PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

December 29, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: UM 2207—PacifiCorp's 2024 Wildfire Mitigation Plan

PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing with the Public Utility Commission of Oregon its 2024 Wildfire Mitigation Plan.

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

Oregon Dockets
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
Email: oregondockets@pacificorp.com

Ajay Kumar
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PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
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Additionally, PacifiCorp requests that all formal information requests regarding this matter be addressed to:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah St., Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Cathie Allen, Manager, Regulatory Affairs, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

Oregon Wildfire Mitigation Plan

2024

PACIFIC POWER

POWERING YOUR GREATNESS

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INTRODUCTION

Wildfire threats have been growing in the United States and Pacific Power has developed a comprehensive plan describing the wildfire mitigation efforts performed. The 2024 Wildfire Mitigation Plan (WMP) guides the mitigation strategies that are, or will be, deployed in Oregon. These efforts are designed to reduce the risk of utility-related wildfires, and proactively mitigate damage to Pacific Power facilities because of wildfire.

Wildfire has long been an issue of notable public concern. Electric utilities have always needed to be concerned with the potential of a fire starting because of sparks that could be emitted from an electrical facility, typically during a fault condition. The growth of wildfire size and intensity have magnified these concerns. Regardless of the causes, or political debates surrounding the issue, the reality is stark. Despite effective fire suppression agencies and increased suppression budgets, wildfires have grown 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 increased the probability and 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 typically have a direct effect on many people. A wildfire engulfing a developed area, on the other hand, can have significant consequences on people and property. For all these reasons, Pacific Power is committed to making long-term investments to reduce the risk of wildfire.

The measures in this WMP describe those investments to construct, maintain and operate electrical lines and equipment in a manner that will minimize the risk of wildfire. In evaluating which engineering, construction, and operational strategies to deploy, Pacific 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 shorten the duration 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 Oregon customers and Oregon communities, and balance costs, benefits, operational impacts, and risk mitigation in the overall imperative to provide safe, reliable, and affordable electric service.

In 2023, Pacific Power invested approximately $52.1 million in capital and $26.5 million of expense in Oregon to further many of the company's wildfire mitigation strategies, including:

- Procurement of new risk modeling tools, datasets, and software.
- Installation of 161 incremental weather stations.
- Continued implementation of increased asset inspections, enhanced asset inspections, and accelerated condition correction.
- Continued transition to a 3-year vegetation management cycle.
- Inspection of 1,700 additional miles, removal and pruning of over 12,500 additional trees (including brush equivalent), and radial clearing of over 20,000 poles.
- Scoping and initiation of design for approximately 125 miles of covered conductor.
- Rebuilt approximately 80[1] miles over overhead lines with covered conductor.
- Replacement of approximately 1,000 expulsion fuses and other expulsion equipment with non-expulsion designs.
- Upgraded 65 relays and reclosers for enhanced functionality.

1 Pacific Power successfully completed 65.5 miles of covered conductor through December 1, 2023, and, at the time of plan preparation, is forecasting completion of an additional 14.5 miles by December 31, 2023.

- Completion of public safety partner engagement and 9 PSPS planning sessions.
- Execution of 5 Oregon WMP public engagement forums.

Pacific Power's 2024 WMP incorporates the company's 2023 experience as well as feedback and recommendations from Commission staff, stakeholders, and communities. As a result, in 2024 the company is forecasting an additional investment of $975 million through 2028 (across five years), or $780 million capital and $195 million expense. Section 13, Plan Summary, Costs, and Benefits includes a summary of all plan elements, forecasted costs, and anticipated benefits.

Many of Pacific Power's wildfire mitigation efforts are focused in the defined geographic area of heightened wildfire risk. Pacific Power refers to the area as the Fire High Consequence Area (FHCA). The strategies embodied in this plan are evolving and are subject to change. As new analyses, technologies, practices, network changes, environmental influence or risks are identified, changes to address them may be incorporated into future iterations of the plan, as described in Section 12, Plan Monitoring and Implementation.

1. BASELINE RISK ANALYSIS

Pacific Power's baseline risk analysis framework consists of four main components as depicted in Figure 1 below. The framework is a cycle consisting of data collection and analysis, risk evaluation, risk treatment, and risk monitoring and evaluation.

Figure 1: Pacific Power's Baseline Risk Assessment Framework

Data Collection and Analysis provides enhanced data collection and analytics for incident tracking, trend analysis and measurement of mitigation effectiveness. This capability is discussed in the Advanced Data Analytics Tool improvements below.

Risk Evaluation includes the development of tools and models to supports location-specific risk identification to inform mitigation programs. These risk evaluation tools and models include the delineation of geographic areas of heightened risk of wildfire designated as the Fire High Consequence Area (FHCA),[2] as described and shown in Section 1.2, as well as the asset-specific risk modeling tool, FireSight, explained in Section 1.2.

Risk Treatment involves the development and implementation of mitigation programs informed by the data analysis and risk evaluation.

Finally, **Risk Monitoring and Review** supports quantitative evaluation of the effectiveness of mitigation strategies using a consistent framework and process. This work is discussed in Section 1.3, under Risk Spend Efficiency, and Sections 1.4 Annual Mitigation Selection Process, and Risk Spend Efficiency (RSE) Model Refresh. Continuous monitoring of programs is also summarized in Section 12. The framework in Figure 1 is represented as a cycle to depict a process geared to make continuous improvement. For example, data collection and analysis supports inputs to risk evaluation in a repeatable, transparent way to identify areas of risk. This in turn supports development and updates to risk evaluation tools, such as mapping of the FHCA and project prioritization tools, to inform risk mitigation programs such as vegetation management and asset inspections. Finally, risk is monitored, and programs are evaluated to enable continuous improvement.

1.1. DATA COLLECTION AND ANALYSIS

The following types of data are continuously collected, organized, and analyzed to support development of risk assessment tools and evaluation and inform Pacific Power's understanding of the wildfire risk. Additional details regarding the specific types of data collected can be found in Appendix C.

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[2] Pacific Power has identified areas of heighted risk of wildfire, which delineated geographic areas referred to as the Fire High Consequence Area or "FHCA." The geographic boundaries of the FHCA are synonymous with the boundaries of Pacific Power's designated High Fire Risk Zones (HFRZ), as that term is defined in OAR 860-024-0001. (While the geographic areas are the same, this WMP uses the term "FHCA," rather than "HFRZ," for consistency with internal usage.) See Fire High Consequence Area (FHCA) at page 32.

RISK DRIVER ANALYSIS

Pacific Power analyzes the components of risk associated with utility facilities. In particular, an understanding of risk drivers informs specific mitigation tactics or strategies that can be used to reduce the total amount of risk associated with utility operations. For example, if a risk of utility-related-wildfire exists due to the potential for equipment failure, an increase in inspections or maintenance activities might help to mitigate the risk. If a risk exists due to potential contact between power lines and third-party objects, installing conductor more resilient to contact with objects might help to mitigate that particular type of risk.

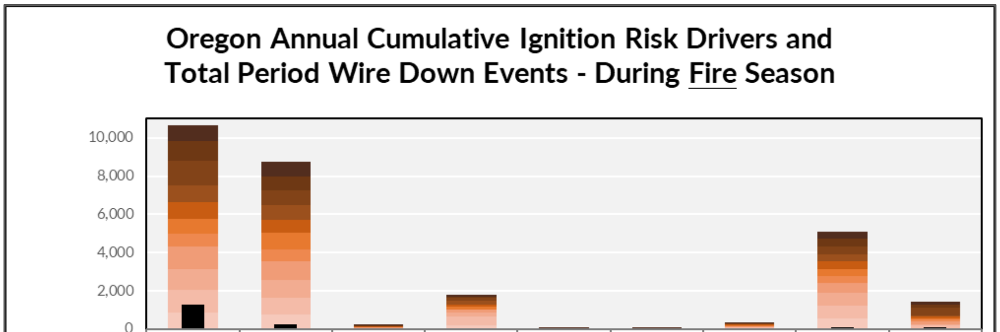
In determining the potential risk drivers, Pacific Power employs a data driven approach that references certain categories of historical outage records as a proxy for risk events. Outage data is the best available data to correlate an identifiable event on the electrical network to the risk of a utility-related-wildfire. There is a logical physical relationship: if a fault creates a spark, there is a risk of fire. An unplanned outage – which is when a line is unintentionally de-energized – is most often rooted in a fault. Accordingly, outage records were organized into categories to understand the cause of each outage with the potential for an ignition as shown in Table 1 below. The outage categories in the table align with potential correlation to an ignition.[3]

[3] These outage categories are not exactly the same as the outage classifications traditionally used for reliability reporting. For example, certain outage categories, such as loss of upstream transmission supply, planned outage, or not an outage (misclassification), do not correlate to the potential for an ignition and were excluded from the data set used for risk driver analysis.

