If the applicant is willing to pay the additional cost for an underground construction, an applicant may request underground installation. In certain circumstances, underground design may be required, and estimators consider the benefits of underground installation in areas with wildland vegetation. Because of the dramatic increase in cost, however, an applicant is not typically required to pay for underground construction. Consistent with the other treatments in wildland areas, it is more common to require use of covered conductor and other FHCA exempt equipment in areas of elevated wildland fire risk. Rocky Mountain Power will continue to consider whether more frequent use of underground installation is warranted in rural, wildland areas.

9. Situational Awareness

Situational awareness involves knowledge of the conditions that impact the potential for wildfire ignition and spread. Increasing its situational awareness of such conditions helps an electric utility respond to local conditions and minimize the wildfire risk by making mitigation strategies more effective.

Rocky Mountain Power obtains data regarding local conditions from many sources and uses the data to adjust its operations. Local weather data is the main input. For example, as discussed above, Rocky Mountain Power will adjust reclosing operations based on fire weather forecasts published by government agencies. Above all, the program for de-energizing a power lines, discussed below, is heavily dependent on situational awareness.

Weather Consultants. To improve its access to localized fire weather forecasts, the company has engaged an external weather forecasting expert, Western Weather, to provide Rocky Mountain with daily forecasts for key areas in the FHCA. As discussed in greater detail below, Western Weather may also be called upon to provide real-time weather consulting. Rocky Mountain Power has also engaged experts in the Department of Atmospheric Sciences at the University of Utah to better understand weather metrics associated with wildfire risk, specifically in context with Utah's climate.

Weather Stations. Rocky Mountain Power continues to evaluate the need for additional micro weather data in areas with a high risk of wildfires that could threaten the public and property. In 2019, Rocky Mountain Power installed 11 weather stations on transmission and distribution assets. The company plans to install 25 additional weather stations, to obtain more precise local weather data in the FHCA and Public Safety Power Shutoff (PSPS) areas outlined in Section 10.3. Among other applications, the weather data is used to help determine when to implement an Emergency Operation Center.

High-Definition Cameras. While prevention is always the best mitigation, Rocky Mountain Power is also exploring the effectiveness of high-definition cameras in helping suppress wildfires before they get out of control. Rocky Mountain Power is partnering with Alert Wildfire Systems to install 14 cameras on existing wireless broadband towers. The primary purpose for installing cameras on the Alert Wildfire network is to detect a new plume of smoke at the earliest time possible, to facilitate rapid and effective suppression responses by the appropriate suppression agencies. This technology reflects great potential for minimizing the impact of an ignition, especially in remote areas where a wildfire can often grow out of control before being spotted by people. Cameras at each location will be evaluated after three years of installation to determine whether their locations are proved to be beneficial.

Community Engagement. In understanding wildfire and wildfire risk, Rocky Mountain Power gathers information from community resources. During periods of elevated wildfire conditions and when a wildfire is in progress, the company collaborates with emergency response professionals and local government to help evaluate when and if a power should be de-energized because of an approaching wildfire. Along those lines, the company works with fire suppression experts to protect the electrical network critical infrastructure. Recognizing the long-term benefits of preventative measures, Rocky Mountain Power is committed to supporting programs which decrease the risk of wildfire and/or the impact of wildfire. For example, the company supports educating the public on maintaining defensible space. These common sense measures can both prevent fires and minimize the harm of fires. Defensible space requirements typically address vegetation clearances around power lines, including end of the line service drops to a customer. Compliance with such provisions can help prevent a falling tree branch from bringing down an energized wire. In addition, defensible space works to protect valuable structures from catching fire and burning, thereby minimizing the impact of a wildfire moving through the area. Finally, as discussed in the next section, community engagement is a major focus in Rocky Mountain Power's plan for proactive de-energization.

10. Public Safety Power Shutoff (PSPS)

10.1. Methodology

Rocky Mountain Power may de-energize power lines as a preventative measure during periods of the most extreme wildfire risk. This strategy is sometimes referred to in the industry as "proactive de-energization" – Rocky Mountain Power's initiative is specifically referred to as "Public Safety Power Shutoff" or "PSPS." Traditionally, power lines may be de-energized when an active wildfire is threatening a line. Proactive de-energization implicates a different scenario, contemplating de-energization of lines before there is any fire. The decision to employ PSPS is based on extreme weather conditions, including high wind speeds, high temperatures, low humidity and low fuel moisture content. In essence, PSPS is intended to avoid the potential of an ignition at a time in which such an ignition would be most dangerous. PSPS is a wildfire mitigation strategy of last resort, used to supplement – not replace – all of the various mitigation strategies discussed above. Rocky Mountain Power plans to implement PSPS in only exceptional circumstances. Not only is de-energization inconvenient to customers, de-energization also potentially implicates other public safety concerns. While Rocky Mountain Power cannot guarantee a constant supply of power – and all customers are responsible to make sure that they have backup, contingency plans for when the electric grid is down – Rocky Mountain Power recognizes the practical reality that a reliable energy grid supports a community's ability to respond to a wildfire (i.e., telecommunications, streetlights, water systems, etc.). In balancing these concerns, Rocky Mountain Power makes extraordinary effort to keep the entire grid energized at all times, and PSPS is implemented only when high winds threaten to damage equipment and spark a fire during the most extreme fire conditions.

In 2019, Rocky Mountain Power developed a PSPS plan for Utah. During the summer of 2019, the company met with representatives of local government and the emergency response sector in each of the potentially affected communities to explain the PSPS plan. In addition, Rocky Mountain Power notified customers and held open town hall workshops. Fortunately, due to the relatively mild fire conditions in 2019, Rocky Mountain Power did not have to implement an actual PSPS event. For 2020 and beyond, the company is further evaluating the strengths and weaknesses in the PSPS plan and will make updates and revisions accordingly. In particular, as discussed in the situational awareness section above, Rocky Mountain Power engaged experts in the University of Utah's Department of Atmospheric Sciences, primarily to improve the company's understanding of wildfire weather conditions specific to Utah's climate. Based on that engagement, and additional input from other experts, Rocky Mountain Power expects to further refine the processes it uses to make the ultimate decision of whether to implement a PSPS.