Table 1: Outage Causes with Possible Correlation to Ignition Potential

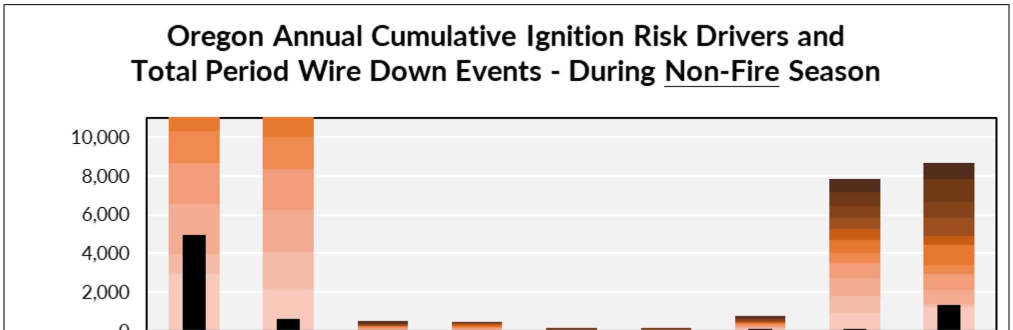
Outage Category	Risk Driver Description
Animals	Animals make unwanted direct contact with energized assets.
Environment	Exposure to environmental factors, such as contamination
Equipment Damaged	Broken equipment from car hit-poles, vandalism, or other non-lightening weather- related factors.
Equipment Failure	Failure of energized equipment due to normal deterioration and wear, such as a cross arm that has become cracked or the incorrect operation of a recloser, circuit breaker, relay, or switch
Lightning	Outage event directly caused by lightning striking either (i) energized utility assets or (ii) nearby vegetation or equipment that, as a result, contacts energized utility assets
Other External Interference	External factors not relating to damaged equipment such as mylar balloons, hay or other interference resulting in a potential ignition source
Not Classifiable	Outage event with unknown cause or multiple potential probable causes identified
Operational	Unplanned outage resulting from operations
Tree-Within ROW	Outage attributed to vegetation contact with vegetation located within the power line right-of-way
Tree-Outside ROW	Outage attributed to vegetation contact with vegetation from outside the right-of-way

Pacific Power compiled an outage history from the past 10 years grouped by these ten outage categories, both inside of fire season (June 1 through October 1) and outside of fire season. Because “wire down” events represent situations with heightened ground fuel ignition correlation, wire down event data is also assessed. This data is overlaid in Figure 2 and Figure 3 below. As seen in Figure 3, outage and wire down events may happen more frequently outside of wildfire season which may be due to other factors such as winter storms.



	Object contact	Equipment failure	Contamination	Lightning	Utility work	Vandalism/theft	Wire-to-wire Contact	Unknown	Other
2022	849	788	20	113	6	14	33	392	156
2021	1007	679	31	61	6	9	27	390	160
2020	1323	809	20	113	3	9	28	426	373
2019	872	762	16	203	2	3	35	366	92
2018	837	667	12	133	0	3	36	410	97
2017	818	887	17	135	4	4	32	328	68
2016	665	629	19	16	8	2	28	378	54
2015	1169	955	31	137	5	4	34	528	154
2014	1069	938	22	235	5	7	28	642	68
2013	1174	866	12	422	8	8	46	669	153
2012	888	770	9	222	8	9	29	575	53
Total Wire Down Events	1,289	259	17	65	1	4	40	71	110

Figure 2: Historic Ignition Risk Drivers During Fire Season



	Object contact	Equipment failure	Contamination	Lightning	Utility work	Vandalism/theft	Wire-to-wire Contact	Unknown	Other
2022	2198	1685	79	4	6	26	93	678	838
2021	2556	1597	48	9	11	23	73	720	1171
2020	1704	1626	62	51	14	17	65	620	815
2019	1673	1670	24	28	7	8	66	562	937
2018	1353	1618	31	90	13	8	59	589	433
2017	1785	1744	44	46	7	8	61	646	1064
2016	1638	1628	41	42	5	6	55	555	472
2015	2126	2157	51	43	8	10	88	738	820
2014	2585	2142	46	26	8	10	68	929	705
2013	1052	1892	18	60	16	15	53	865	152
2012	2920	2177	50	42	7	13	87	948	1243
Total Wire Down Events	4,964	617	23	18	7	7	78	120	1,338

Figure 3: Historic Ignition Risk Drivers During Non-Fire Season

The analysis of risk drivers incorporates outage data collected through the company's normal outage response systems. As Pacific Power's risk modeling efforts evolve, there may be opportunities to gather more detailed data regarding outages, which may further refine the analysis of such data, to support the modeling and correlations between outages, risk events and ignition probabilities.

FIRE INCIDENT HISTORY

Pacific Power tracks fires potentially originating from Pacific Power equipment, as well as other fires that impact Pacific Power's facilities. An initial report of a fire can be obtained through a variety of sources. It is common for an initial report to come via a call to Pacific Power's system operations center from an emergency response agency or local government. Other times, Pacific Power field personnel may observe a fire or fire damage while performing work in the field. If certain regulatory criteria are met, information about the fire is reported to the Oregon Public Utility Commission.

After receiving an initial report of a fire incident, Pacific Power records the incident in a fire incident tracking database. Pacific Power gathers other information, as available, to record in the database. Fields maintained in this database include fire start date and time; location, with a latitude and longitude reference; land use in the area; fire size; suppression agency; facility identification; voltage; associated equipment; outage information; and the suspected initiating event. Data fields are organized to align with regulatory reporting requirements. Information is often estimated, based on known available information. For example, a recorded fire start time may be the time when the fire is first observed or when a report of fire is first received; but the precise time that the fire ignited may not be known. Fields are sometimes populated as "unknown" when there is insufficient available information. Fire incidents have been tracked since 2020, and the data is an input to the risk model.

ASSET INFORMATION

Information on transmission and distribution equipment, including type of equipment, location, installation date, and material is captured and used during analysis, where available.

1.2. RISK EVALUATION AND TOOLS

Pacific Power's baseline risk evaluation process employs the general concept that risk is the product of the likelihood of a specific risk event multiplied by the impact of the event, also referred to as risk consequence. The likelihood, or probability, of an event is an estimate of a particular event occurring within a given time frame. The impact of an event is an estimate of the effect to people and property 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, the company's image and reputation, and financial implications. Pacific Power uses modelling tools to evaluate both likelihood and impact.

FIRESIGHT

To perform risk evaluation, Pacific Power strives to combine utility and public data to analyze the components of risk associated with utility facilities in a consistent, repeatable way. As first outlined in the 2023 WMP,[4] Pacific Power procured and is currently implementing FireSight, previously known as the Wildfire Risk Reduction Model (WRRM), a commercially available module in a broader software suite from Technosylva referred to as Wildfire Analyst (WFA-E). As described in the 2023 WMP, Technosylva has provided advanced wildfire products and services to utilities throughout the United States since 1997 and other modules in WFA-E are used by the California Department of Forestry and Fire Protection (Cal Fire). With in-house fire and data scientists, Technosylva partners with key providers in fire planning, advanced data modeling, and wildland fire research and development to enhance the models used in their software. Technosylva has also

[4] See 2023 WMP at page 25.

published studies in scientific journals and wildfire industry publications such as Current Opinion in Environmental Health and Science[5] and International Journal of Wildland Fire.[6]

FireSight specifically builds upon the quantitative risk model developed by Technosylva that associates wildfire hazards with the location of electric overhead assets. FireSight is used to forecast the consequence or impact of a wildfire from a given ignition point in Pacific Power's service territory based on the potential spread of a wildfire, should it occur. Pacific Power chose to implement FireSight based on Technosylva's experience with other West Coast utilities and their partnerships with experts in wildfire risk modeling and fire data science.

The FireSight model, which is depicted in Figure 4below, combines the utility asset information and data described in Section 1.1 with public data regarding community characteristics, terrain, vegetation, and weather information, to provide ignition risk scores at points along a circuit. Specific to this model, Technosylva sources information on climate, historic weather conditions, terrain, fuels, population, and the built environment (buildings and roads) from public sources. A complete list of inputs, with source and

[5] Cardil, Adrián, Santiago Monedero, Gavin Schag, Sergio de Miguel, Mario Tapia, Cathelijne R. Stoof, Carlos A. Silva, Midhun Mohan, Alba Cardil, and Joaquin Ramirez, "Fire behavior modeling for operational decision-making." Current Opinion in Environmental Health and Science, Volume 23. October 202

[6] Cardil, Adrián, Santiago Monedero, Phillip SeLegue , Miguel Ángel Navarrete, Sergio de-Miguel, Scott Purdy, Geoff Marshall , Tim Chavez, Kristen Allison, Raúl Quilez, Macarena Ortega, Carlos A. Silva, and Joaquin Ramirez, "Performance of operational fire spread models in California," International Journal of Wildland Fire, July 7, 2023, Sourced November 2, 2023.

frequency of update, is provided in Appendix C – Wildfire Risk Modeling Data Inputs, consistent with OAR 860-300-030 (A).

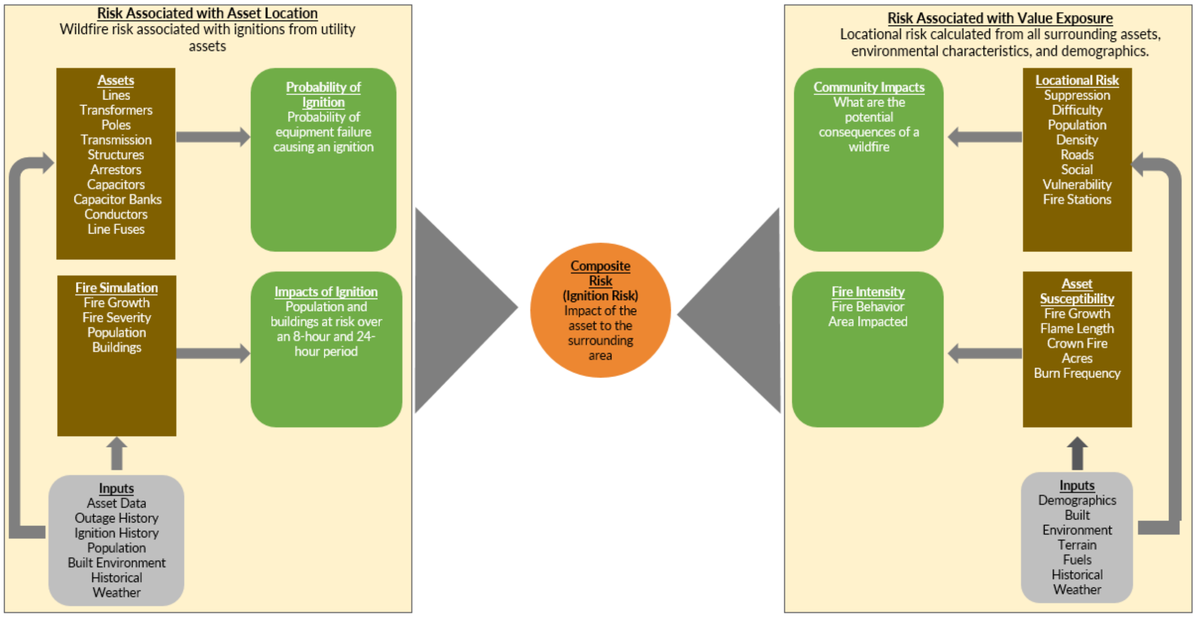


Figure 4: Overall FireSight Model for Risk Estimates

The FireSight model has two primary parts, Risk Associated with the Asset Location (RAIL) and Risk Associated with Value Exposure (RAVE). RAIL, depicted on the left side of the figure above, represents the risk presented by the asset, based on its characteristics, including age and materials. RAIL assesses the risk by associating the ignition impact over an eight-hour and 24-hour period to a specific asset. The eight-hour period is the typical period used by utilities to model risk, but there is growing interest in 24-hour modeling risk to understand how that changes the risk profile.[7] Therefore, Pacific Power is modeling both to better understand if there are significant differences in the results that may impact mitigation efforts.

[7] California Office of Energy Infrastructure Safety. "Standardized Wildfire Risk Type Classifications and in Situ Wildfire Risk Assessment." Risk Modeling Working Group. October 11, 2023.

Factors considered in RAIL calculations include:

- Surface and canopy fuels outlook in 2030, including consideration of climate change impacts in the modeling.
- Topography.
- Wind speed and direction.
- Historical fire occurrence identifying time of data, typical weather conditions, and duration.

Outputs from RAIL include:

- Ignition risk from overhead transmission and distribution assets.
- Potential fire characteristics: Fire size, rate of spread, potential for crown fire, flame length.
- Population at risk.
- Number of buildings at risk.

Risk Associated with Value Exposure (RAVE), depicted on the right side of the figure above, assesses the characteristics of the area that is under risk of ignition. Community demographics, geography, and the built environment influence how risky or resilient a community is to wildfire. RAVE is independent of the asset risk calculated in RAIL and considers the risk associated with additional factors:

- Population density.
- Socially vulnerable populations such as the elderly, people with a disability, or people at or below the poverty level.
- Infrastructure: Major and minor road density and building density.
- Suppression difficulty: Terrain, fuels, and fire station locations all impact how quickly firefighters can respond to a fire in the initial attack.
- Crown fire crowning acres: the amount the fire can spread through crowning in continuous spread through the tree crowns.

RAVE Outputs:

- Community impacts: How vulnerable a community is to wildfire and the potential consequences.
- Fire intensity: How a fire is expected to behave and what area may be impacted from the point of ignition.

Consideration of Climate Change in Wildfire Risk Modeling

Climate change does have impacts on wildfire risk. A 2018 study by the Climate Adaptation Science Centers warned that,

> "A warming climate will have profound effects on fire frequency, extent, and severity in the Pacific Northwest. Increased temperatures, decreased snowpack, and earlier snowmelt will lead to longer fire seasons, lower fuel moisture, higher likelihood of large fires, and greater area burned by wildfire. Interactions between fire and other disturbance agents (e.g., drought, insect outbreaks) will drive ecosystem changes in a warming climate. Increased tree stress and interacting effects of drought, insects, and disease may also contribute to increasing wildfire severity and burned areas. Climatic changes and associated stressors will interact with vegetation conditions, as affected by historical land uses such as tree harvest and fire suppression, to affect fire regimes and forest conditions in the future.[8]"

On July 23, 2023, California Office of Energy Infrastructure Safety (OEIS), led a scoping meeting with the California IOUs[9] regarding how utilities can best learn from each other, external agencies, and outside experts on the topic of integrating climate change into projections of wildfire risk.[10] Pacific Power intends to participate in subsequent

[8] Harvey, B., Peterson, D., Havlovsky, J. "Changing Fires, Changing Forests: The Effects of Climate Change on Wildfire Patterns and Forests in the Pacific Northwest." Sourced September 22, 2023.

[9] PacifiCorp, d/b/a Pacific Power in Oregon, Washington and California, and Rocky Mountain Power in Idaho, Utah, and Wyoming, provides electric service to customers in Oregon, Washington, California, Utah, Idaho, and Wyoming.

[10] California Office of Energy Infrastructure Safety. "Scoping Meeting: Climate Change and Fire Risk-Consequence Modeling - July 25, 2023." Sourced October 19, 2023.

workshops to learn more about how other IOUs are integrating climate change into their wildfire risk models and guidance experts are providing regarding impacts of climate change on wildfire risk.

Currently, the FireSight model accounts for climate change in the fuels moisture model that is an input to the Composite Risk Score. Pacific Power will use learnings from the OEIS workshops as an input to evaluating if there are additional risk variables that are impacted by climate change and the feasibility of integrating them into wildfire risk modeling. This is discussed further below as improvement initiative “Evaluation of Climate Change Impacts on Wildfire Risk Models.”

COMPOSITE RISK SCORE

The composite risk score is a combination of the RAIL and RAVE and reflects three components:

1. Where is the predicted impact? This is the measure of the population and buildings if there is an ignition.
2. How destructive could the fire be? This is the expected fire behavior over the forecast fire area.
3. How resilient is the community? This is affected by the difficulty of suppression and population characteristics.

Pacific Power models and calculates separate composite risk scores for wind-driven and fuel/terrain-driven wildfires to account for the unique characteristics of its service territory that spans both steep forested areas as well as high desert areas. Table 2 below shows the unique characteristics of each wildfire type modeled.

Table 2: Comparison of General Characteristics of Wind-Driven and Fuel/Terrain-Driven Wildfires

Category	Wind-Driven Wildfires	Fuel/Terrain-Driven Wildfires
Locational Risk	More likely in areas subject to PSPS (Public Safety Power Shutoff)	Confined to areas of complex fuels and terrain with difficult access
Frequency	Some years have none; others several	Annually during peak fire season
Event Duration	1-3 days per event	Can persist several weeks or months
Outage Risk	Wind-driven and somewhat predictable	Difficult to predict
Consequence	Immediately catastrophic	May be catastrophic over time

Calculating the risk separately and then combining them into a single composite risk, as shown in Figure 5below, provides a robust risk calculation and identification of the risk driver at a location to apply the appropriate mitigation.