10.2. Methodology for Selecting PSPS Areas

PSPS will only be implemented in geographic areas of the highest wildfire risk. As discussed in the risk assessment section above, Rocky Mountain Power identified Fire High Consequence Areas (FHCA) in its Utah service territory, reflecting areas of elevated wildfire risk. To develop its PSPS plan, Rocky Mountain Power further examined the FHCA, identifying areas of extreme risk due to wildfire to people and property, including where constraints on ingress and egress pose special concerns. Rocky Mountain Power also considered the impact of other wildfire mitigation strategies, discussed throughout this plan, and their effectiveness in eliminating the risk of utility related ignition. As a result of this combined analysis, Rocky Mountain Power identified 10 geographic areas within the FHCA that may be subject to PSPS because of the heightened risk of catastrophic wildfire. Because of population density, nine areas are clustered in the Wasatch Mountains east of Salt Lake City. In such areas, when electrically connected power lines were included, there were over 23,000 customers potentially impacted by a PSPS. Rocky Mountain Power explored alternatives to minimize the impact of a PSPS on such customers. To this end, the company investigated engineering solutions to isolate portions of power lines that reflect substantially less risk of utility-related ignition of a wildfire, meaning that those sections may not need to be de-energized during a PSPS event. For example, if a section of a circuit primarily consists of underground electrical facilities, engineers reviewed whether those underground facilities could be isolated and kept energized during a PSPS. Likewise, if a portion of a circuit was in a high-risk FHCA, but another portion of the circuit was in a relatively low-risk area (i.e., a highly developed area with impervious surfaces and irrigated landscaping), engineers again reviewed whether those lower-risk areas could be isolated and kept in service during a PSPS event. Through this detailed engineering review, Rocky Mountain Power was able to identify substantial sections of the impacted distribution circuits that could be isolated and kept energized during a PSPS event. When the engineering review was done, isolation solutions reduced the impacted customers to approximately 5,700 customers remaining in the resulting PSPS areas, reflecting a greater than 75% reduction.

10.3. Description of PSPS Areas

There is an interactive map on Rocky Mountain Power's website showing the boundaries of the PSPS areas, available on the Public Safety Power Shutoff page at https://www.rockymountainpower.net/outages-safety/wildfire-safety/public-safety-power-shutoff.html. Depending on specific real-time fire weather conditions, such boundaries could shift. For planning purposes, however, any PSPS event would very likely be constrained to the specific area depicted in the interactive map. Such areas are also shown in the figures below.

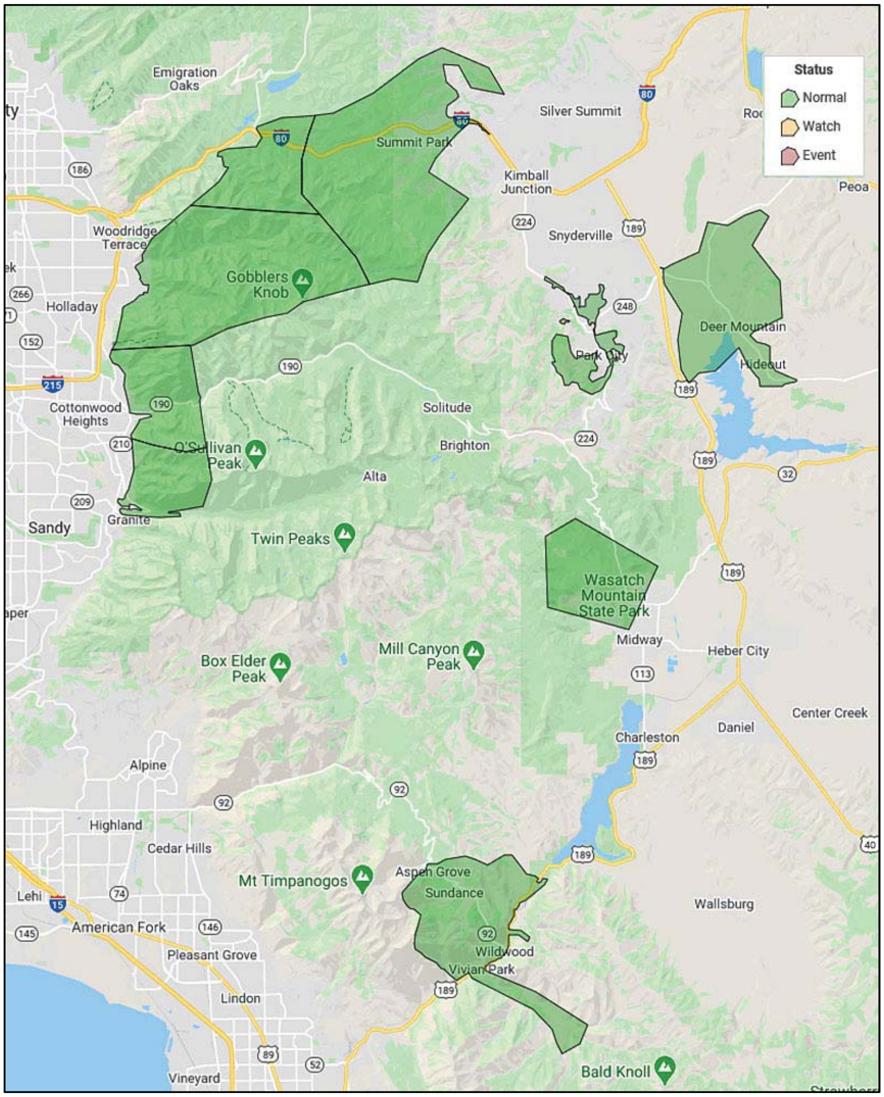

Figure 26. Map of Public Safety Power Shutoff Area in Northern Utah

Little Cottonwood. The Little Cottonwood PSPS focuses on the overhead lines at or near the mouth of Little Cottonwood Canyon.

Figure 27. Map of Little Cottonwood Canyon Public Safety Power Shutoff Area

Big Cottonwood. Similarly, the Big Cottonwood PSPS focuses on the overhead lines at or near the mouth of Big Cottonwood Canyon.