Figure 5: Composite Risk Consideration Wind-Driven and Fuel/Terrain-Driven Events

Figure 6below shows the inputs and weightings for the composite risk for wind-driven and fuel/terrain-driven wildfires. On the left side of the table are the RAIL inputs with the selected input for the type of wildfire, the percentile selected and the weighting for each variable. On the right side of the table are the RAVE inputs with the weightings for each variable, there are no percentiles for these inputs as they are relatively static values, i.e., the number of fire stations the number of disabled people in geographic area.

Fuel/Terrain

Risk Associated with Ignition Location (RAIL) Component: 60%

RAIL Inputs	Percentile	Weight (%)
Fire Behavior Index	95	20%
Fire Size Potential	95	20%
Flame Length	95	20%

+

Risk Associated with Value Exposure (RAVE) Component: 40%

RAVE Inputs	Percentile	Weight (%)
Terrain Difficulty Index	N/A	25%
Fire Station Density	N/A	10%
Fuel Model Majority	N/A	5%

Wind

Risk Associated with Ignition Location (RAIL) Component: 80%

RAIL Inputs	Percentile	Weight (%)
Rate of Spread	95	30%
Population Impacted	95	25%
Buildings Destroyed	95	25%

+

Risk Associated with Value Exposure (RAVE) Component: 20%

RAVE Inputs	Percentile	Weight (%)
Terrain Difficulty Index	N/A	10%
Disability Population	N/A	5%
Poverty Population	N/A	5%

Figure 6: Inputs and Weightings for Composite Risk Calculation

The inputs and percentages above were selected based on inputs from internal subject matter experts and reviews of other utilities risk models. A sensitivity analysis was performed on the selected inputs and weightings to validate that the selected percentiles and weightings identified circuits expected to be higher risk for fuels or terrain driven wildfires based on subject matter expertise.

Figure 7below is an example of the difference in the Fuel/Terrain-Driven and Wind-Driven Composite Risk Score on a Pacific Power circuit near Billy Mountain, OR. The terrain here is steeper and has more fuels, which is reflected in an average Fuel/Terrain Driven Composite Risk score of 0.84 compared to an average Wind-Driven Composite Risk score of 0.35.

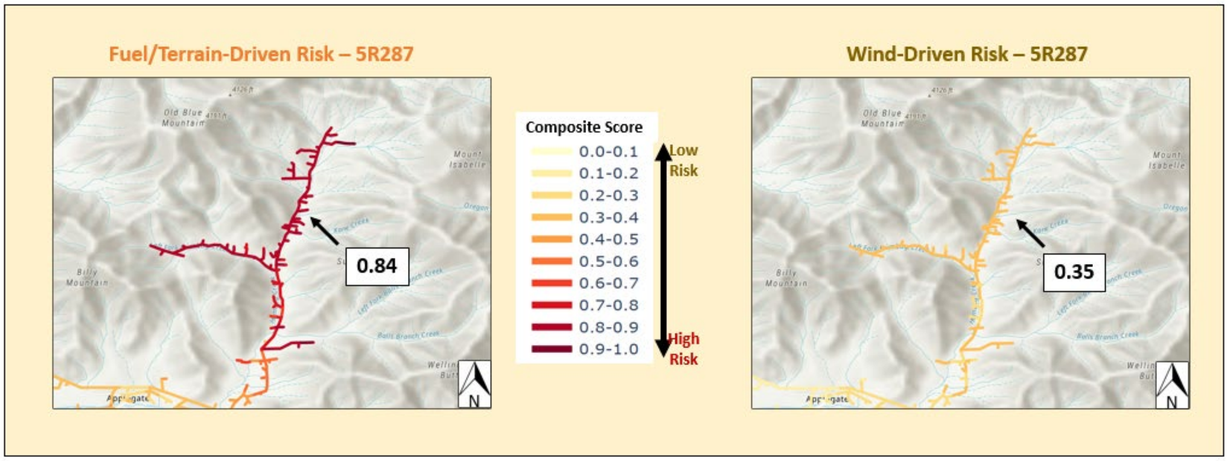


Figure 7: Illustrative Example of Fuel/Terrain-Driven Composite Risk Compared to the Wind-Driven Composite Risk Near Billy Mountain, OR Circuit 5R287

Figure 8below is an example of the difference in the Fuel/Terrain-Driven and Wind-Driven Composite Risk Score on a Pacific Power circuit near Ashland, OR. Here the terrain is flatter, and the Wind-Driven Composite Risk is significantly higher than the Fuel/Terrain-Driven Composite Risk score.

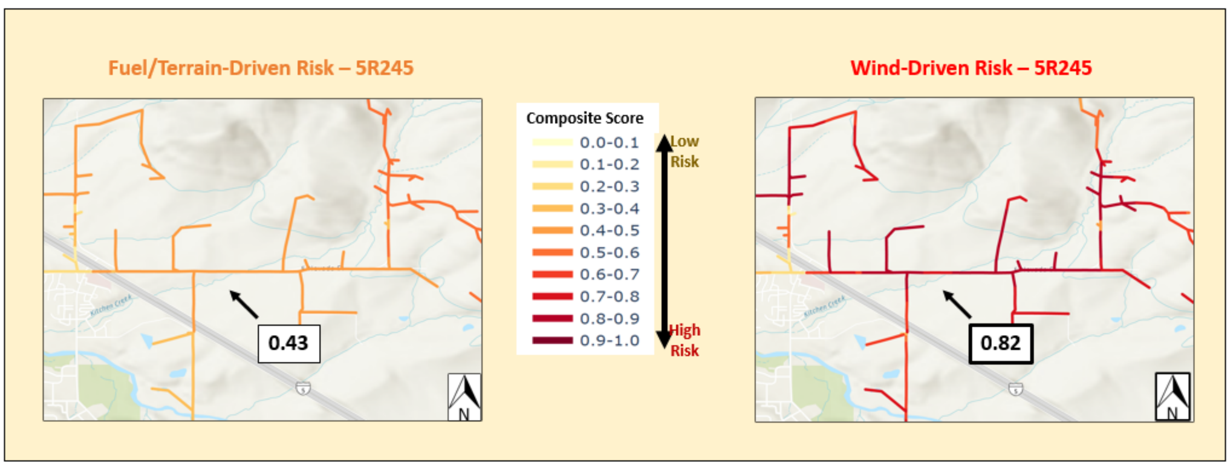


Figure 8: Illustrative Example of Fuel/Terrain-Driven Composite Risk Compared to the Wind-Driven Composite Risk Near Ashland, OR Circuit 5R245

As seen in Figure 8above, the composite risk scores can vary along a circuit due to changes in fuels, terrain, build environment, assets and community demographics that affect the risk score inputs. This variation is seen below in the change in composite risk score for a circuit segment as well as visually in the change in color along the circuits. The composite score is calculated for each circuit segment using an equation that calculates a wind-driven and terrain-driven risk as shown in Figure 9below.

Risk Associated with Ignition Location (RAIL) Component | **Risk Associated with Value Exposure (RAVE) Component**

(Variable 1(Weight; %)) + (Variable 2(Weight; %)) + (Variable 3(Weight; %)) **+** (Variable 1(Weight; %)) + (Variable 2(Weight; %)) + (Variable 3(Weight; %))

Figure 9: Calculation of Wind-Driven and Fuel/Terrain-Driven Composite Risk

The calculation for the combined risk score for each circuit segment is shown in Figure 10 below. Each composite score is on a scale of 0-1.

$$\frac{\text{Wind Driven Composite Risk} + \text{Terrain Driven Composite Risk}}{\text{Largest Composite Score All Circuits}}$$

Figure 10: Combined Composite Risk Score Calculation

The FireSight tool, together with composite and combined composite risk score methodology described above, were leveraged to create two, parallel evaluations. First, assuming a fixed, equal probability, the wind-driven and fuel/terrain-driven composite risk scores were calculated and compiled to inform an evaluation of baseline wildfire risk, including whether to modify the geographic boundaries of the FHCA. As part of a parallel effort, the combined, composite risk scores were calculated using the historic risk driver analysis as an indicator of probability to inform a risk ranking of circuits and potential prioritization for grid hardening. These applications are described in more detail below.

FIRE HIGH CONSEQUENCE AREA (FHCA)

Pacific Power has identified areas of heighted risk of wildfire, with delineated geographic areas referred to as the Fire High Consequence Area or "FHCA." The geographic boundaries of the FHCA are synonymous with the boundaries of Pacific Power's designated High Fire Risk Zones (HFRZ), as that term is defined in OAR 860-024-0001. (While the geographic areas are the same, this WMP uses the term "FHCA," rather than "HFRZ," for consistency with internal usage.) The FHCA sets geographic boundaries for wildfire mitigation programs including asset management and vegetation management discussed in Section 2.2 and Section 3.2 respectively.

EXISTING FHCA BOUNDARIES

As described in Pacific Power's 2023 WMP, the FHCA was developed in collaboration with Reax Engineering, a consultant specializing in wildland fire computer modelling, and patterned after the methodology developed through a multi-year, iterative process in California. Reax conducted the wildfire risk analysis using Monte-Carlo simulations incorporating the multiple datasets and data sources generally outlined in prior WMPs. Through this process, individual blocks of geographic area, each a 2-kilometer square cell, received a grid score corresponding to its relative wildfire risk. As a result, Pacific Power generated a map of the FHCA, which was included as Figure 3 in the 2023 WMP and depicted in Figure 11 below.

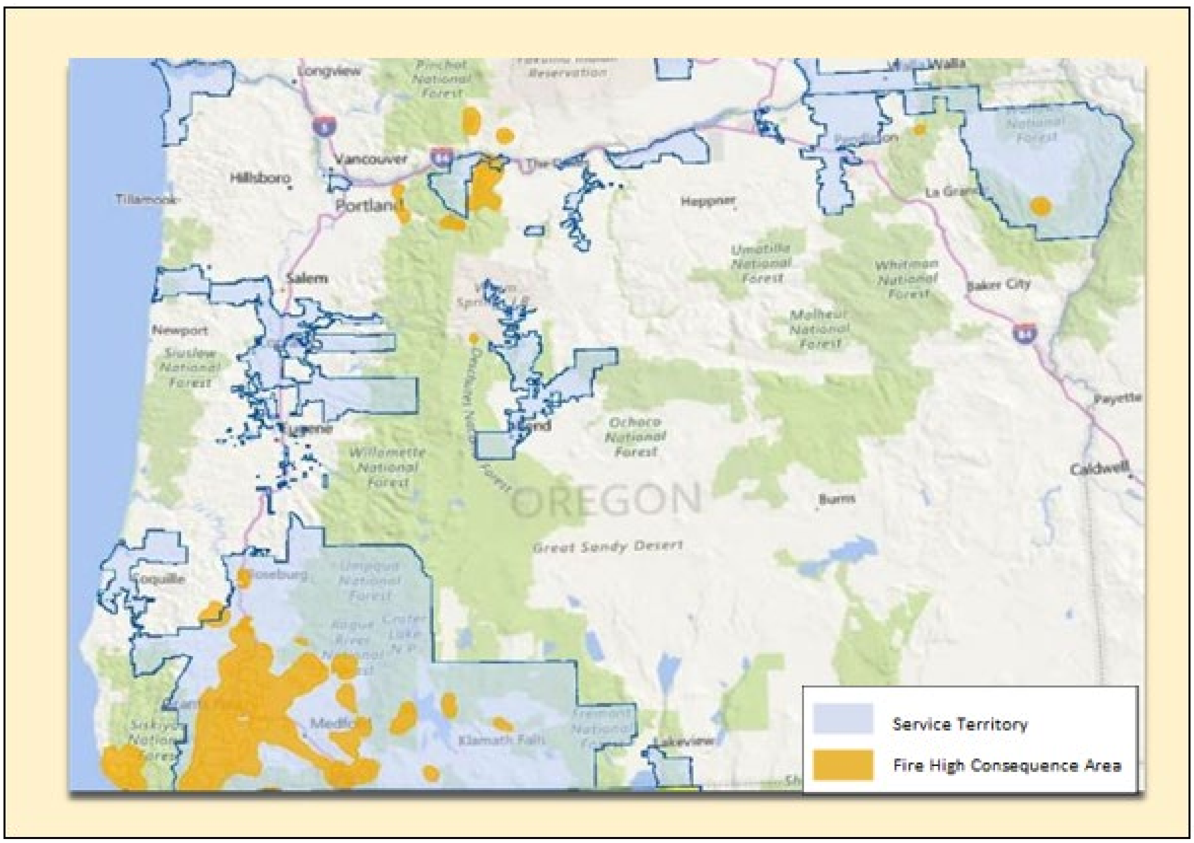


Figure 11: 2023 WMP Fire High Consequence Area (FHCA) Map

2024 MODIFICATIONS TO FHCA

Over the past year, Pacific Power incorporated new data, tools, and processes to evaluate additional areas for inclusion in the FHCA. More specifically, Pacific Power leveraged

FireSight to model risk scores for wind-driven and fuel/terrain-driven risk on each circuit assuming a probability factor of 1 as described in the Composite Risk Score section above to focus on the consequence of potential ignitions. Based on this approach and, specifically, the FireSight model risk scores, Pacific Power identified additional geographic areas for inclusion within the FHCA, depicted in red in Figure 12 below.

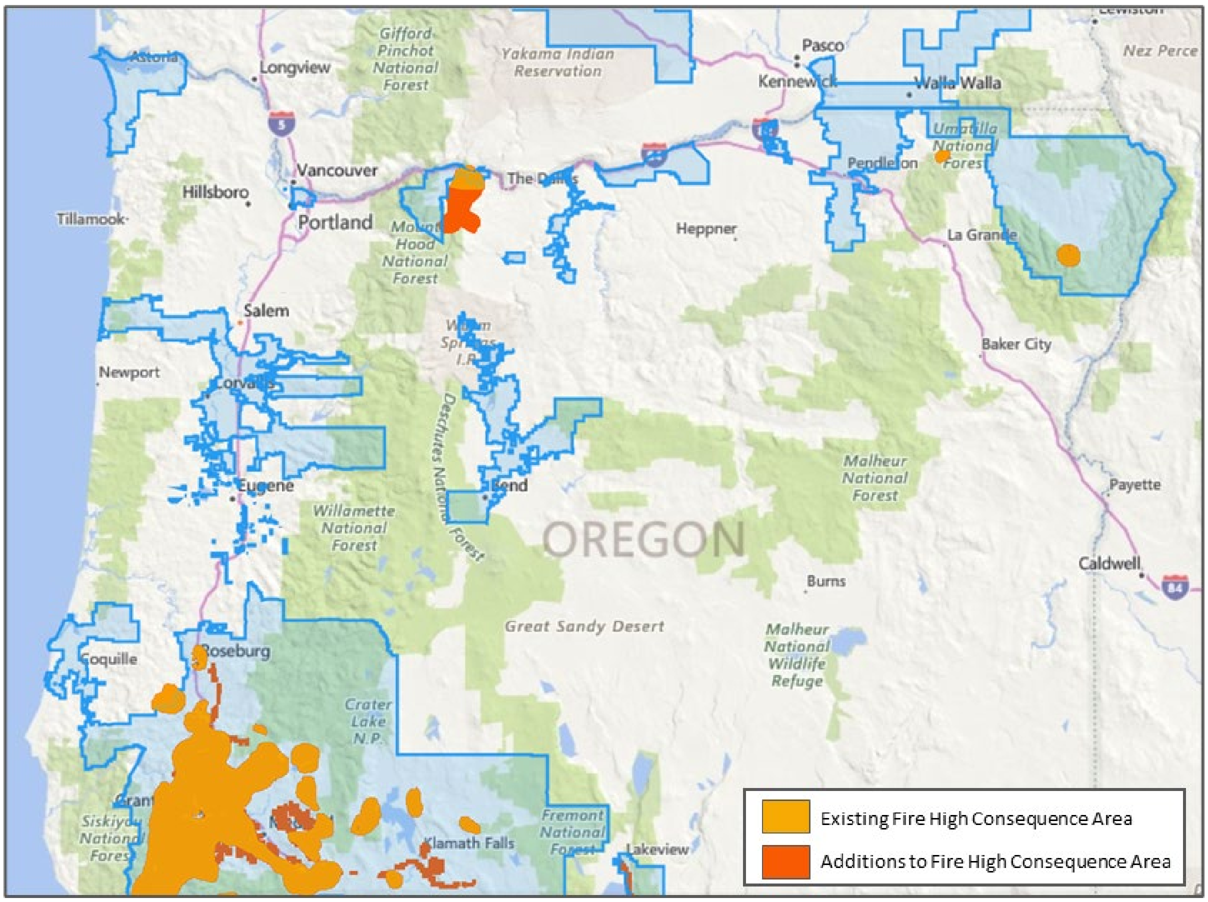


Figure 12: 2024 Additions to the FHCA

Adding these areas to the FHCA results in an addition of approximately 965 miles of distribution and transmission lines within the FHCA. The breakdown of current FHCA and incremental line miles is summarized in Table 3 below and the total number of assets in the FHCA is in Table 4.