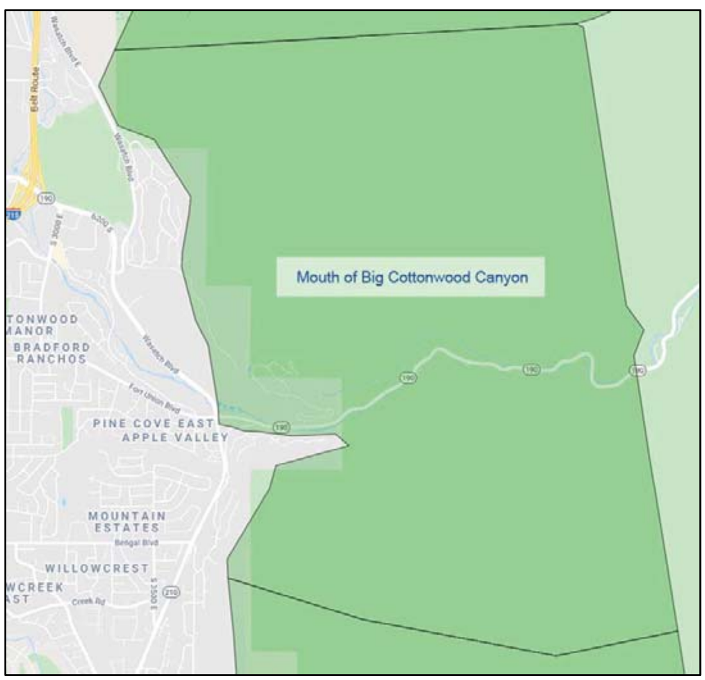

Figure 28. Map of Mouth of Big Cottonwood Canyon Public Safety Power Shutoff Area

Olympus Cove and Millcreek Canyon. This PSPS area includes the properties on the furthest east portions of Olympus Cove that are nearest the wildland areas in the foothills and the entirety of Millcreek Canyon.

Figure 29. Map of Olympus Cove and Millcreek Canyon Public Safety Power Shutoff Area

Mountain Dell. The Mountain Dell PSPS includes the section of the overhead distribution circuit headed east, up Parley's Canyon, from the company's Mountain Dell substation and the overhead distribution line serving the Mt. Aire neighborhood.

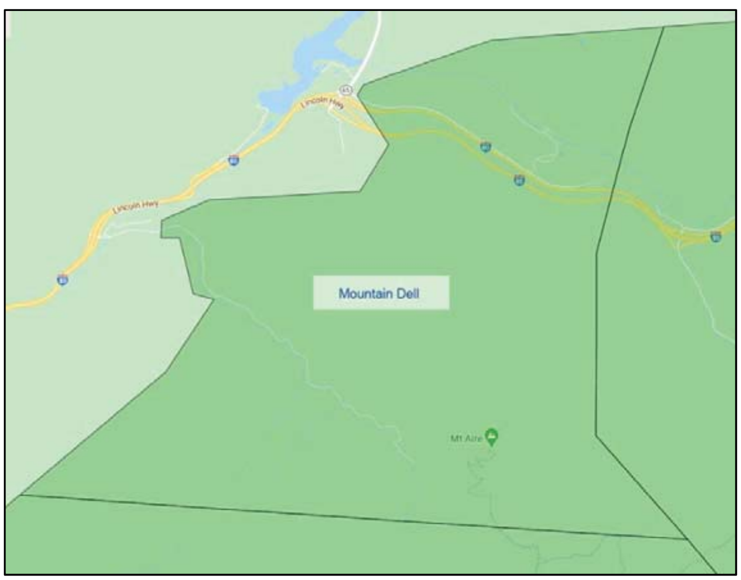

Figure 30. Map of Mountain Dell Public Safety Power Shutoff Area

Summit Park. The Summit Park PSPS includes all of Summit Park, Lamb's Canyon, and the western portion of Jeremy Ranch.

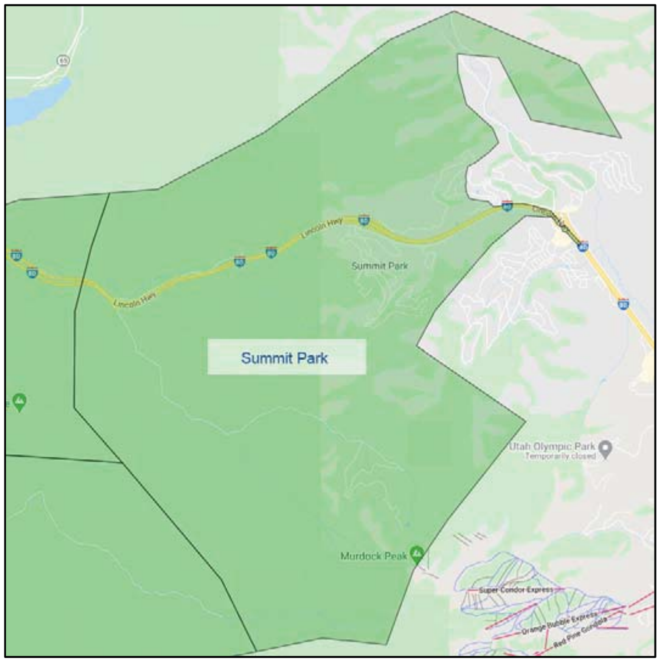

Figure 31. Map of Summit Park Public Safety Power Shutoff Area

Park City. The Park City PSPS focuses on overhead sections of line around Park City. Some underground was included because it could not be isolated. Historic downtown was excluded (and would thus remain energized during a PSPS) because of the prevalence of imperious and irrigated surfaces.