Table 3: FHCA Line Miles

	Total Service Territory	Existing FHCA		2024 FHCA Additions	
	Line Miles	Line Miles	% of Service Territory	Line Miles	% of Service Territory
OH Transmission Line Miles	3,059	413	2%	230	1%
57kV Transmission Lines	14	0	0%	0	0%
69kV Transmission Lines	914	96	1%	44	0%
115 kV Transmission Lines	999	177	1%	67	0%
230 kV Transmission Lines	610	90	1%	58	0%
500kV Transmission Lines	522	50	0%	61	0%
OH Distribution Line Miles	14,075	2,275	13%	735	4%
Total	**17,133**	**2,688**	**16%**	**965**	**6%**

Table 4: Breakdown of Assets in 2024 FHCA

Distribution Asset Type	Count
Distribution Circuits	130
OH Distribution Miles	3,012
Distribution Poles	77,233
OH Transformers	39,590

Transmission Asset Type	Count
Transmission Lines	56
Transmission Miles	643
Transmission Poles	3,115
Underbuild Poles	3,620

Areas of Interest

Pacific Power continues to study other geographic areas for wildfire risk, even if FireSight model risk scores did not warrant inclusion of such areas in the FHCA at this time. The FireSight model risk scores reflect the reality that there is a spectrum of wildfire risk. Not surprisingly, certain areas, such as wooded forests have more wildfire risk than other areas, such as irrigated agricultural areas. Along those same lines, certain areas have FireSight model risk scores which approach the scores resulting in FHCA treatment. Pacific Power will continue to evaluate those areas, including for possible future expansion of the FHCA. To that end, Pacific Power has identified additional “Areas of Interest,” which reflect geographic areas with above average FireSight model risk scores. The Areas of Interest are grouped in two parts: Area of Interest I refers to areas with risk scores closest to the risk scores used to demarcate the FHCA, while Area of Interest II refers to areas with risk scores lower than Area of Interest I. Expressed as percentiles, the FHCA reflects areas with FireSight model risk scores in the 85-100 percentile; Area of Interest I reflects areas in the 65-85 percentile; and Area of Interest II reflects areas in the 45-65 percentile. The Areas of Interest, juxtaposed against the 2024 FHCA, are shown in Figure 13 below.

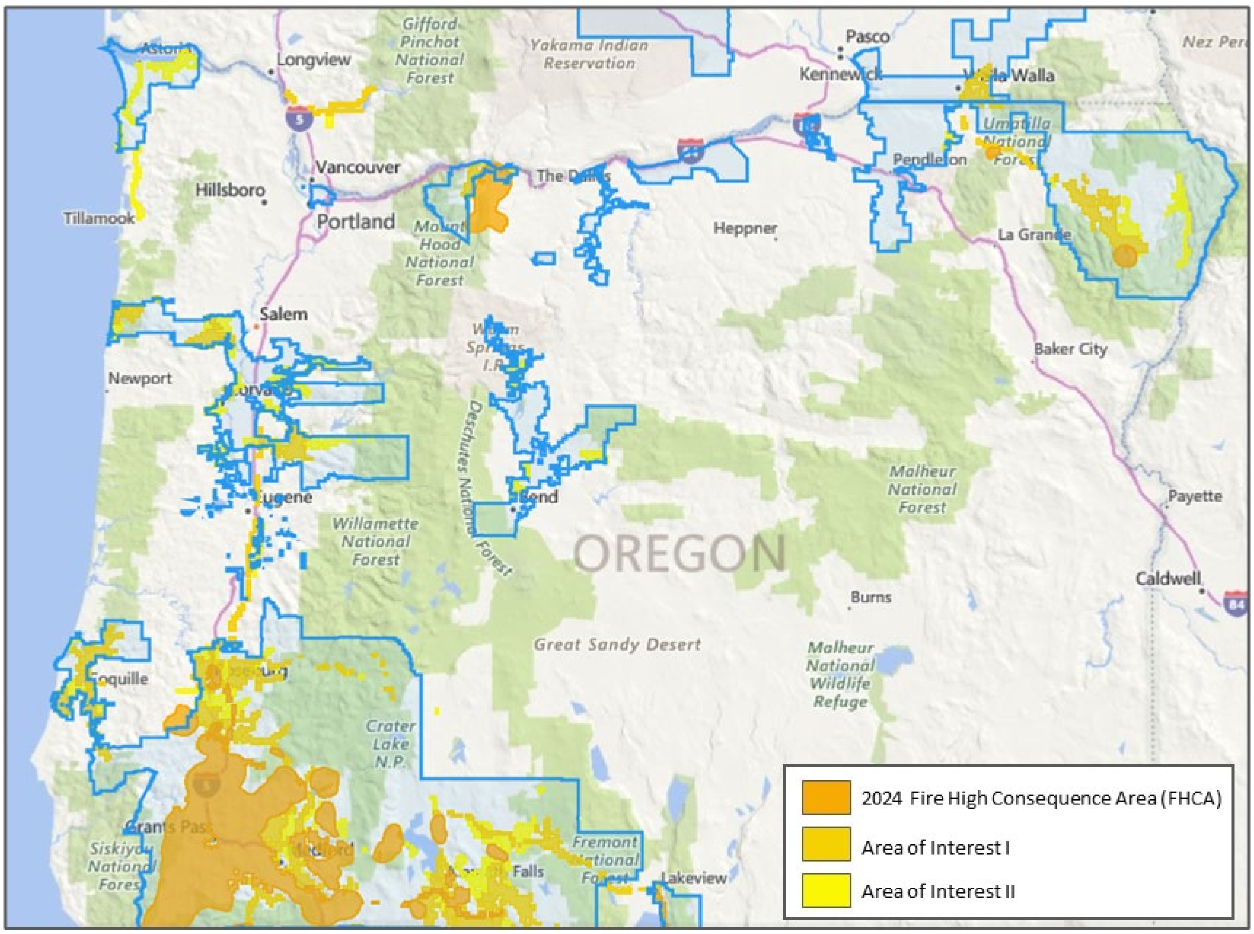


Figure 13: 2024 FHCA and Areas of Interest

Comparing the FHCA map with the Oregon Explorer[11] maps of wildfire risk as depicted in Figure 14 below, there is general alignment with the general wildfire risk and risks to assets, people, and property either in the FHCA and in the areas of interest.

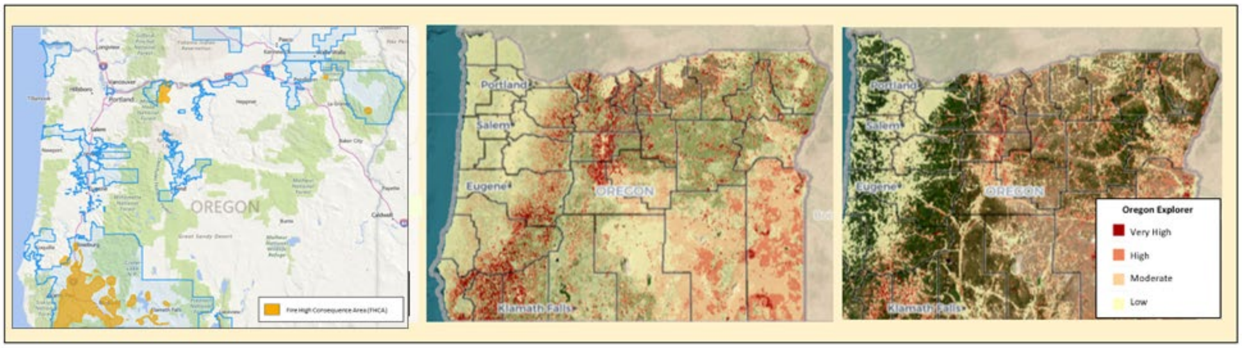


Figure 14: Comparison of Pacific Power FHCA and Areas Under Review (left) to Oregon Explorer Maps of Overall Wildfire Risk (center) and Wildfire Risk to Assets, People and Property (right)

Consistent with OPUC OAR 860-300-0030, Pacific Power will confer with state agencies such as the Oregon Department of Forestry (ODF) and Oregon State Fire Marshal (OSFM) regarding the FHCA to determine whether additional modifications might be appropriate.

Pacific Power plans to provide the updated FHCA boundary to the following utilities with assets in close proximity to the FHCA boundary:

- City of Ashland Municipal Electric Utility
- Coos-Curry Electric Cooperative
- Douglas Electric Cooperative
- Hood River Electric Cooperative
- Northern Wasco County Public Utility District
- Umatilla Electric Cooperative

11 Oregon Department of Forestry, United States Forest Service. Oregon Explorer, [CWPP Planning Tool (oregonexplorer.info)](oregonexplorer.info). Sourced November 21, 2023.

- Wasco County Electric Cooperative

Finally, Pacific Power also intends to continue evaluating the FHCA on an annual basis to incorporate new data, modeling techniques, and stakeholder input.

RISK RANKING AND PRIORITIZATION

As part of a parallel effort, the FireSight tool was also used to create a risk ranking of circuits for potential prioritization for grid hardening by incorporating the historic risk driver analysis as an indicator of probability and modeling the combined, composite risk scores. Table 5 below shows the 20 highest risk circuit segments in Oregon by combined composite expected (likelihood of wildfire) score. The Wind-Driven and Terrain-Driven scores are provided to show the driver of the risk. This information can be used to identify circuits for scoping of grid hardening projects to mitigate the risk of wildfire.

Table 5: Highest Risk Circuits by Combined Composite Risk Score

Circuit	Composite - Mean	Composite - Max	Wind-Driven Score - Mean	Fuel/Terrain-Driven Score - Mean
5C9	0.52	0.52	0.00	0.98
4U37	0.52	0.52	0.03	0.93
5D47	0.52	0.69	0.08	0.88
5L113	0.52	0.58	0.04	0.92
7M26	0.51	0.52	0.02	0.93
7M29	0.51	0.52	0.02	0.93
5L4	0.51	0.66	0.06	0.90
4M130	0.51	0.56	0.02	0.93
7A354	0.51	0.54	0.02	0.94
5R257	0.51	0.51	0.02	0.93
7L25	0.51	0.65	0.05	0.90
4M430	0.51	0.51	0.01	0.93
4M429	0.51	0.51	0.01	0.93
4M428	0.51	0.51	0.01	0.93
4M427	0.51	0.51	0.01	0.93
4M396	0.51	0.51	0.01	0.93

Circuit	Composite - Mean	Composite - Max	Wind-Driven Score - Mean	Fuel/Terrain-Driven Score - Mean
4M394	0.51	0.51	0.01	0.93
5L2	0.51	0.77	0.07	0.87
4M266	0.51	0.65	0.02	0.93
5D12	0.51	0.51	0.01	0.93

For illustrative purposes, Figure 15 below shows the location of these circuits.

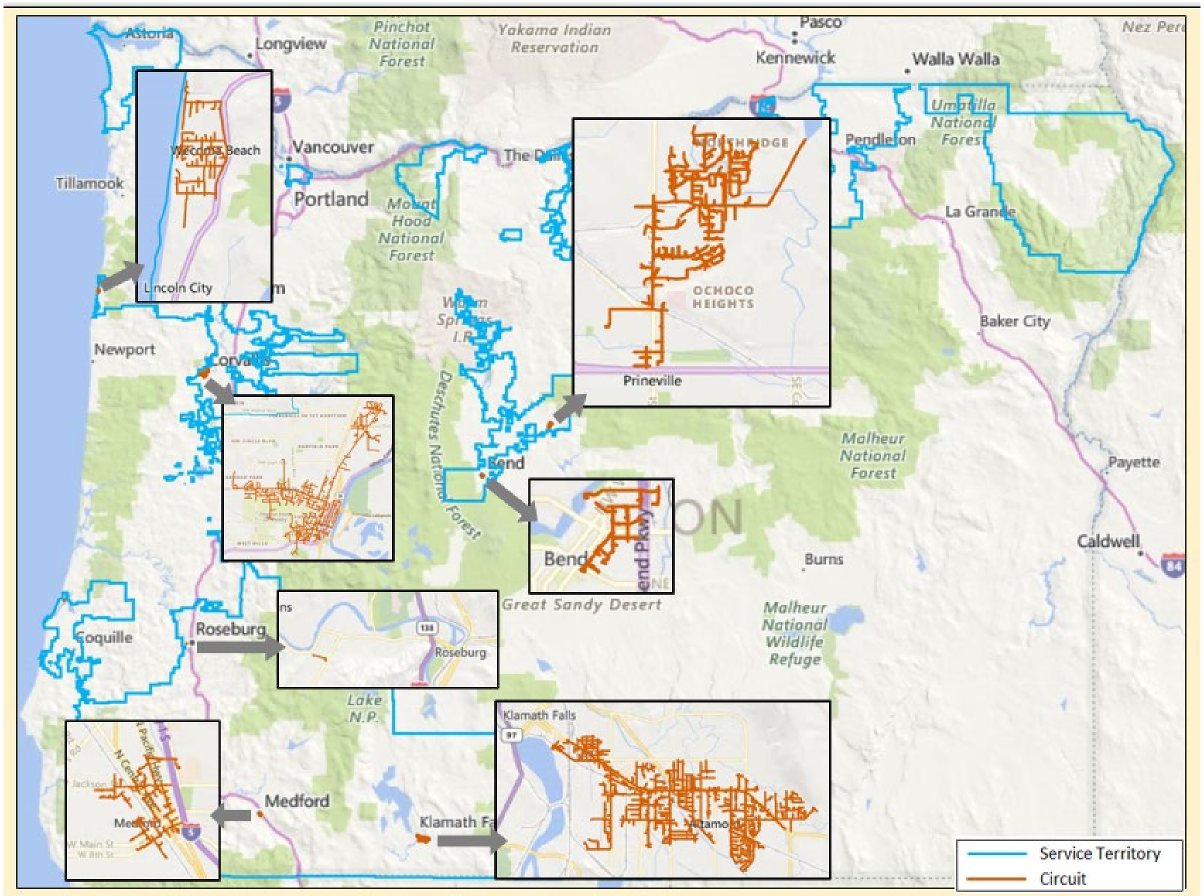


Figure 15: Location of the Highest Combined Composite Risk Circuits

1.3. RISK TREATMENT - PROGRAM SELECTION AND PRIORITIZATION

Pacific Power applies a high-level decision-making process that aligns with many other utilities to develop specific projects or programs, not including compliance driven system wide programs. The high-level process, represented by Figure 16, includes four key phases: (1) risk modeling and assessment, (2) program identification and planning, (3) project evaluation and selection, and (4) implementation and monitoring. While not specifically shown in the general framework, part of the process allows for a program or project to be moved back to a previous step if needed.

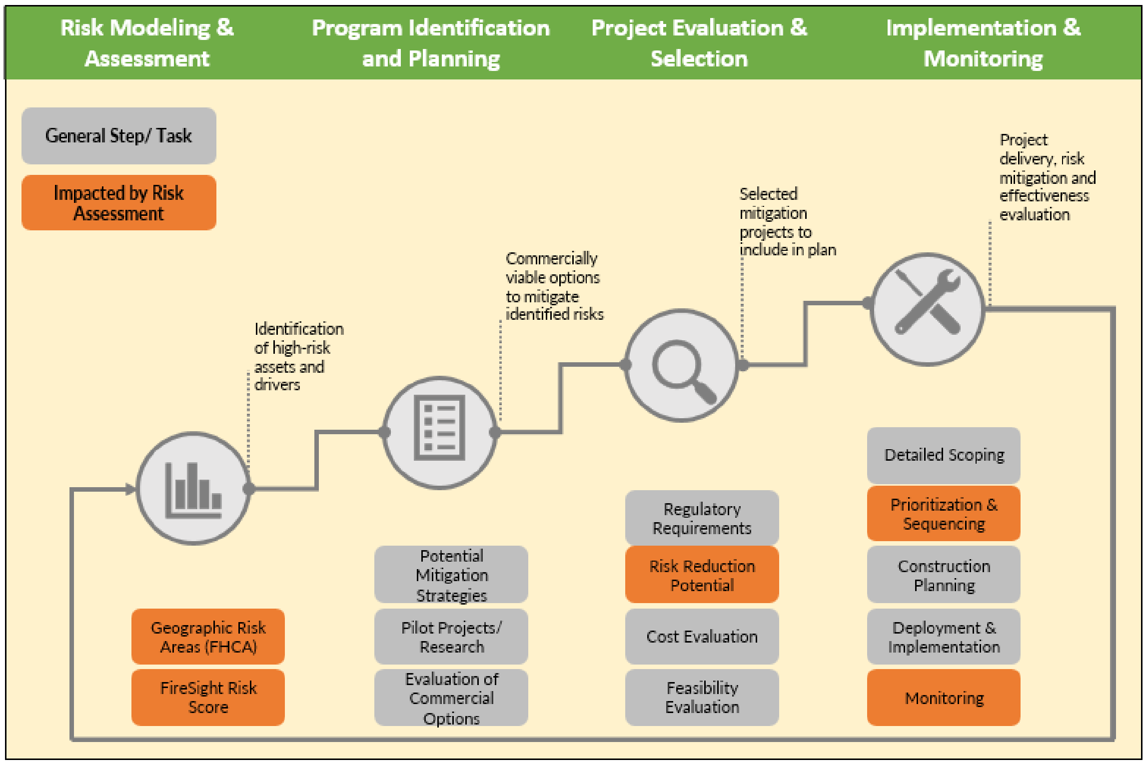


Figure 16: High Level Program and Project Selection Process

PHASE 1 – RISK MODELING AND ASSESSMENT

As described in Section 1.2, baseline risk mapping identifies the areas of heightened wildfire risk within Pacific Power's service territory. As described in Section 0, Pacific Power is transitioning to using the FireSight to further identify and prioritize specific circuits that have a heightened risk of wildfire, like those identified in Figure 15 above. The circuits are prioritized for identification of mitigation options as described in Phase 2 – Program Identification and Planning and Phase 3– Project Evaluation and Selection below.