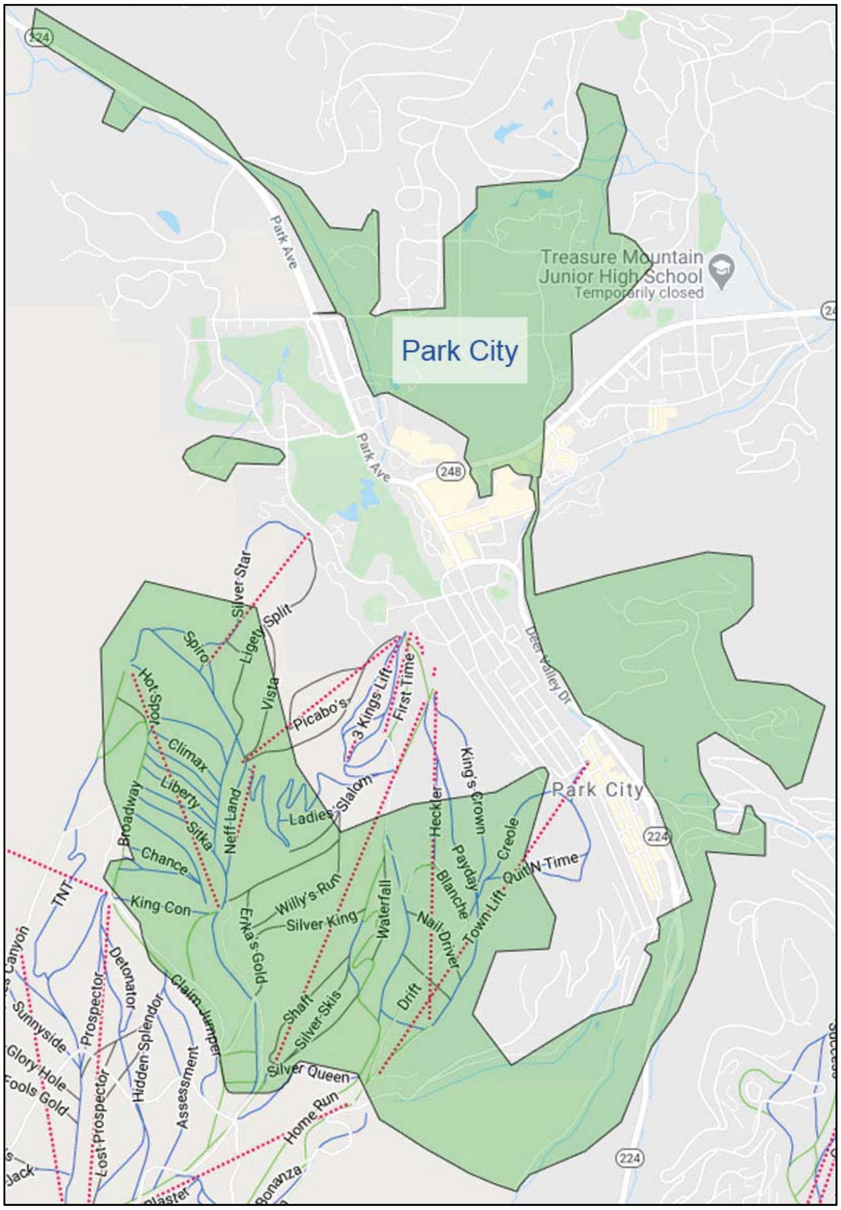

Figure 32. Park City Public Safety Power Shutoff Area

Jordanelle North Shore. The Jordanelle North Shore PSPS includes the entire area north of Jordanelle Reservoir.

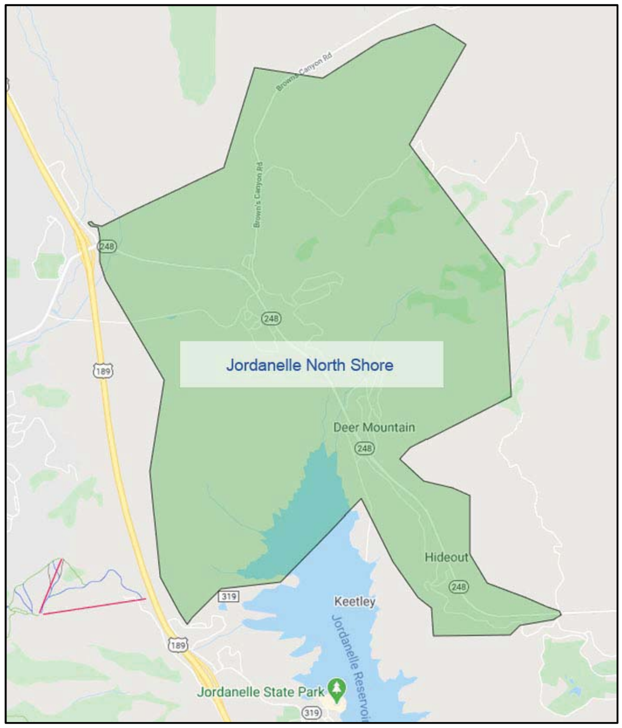

Figure 33. Map of Jordanelle North Shore Public Safety Power Shutoff Area

Wasatch Mountain State Park. The Wasatch Mountain State Park PSPS is the distribution line serving the campground in the Wasatch Mountain State Park and the properties on Snake Creek Road.

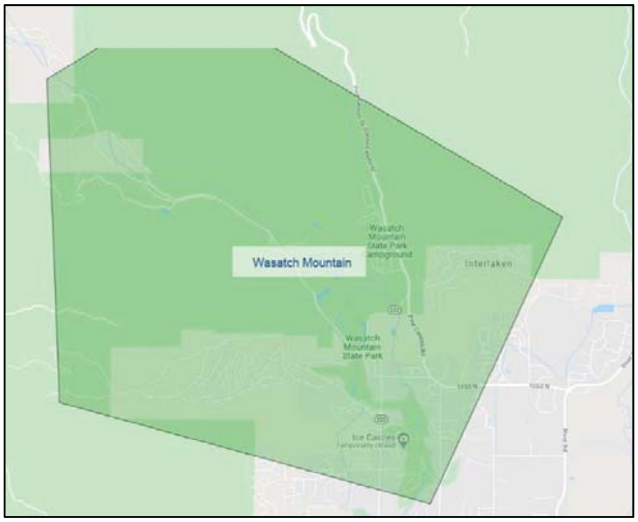

Figure 34. Map of Wasatch Mountain Public Safety Power Shutoff Area

Wallsburg / Sundance. The Wallsburg / Sundance PSPS includes Sundance and the properties east of Provo Canyon up South Fork Road served from the Wallsburg substation.

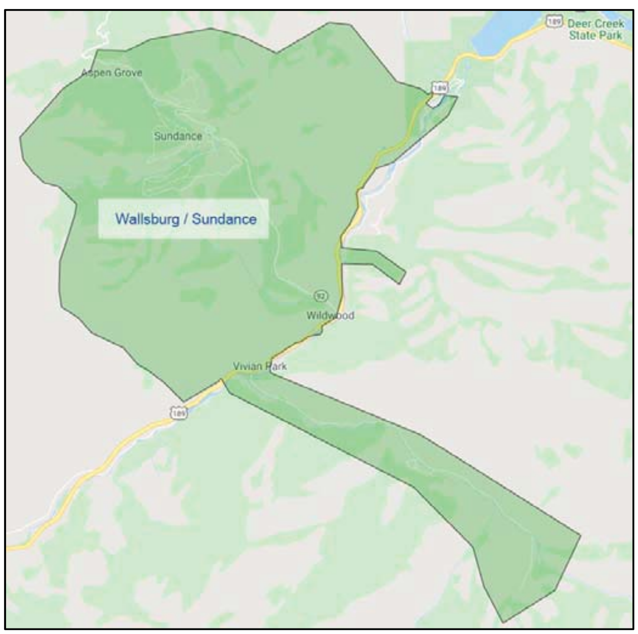

Figure 35. Map of Wallsburg / Sundance Public Safety Power Shutoff Area

Cedar City. The Cedar City PSPS is focused on overhead lines serving subdivisions southwest and southeast of historic Cedar City that are part of the wildland-urban interface.

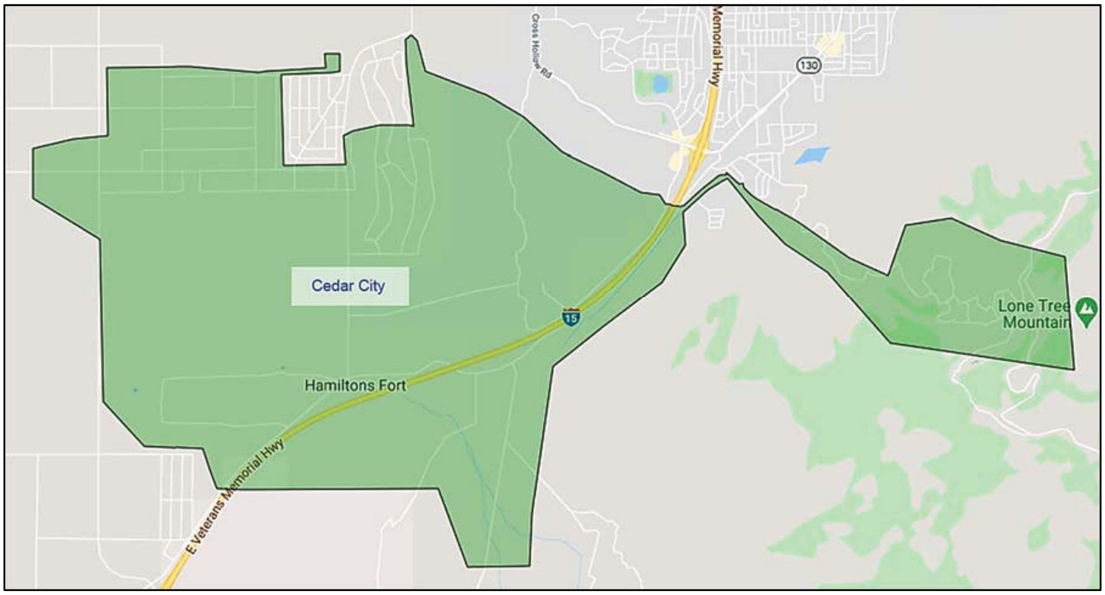

Figure 36. Map of Cedar City Public Safety Power Shutoff Area

10.4. Implementation Protocols

As discussed in the situation awareness section, Rocky Mountain Power engaged a meteorological consultant to perform weather monitoring and forecast services, focusing on the PSPS areas. Every day during fire season, the weather consultant provides a forecast report on each of the PSPS areas. Such forecasts may prompt a notification to customers in a PSPS area of a potential PSPS event. Because weather forecasts are, by nature, inherently speculative, it must be stressed that such notifications only alert customers of the potential of a PSPS event. In 2019, Rocky Mountain Power employed a set of objective criteria to determine whether a notification was warranted. In 2020, the company engaged experts in the Department of Atmospheric Sciences at the University of Utah to assist in refining the metrics that would indicate that a notification is warranted. Rocky Mountain Powers expects that this will be a somewhat iterative process, as the company seeks to find a balance between adequately warning the public of a potential PSPS event versus raising a false alarm too frequently.

After the first notification is delivered, Rocky Mountain Power actively monitors actual weather conditions and endeavors to provide customers with additional notifications. If extreme wildfire conditions are forecast (or measured in actual conditions), Rocky Mountain Power may activate its Emergency Operation Center (EOC), which will closely monitor the electrical network and the weather, in consultation with the expert meteorological consultant. To this end, the EOC may deploy circuit crews in the subject PSPS area, to monitor local environmental and asset conditions on the ground and in real time. The circuit crew lead will have direct communication channels to the EOC. Upon activation of the EOC, the company assembles customer lists in the subject PSPS area and a communication plan for those customers. The EOC is staffed to fill the following primary roles:

Table 14. PSPS Emergency Operations Roles

PSPS Emergency Operations Center Leads				Backup		
All Hazards / PSPS	**LastName**	**FirstName**	**Primary**	**Order**	**LastName**	**FirstName**
All Hazards / PSPS	Mansfield	Curt	Emergency Operations Center Director	2	Ralston	Dana
				3	Bennion	Doug
All Hazards / PSPS	Rich	Bret	Safety Officer	2	Nicholes	Todd
				3	Fewkes	Royce
All Hazards / PSPS	Freestone	Kevin	Operations Section Chief	2	Spencer	Chris
				3	Fryer	Colby
				4	Bodily	Dan
All Hazards / PSPS	Skinner	Wade	Liaison Officer	2	Miyake	Kristyn
				3	Connors-Perez	Teresa
All Hazards / PSPS	Anderton	Steve	Logistics / Resource Section Chief	2	Chapman	Jr.
				3	Stoor	Marv
All Hazards / PSPS	Comeau	Bill	Regional Business Manager Section Chief	2	Morse	Lucky
				3	Area Regional Business Manager	
All Hazards / PSPS	On-Call		Public Information Officer		Eskelsen	Dave
					Erickson	Tiffany
					Hall	Spencer
All Hazards / PSPS	Favero	Kerry	Vegetation Management Section Chief	2	Evans	Dylan
				3	Vanderhoof	Robert
All Hazards / PSPS	Liguouri	Sherry	Environmental Section Chief	2	Norton	Aaron
				3	Edmisten	Scott
All Hazards / PSPS	Earl	Sheri	Emergency Operations Center Support	2	Owen	Jennifer
PSPS	Vickers	Jeff	PSPS Weather Coordinator	2	Johnson	Matt
				3	Attaway	Robin
				4	Wells	Chris
PSPS	Cavazos	Kellan	PSPS Transmission Coordinator	2	Wilson	Nathan
				3	Baye	Dan
				4	Riet	Chris
PSPS	Oakeson	Brian	PSPS Distribution Coordinator	2	Turner	TJ
				3	Squires	Blair
PSPS	Jones	Josh	PSPS Asset Conditions Coordinator	2	Bryson	Chris
				3	Golo	TJ
				4	Moulton	Jon
PSPS	Christofferson	Cindy	PSPS Circuit Crew Coordinator Summit County / Park City	2	Hermreck	Jeff
				3	Lester	Dustin
				4	Martinez	Julene
PSPS	Hermreck	Jeff	PSPS Circuit Crew Coordinator Salt Lake / Wasatch County	2	Lester	Dustin
				3	Martinez	Julene
				4	Rayburn	Ron
PSPS	Lindley	Jeff	PSPS Circuit Crew Coordinator Utah County	2	Staheli	Kevin
				3	Walker	Lance
				4	Ferre	Adam
PSPS	Perschon	Chris	PSPS Circuit Crew Coordinator Iron County / Cedar City	2	Buelte	Rich
				3	Hoggard	Lonnie

Each specific EOC role has a primary person assigned to be responsible for that role, and each primary person has three designated backups.

Based on all of the information available to the EOC, the EOC director may make a decision to implement a PSPS. Consistent with existing regulations and the general mandate to operate the electrical system safely, the EOC has discretion to determine when a PSPS is appropriate or not, at any particular time. In general, barring other unique circumstances, a PSPS would not be implemented unless extreme wildfire conditions have been measured (versus forecast only).

The EOC director will consider all available information, including real-time feedback from other EOC participants and the circuit crew lead in the field, to determine whether PSPS is appropriate. In addition, based on all available information, the EOC director may decide to further refine the PSPS areas described above. As a matter of practical reality, the EOC director cannot know whether a PSPS will prevent a utility-related ignition or not. If a PSPS is not implemented and an ignition occurs, the ignition itself is not proof that a PSPS should have been implemented. Likewise, if a PSPS is implemented, the event itself does not prove that an ignition that would have otherwise occurred was prevented. If the decision to implement a PSPS event is made by the EOC director, the de-energization and restoration is governed by system operating procedures designed for this purpose. Those procedures include a detailed procedure to patrol and visually inspect the entire circuit prior to re-energizing.

10.5. Communication Plan

When there is a potential PSPS event forecast, customers and local government representatives will be provided notice, if feasible. The goal is to begin notifying customers 48 hours in advance of a potential de-energization event. If this is not possible due to rapidly changing weather conditions (or any other emerging circumstances), the notification process will begin as soon as possible. Additional notice will be provided at appropriate times, as conditions are monitored and depending on the circumstances. There is some degree of balancing required. Customers generally want ample advance notice of any actual de-energization. At the same time, recognizing that weather forecasts are inherently speculative, it is possible to overburden customers with notices of “potential” PSPS events that never materialize, especially remembering that Rocky Mountain Power’s fundamental business objective is to keep the grid energized except under the most extreme conditions. Rocky Mountain Power seeks to maintain balance by making information available through multiple outlets.

In sending notices to customers, Rocky Mountain Power seeks to provide customers regular status updates about any PSPS event. In addition to basic information regarding anticipated times of de-energization or re-energization The company will provide information, which may include the following: (a) actions being taken to reduce the need to implement PSPS; (b) updates on actual and forecast weather conditions; (c) criteria being monitored as part of the PSPS evaluation; (d) maps of impacted areas; and (e) restoration information.

Rocky Mountain Power’s communication plan contemplates notices to customers using multiple methods of communication. Direct customer notifications will be a combination of outbound calls, texts and emails. All customers will receive an outbound call at the one-hour mark, the beginning of the event, the beginning of the re-energization, and the cancellation of the event. Other notifications may be made leading up to during an event, at the instruction of the EOC director during the event. The company Rocky Mountain Power may post more frequent updates, leading up and during an event, on its website[14] and through social media. Certain representatives of local government and other community-based organizations are contacted directly by company personnel who are responsible for those relationships.

Additional procedural precautions are taken to make sure that notice of a PSPS is provided to customers with a serious medical condition who depend on electric service for necessary treatment. After an EOC is activated and before a PSPS event, Rocky Mountain Power will attempt, time and circumstances allowing, to make personal contact with vulnerable customers using life support equipment.

10.6. PSPS Mitigation Activities

Rocky Mountain Power is sensitive to the ramifications of a PSPS. Turning off the power is contrary to an electric utility's core mission and culture. And Rocky Mountain Power understands that turning off power can have negative consequences for customers and the public at large. Concerns range from the economic impact that loss of power can mean to business customers, to the inconvenience for residential customers, to the serious implications in loss of power to certain medically vulnerable populations, who might depend on electric power for life-saving equipment. De-energization can also have an impact on public safety. Many irrigation systems depend on electric power. Communications systems can be impacted. Loss of traffic lights can slow down an evacuation. If a loss of power persist, community water and sewer systems are at risk. For all of these reasons, PSPS is the strategy of last resort. In keeping safety as its top priority, however, Rocky Mountain Power may have to implement a PSPS to guard against being a source of ignition. In doing so, the company has also planned certain measures to minimize the impact of such an event.

First, Rocky Mountain Power proactively worked to limit the breadth of a PSPS long before an actual event by be required. As discussed above, the company performed an engineering review to limit, as much as possible, de-energization to those power lines most at risk, being overhead lines in high-risk wildland areas. To facilitate the process, the company has invested in certain protection equipment which allowed the desired isolation of at-risk segments of a circuit.

Second, Rocky Mountain Power included in the PSPS plan measures to notify medically vulnerable populations. Customers who are currently identified as medical baseline for purposes of Electric Service Regulation No. 10 Section 2(c) (Serious Illness) and Section 2(d) (Life Support Equipment) are automatically be treated as vulnerable customers to receive special PSPS notices for medically vulnerable customers. Rocky Mountain Power also provides customers the opportunity to self-identify as a member of a vulnerable population, and the company completed outreach to vulnerable customers through direct mail, town hall-style meetings, social media, and the company's website. In conjunction with this outreach effort,

[14] See https://www.rockymountainpower.net/outages-safety/wildfire-safety/public-safety-power-shutoff.html.

the company engaged with community organizations which serve vulnerable populations to assist in the outreach.

Third, Rocky Mountain Power may deploy mobile generation to help mitigate any impact of a PSPS. Based on local and real-time circumstances, the EOC will decide if deployment is warranted and in what manner deployment would be most effective.

11. Emergency Management and Response

11.1. General Description

Rocky Mountain Power's emergency response to a wildfire is guided by the same principles and procedures that govern Rocky Mountain Power's response to other types of incidents. Whenever electric service is disrupted (or a disruption is threatened), Rocky Mountain Power's emergency response is guided by the National Incident Management System. This basic approach is applicable with respect to any type of wildfire event, ranging from a relatively small wildfire that a local fire suppression agency is able to control, to the larger wildfire events that require a coordinated interagency response. There is, of course, some variation in response driven by the specific characteristics of the event. For example, the governmental emergency responders with whom Rocky Mountain Power will coordinate will be different in a wildfire as compared to other types of events. For small wildfires, Rocky Mountain Power personnel will likely work directly with local firefighters; for larger wildfires, Rocky Mountain Power management will likely coordinate with an incident command center that could involve representatives of both state and federal agencies, likely including the BLM or the National Forest Service. In general, however, Rocky Mountain Power's internal response structure will be organized for a wildfire event in a manner substantially identical to any other incident requiring an emergency response.

The National Incident Management System (NIMS) guides all levels of government, nongovernmental organizations(NGO) and the private sector to work together to prevent, mitigate, respond to and recover from incidents. The NIMS provides shared vocabulary, systems and processes to successfully deliver the capabilities described in the National Preparedness System. In addition, the NIMS defines operational processes, including the Incident Command System (ICS), Executive Policy Group and Emergency Operations Center (EOC) structures that guide how personnel work together during incidents. The NIMS applies to all incidents and is designed to be scalable and, therefore, applicable for incidents that vary widely in terms of hazard, geography, climate and organizational authorities.

Rocky Mountain Power's Emergency Response Plan follows the NIMS and the ICS, and it is the foundation for Rocky Mountain Power's response to all crisis and emergencies. Consequently, Rocky Mountain Power's Emergency Response Plan follows the all-hazards approach, which includes coordinating with other utilities and all levels of government. The plan supports an organized and efficient response to a wide variety of events of differing magnitudes. The all-hazard plan is a management tool providing a scalable response, organizational structure, procedures for information management, operational activities, a smooth transition to restoring normal services and the implementation of post-incident actions. Designed to be interdisciplinary and organizationally flexible, positions are determined by the event and required resources.

Executive Policy Group. The Rocky Mountain Power Executive Policy Group consists of executives and administrators from key internal organizations and is activated based on the severity of the incident and need for strategic support. As part of the structure, the group collects and analyzes information, makes high-level strategic and procedural decisions, assists in the continuation of critical business processes, and helps facilitate cross-platform incident coordination in support of those responsible for managing the incident. Concerns for public safety is a key consideration in determining the need to activate the Executive Policy Group.

Emergency Operations Center (EOC). Bringing representatives from various Rocky Mountain Power organizations together in an EOC optimizes unity of effort and enables staff to share information, provide policy guidance to on-scene personnel, plan for contingencies, deploy resources efficiently, and generally provide any support necessary. The composition of the team may vary depending on the nature and complexity of the incident.

11.2. Emergency Response / Service Restoration

Activation of the response function takes place according to the escalating threat, human impacts or severity of the incident. Incidents that threaten Rocky Mountain Power as a whole (e.g., contagious disease, cyberattacks), or place Rocky Mountain Power's stability at risk, may require high-level management to direct strategic policy, financial decision-making, crisis communications and/or other emergency management functions. During a wildfire event, Rocky Mountain Power will work in coordination with incident command to de-energize lines requested by the incident commander and to remove personnel from restricted access areas. Field personnel's first priority is to provide line work support that may include but is not limited to de-energization of power lines, inspection of assets and restoration activity. Independent fire suppression activity should not interfere with the ability to support the EOC and/or incident command. The operation of the system will be returned to normal as soon as practical, which typically occurs when the incident no longer needs the support and coordination functions provided by the EOC. If assets are damaged by the fire, the return to normal may be delayed until the facilities can be replaced or repaired. If support functions can be managed by individual organizations through normal procedures, operations may return to normal working in coordination with the EOC.

Pre-Incident Preparedness. If an event is anticipated or advanced warning is received (i.e., a winter storm warning), pre-incident activities may be implemented in advance of an actual event. Forecasts of extreme wildfire conditions may warrant pre-incident activities. These activities may include deploying additional response personnel and resources, customer and stakeholder advanced notification, and situational monitoring of wildfire conditions, such as wind speed, temperature, humidity and fuel conditions (all of which might contribute to the ignition and/or spread of a wildland fire).

Response to Incidents. The level of response is dictated by the seriousness of the incident. Incidents may be localized, or they may require support from an EOC. Moderate outage events and localized incidents require localized plan activation. In general, however, localized incidents can be quickly resolved with internal resources. These incidents have little or no impact on the public or normal operations and are managed by supervisors in the impacted district or area.

More complex outage events and potential threats that are beyond the scope of local management often require coordination of a considerable amount of resources, extended involvement and contact with internal business units and external stakeholders, and the potential for the incident to expand rapidly. This type of incident disrupts a significant number of customers, includes extended restoration time, or a perceived threat to service exists beyond the level where normal operating practices and local resources are sufficient to respond, and requires EOC activation. This type of incident might include, for example, a wildland fire, severe weather forecasts or a security threat. Additional personnel from surrounding operations districts may be required to respond.

Mutual Assistance. Electric utilities have the ability to call upon other electric companies for emergency assistance, in the form of personnel, material or equipment, to aid in maintaining or restoring electric service when such service has been disrupted by acts of the elements, sabotage or equipment malfunctions. Rocky Mountain Power is a member of several regional and national mutual assistance agreements with electric service providers. Parties to these agreements can request or provide assistance and resources to other members to support the restoration of electrical service when it cannot be restored in a timely manner by the affected Rocky Mountain Power alone.

11.3. Community Outreach / External Collaboration

Dissemination of timely, accurate, accessible and actionable information to the public is important in all phases of Rocky Mountain Power's incident management. The outage restoration call-back program is an automated system that simultaneously initiates call backs to hundreds or thousands of customers providing updated estimated times for restoration and to verify service has been restored. Communication with customers, key internal and external stakeholders and all levels of management as early as possible is key. The Rocky Mountain Power Joint Information System (JIS) consists of processes and tools to facilitate communication with the public, news organizations, government entities and external stakeholders through social media, website restoration information, press releases and notification protocols while ensuring the messaging is consistent and comprehensive.

Regional Business Managers. Rocky Mountain Power regional business managers maintain Rocky Mountain Power relationships with local government jurisdictions and community organizations. Regional business managers are the primary contact for local leadership and critical customers in their area of responsibility.

District Operations Managers. District operations managers maintain relationships and exchange contact information with local first responders. In the event of a wildland fire, district managers deploy to the jurisdictional agency's Incident Command Post (ICP) to ensure electric safety awareness. The district operations manager acts as the liaison between the ICP and Rocky Mountain Power's Control Center and EOC.

Emergency Managers. Rocky Mountain Power's emergency management group interfaces and maintains relationships with federal and state emergency responders and mutual assistance groups. The emergency manager has contact information for state, county and tribal emergency managers, the state's EOC Emergency Support Functions (ESF) personnel, and the Geographic Area Coordination Centers dispatch centers for fire-related emergency response.

Fire Cause Investigation. Rocky Mountain Power will cooperate with the wildfire incident command to review possible causes, source and origin where Rocky Mountain Power assets were damaged by a fire or when a Rocky Mountain Power asset is potentially involved in the fire origin.

11.4. Training, Exercises and Continuous Improvement

An effective response to any incident is determined by the ability to implement a controlled incident command structure and to assume responsibility for restoration and recovery activities. It is critical that individuals having responsibility for functions within the incident command system are familiar with their responsibilities and have practice performing those responsibilities. Individuals identified with primary or secondary responsibility within the command center structure complete an annual review of the overall disaster response and recovery plan. These individuals are required to contribute to post-crisis and emergency reporting, outlining any issues or concerns regarding their role and responsibilities. The incident command system is activated periodically throughout the year in the normal course of operations. An annual exercise is conducted to ensure that individuals otherwise not involved in incident management on a regular basis are practiced in responding.

Rocky Mountain Power has a goal of continuous incident management improvement. Rocky Mountain Power evaluates exercises and actual response incidents, by identifying issues raised during the exercise or incident and documenting lessons learned and corrective action plans. Multiple methods are used to gather exercise and post-action reviews, including participant and observer evaluation forms, remedial action tracking, and post-exercise or after-action incident reviews. Lessons learned may be implemented for inclusion in Rocky Mountain Power's response and restoration procedures and incorporated in the emergency response document.

12. Performance Metrics and Monitoring

Rocky Mountain Power will regularly evaluate and measure the effectiveness of the wildfire mitigation programs included in this plan. Consistent with UTAH CODE § 54-24-202, the company will file an annual report identifying the actual capital investments and expenses made in the prior calendar year and a forecast of the capital investments and expenses for the present year to implement this plan. In conjunction with preparing this report, Rocky Mountain Power intends to perform an annual assessment the plan. With respect to the wildfire risk mapping and risk assessment activities, Rocky Mountain Power will evaluate currently available data to determine whether the results and conclusions expressed in those sections remain consistent with new information. With respect to the wildfire mitigation activities identified throughout this plan, Rocky Mountain Power will evaluate whether those strategies and programs have been successfully implemented within the planned timeframes. Rocky Mountain Power also expects to learn from the review process and will update or supplement the planned mitigation activities as appropriate. A key metric for evaluating the effectiveness of mitigation strategies, especially as additional years provide additional data, will be the outages during fire season in the FHCA.

The vice president of transmission and distribution operations is the executive sponsor for this wildfire mitigation plan. The following responsible persons have been identified for specific mitigation programs.

Table 15. Rocky Mountain Power Wildfire Mitigation Plan Roles and Responsibilities

Plan Element	Responsible Role	Responsibility
Risk Mapping	Director of Asset Management	Annually evaluate new data to determine whether any modification to the risk-based mapping would be warranted.
Risk Assessment	Director of Asset Management	Annually evaluate risks and integrate new data with risk-based decision-making approach.
Inspect/Correct Programs	Director of Asset Management	Execute inspection and correction program consistent with revised inspection frequencies and correction timeframes.
System Operations	VP of System Operations	Implement system operations procedures during wildfire season and conduct annual review of performance.
Field Operations	Wires Director(s)	Implement fire season policies and arrange for the use of equipment contemplated in those policies.
Environmental	Manager of T&D Environmental	Manage Wildlife Protection Plan and evaluate effectiveness of reducing animal contacts.
System Hardening	Director of Asset Management	Administer proposed system hardening programs and evaluate the utility of adding new projects or reprioritizing planned projects.
Vegetation Management	Director of Vegetation Management	Implement annual vegetation inspections, increased minimum clearances, and pole clearing program
Situational Awareness	Director of Asset Management	Manage installation of weather stations and high-definition cameras.
Public Safety Power Shutoff	Director of Asset Management	Responsible for execution of the plan, including identification, reporting and communication

CERTIFICATE OF SERVICE

Docket No. 20-035-28

I hereby certify that on June 1, 2020, a true and correct copy of the foregoing was served by electronic mail to the following:

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Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

Rocky Mountain Power
Exhibit RMP___(CBM-2R)
Docket No. 20-035-04
Witness: Curtis B. Mansfield

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Rebuttal Testimony of Curtis B. Mansfield

Data Response OCS 11.1 - AMI In-service Dates

October 2020

OCS 11.1 (a) (c)

AMI-UT Advanced Metering Infrastructure

Actual Plant in Service addtions/balances through 06/30/2020

Part - a

WBS Description	Year/Mo	FERC Plant Account 1064000	3033250	Monthly total additions
AMI-UT - IT (Private Generation)	12/2018	1,224,263.25		1,224,263.25
AMI-UT - IT (Private Generation)	01/2019	(1,224,263.25)	1,225,345.24	1,081.99
AMI-UT - IT (Private Generation)	04/2019		244.13	244.13
AMI-UT - IT (Private Generation)	05/2019		61.03	61.03
		-	1,225,650.40	1,225,650.40

Part - c

WBS Description	Year/Mo	FERC Plant Account 1064000	3033250	Monthly total additions
AMI - Utah Energy Usage Web (EUW)	05/2020	517,354.61		517,354.61
AMI - Utah Energy Usage Web (EUW)	06/2020	6,474.26		6,474.26
		523,828.87	-	523,828.87

State	Project	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jul - Dec PPIS 2020
Distribution	AMI - Utah Meters 201	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
General Plant	AMI - Utah IT	$ 281,070	$ -	$ -	$ -	$ -	$ 1,633,451	**$ 1,914,521**
Total	**AMI - Utah**	**$ 281,070**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,633,451**	**$ 1,914,521**

State	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	PPIS 2021
Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,915,000	$ 13,972,000	$ 2,713,000	$ 4,506,000	**$ 24,106,000**
General Plant										$ 22,298,000	$ 286,000	$ 117,000	**$ 22,701,000**
Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,915,000**	**$ 36,270,000**	**$ 2,999,000**	**$ 4,623,000**	**$ 46,807,000**

Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	PPIS 2022	PPIS Overall
$ 3,568,000	$ 2,796,000	$ 3,217,000	$ 3,019,000	$ 1,378,000	$ 1,827,000	$ 1,947,000	$ 1,239,000	$ 2,468,000	$ 1,220,000	$ 1,180,000	$ 479,000	**$ 24,338,000**	**$ 48,444,000**
$ 538,000	$ 312,000	$ 290,000	$ 101,000	$ 100,000	$ 163,000	$ 150,000	$ 1,166,000	$ 83,000	$ 70,000	$ 70,000	$ 48,000	**$ 3,091,000**	**$ 27,706,521**
$ 4,106,000	**$ 3,108,000**	**$ 3,507,000**	**$ 3,120,000**	**$ 1,478,000**	**$ 1,990,000**	**$ 2,097,000**	**$ 2,405,000**	**$ 2,551,000**	**$ 1,290,000**	**$ 1,250,000**	**$ 527,000**	**$ 27,429,000**	**$ 76,150,521**

Rocky Mountain Power
Exhibit RMP___(CBM-2R) 3 of 3
Docket No. 20-035-04
Witness: Curtis B. Mansfield