PHASE 2 – PROGRAM IDENTIFICATION AND PLANNING

Identifying mitigation options requires an evaluation of current proven industry practices and technology. Pacific Power has relationships with other utilities across multiple states, and discusses industry practices with those utilities, learning from their experiences and evaluates proven industry solutions for selection as a mitigation program.

Additionally, information from ignition risk drivers helps shape Pacific Power's programs which typically focus on methods, tactics, and technologies that reduce outages or, more specifically, fault events. For example, if the risk of utility-related wildfire exists due to equipment failure, an increase in inspections or maintenance activities can help mitigate the risk. If the risk exists due to potential contact with third party objects, constructing a system more resilient to contact with objects can help to mitigate the risk.

Table 6 below generally maps Pacific Power's key risk drivers to the primary programs, demonstrating what elements impact a group or groups of risk drivers. It is important to note that elements may not eliminate a risk driver but are designed to mitigate the risk associated with that driver. For many risk drivers, risk is mitigated through a combination of programs and there is not always a 1:1 relationship between a risk driver category and a mitigation program. All elements and programs in the plan work together to collectively mitigate wildfire risk.

Table 6: Risk Driver Mapping to Potential Mitigation Program(s)

Key Risk Driver	Significant Contributor to Wire Down Events	Potential Mitigation Program Categories				
		Asset Inspections	Vegetation Management	System Hardening	Field Operations	System Operations
Object Contact	✓	✓	✓	✓	✓	✓
Other	✓	✓	✓	✓	✓	✓
Equipment Failure	✓	✓	✓	✓	✓	✓
Unknown	✓	✓	✓	✓	✓	✓
Wire-to-wire contact	✓	✓		✓	✓	✓

Key Risk Driver	Significant Contributor to Wire Down Events	Potential Mitigation Program Categories				
		Asset Inspections	Vegetation Management	System Hardening	Field Operations	System Operations
Contamination		✓		✓	✓	✓
Utility Work		✓		✓	✓	✓
Vandalism/ Theft		✓		✓	✓	
Lightning				✓		

As program scoping identifies potential mitigations, it is designed to make sure the ignition risk driver is addressed and considers other programs to avoid duplicate efforts.

PHASE 3– PROJECT EVALUATION AND SELECTION

Pacific Power is implementing tools and processes to ensure that projects in programs are cost-effective and technically feasible. Figure 17 below shows the current high-level process that is described in detail below.

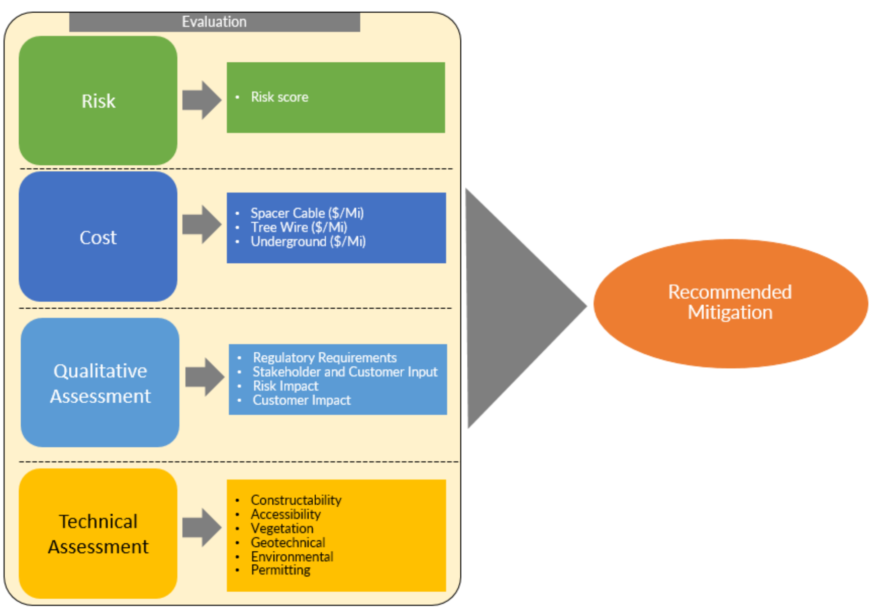


Figure 17: Current Project Evaluation and Selection Process

Risk Identification

The mitigation projects in Appendix D – Planned Projects were selected using the 2018 FHCA map to identify areas of risk where grid hardening efforts should take place to mitigate utility ignition risk. With the implementation of the Composite Risk Score to identify the specific circuits and segments of elevated risk, identification is shifting to identifying the highest risk circuits by composite risk score to allow planning to prioritize evaluation based on a quantified risk score. Due to the nature of Pacific Power's service territory, circuits with a high fuel/terrain-driven composite risk score will be prioritized for mitigation.

Cost

Pacific Powers considers project costs when planning, evaluating, and selecting initiatives. For example, Pacific Power evaluates the potential to convert overhead lines to underground lines for rebuild projects on a project-by-project basis. Through the design process, each individual project is assessed to determine whether sections of the rebuild should be completed with underground construction. Pacific Power has experience that in a more remote, heavily forested location with few customer connections, underground can be a cost-effective solution when compared to covered conductor.

Qualitative Evaluation

Pacific Power uses qualitative evaluation of proposed projects. Qualitative considerations include:

- Regulatory requirements – Pacific Power considers regulatory requirements when identifying and prioritizing projects to ensure alignment and compliance. For example, Pacific Power considers the inspection requirements within the FHCA when planning and completing the company's asset inspection programs.

- Internal stakeholder and customer input – Initiative identification and evaluation is coordinated with various stakeholder groups within the company and departments that participate in the development and selection of initiatives that align with risk reduction goals. In addition to internal stakeholder input, Pacific Power works with customer input through hosting webinars that engage local communities and Public Safety Partners on wildfire safety.
- Wildfire risk impact – Mitigation initiatives are evaluated to align with industry practices and programs in place at other utilities that have shown to reduce wildfire risk. Mitigation initiatives are prioritized along with known historical causes of risk.
- Customer impact – The evaluation and identification of initiatives considers customer impact in elevated risk areas and its location or overlapping of local communities to determine prioritization and urgency of initiative selection. Customer impact may include an example such as re-routing an existing line that may interfere with the customers' ability in the future to construct a facility (barn, shed, etc.).

Technical Feasibility

Feasibility analysis is performed as a qualitative input to mitigation selection. Technical analysis may indicate that the most effective mitigation is not feasible due to other considerations. Technical feasibility is also used to evaluate mitigations that currently do not have effectiveness measures. Technical feasibility considers the following:

- Constructability— Ease of implementation and constructability are factors in selecting the final mitigation technique. For example, commercially available solutions such as covered conductor may be widely implemented as a mitigation technique while new and emerging technologies, such as DFA (Distribution Fault Anticipation) may be implemented as pilot projects with limited application.

- Accessibility— Access to the location to perform the work. For example, undergrounding in a steep terrain may be inadvisable due to the equipment needed and the ability to safely operate equipment in the terrain.
- Vegetation— Impacts to vegetation because of the proposed project are considered, including mitigation efforts during the project and any potential remediation needed after the project due to removal of vegetation.
- Geotechnical— Identification of the type of earth below ground may affect the mitigation selected. For example, solid rock or rocky soil may not be conducive to undergrounding due to technical feasibility or cost and covered conductor may be a more cost-effective solution.
- Environmental— Impacts to air, soil, or water of a proposed mitigation.
- Permitting— The ability to successfully acquire permits as well as the number of permits required is a consideration. For example, a covered conductor project may be selected over undergrounding in certain circumstances because permitting can be completed more quickly with fewer barriers. Conversely, undergrounding may be moved forward where alignment with other utilities, such as telecom, presents an opportunity for cost sharing and joint location to a new trench or underground infrastructure.

2024-2027 projects are listed in Appendix D – Planned Projects. Projects planned to begin execution in 2024 have a high degree of confidence in their start date. Projects that are targeted for 2025-2027 execution have lower confidence in their start dates as they may be impacted by progress of in-flight projects, resourcing, permitting, and materials. Projects in Appendix D that were planned prior to Pacific Power implementing FireSight and composite risk, and a baseline composite risk was not captured at that time. These plans are subject to change based on added information such as the results of the technical feasibility, customer and community feedback, or changes in regulation and will be updated as those issues become known.

Risk Spend Efficiency

Pacific Power is planning to implement Risk Spend Efficiency (RSE) to evaluate the effectiveness of proposed mitigations relative to cost. As RSE is implemented, the project evaluation and selection process will mature to a process depicted in Figure 18 below. As RSE is implemented, refinements to the methodology and processes may be anticipated and are discussed below in the Risk Spend Efficiency (RSE) Model Refresh and Annual Mitigation Selection Planning Process initiatives.

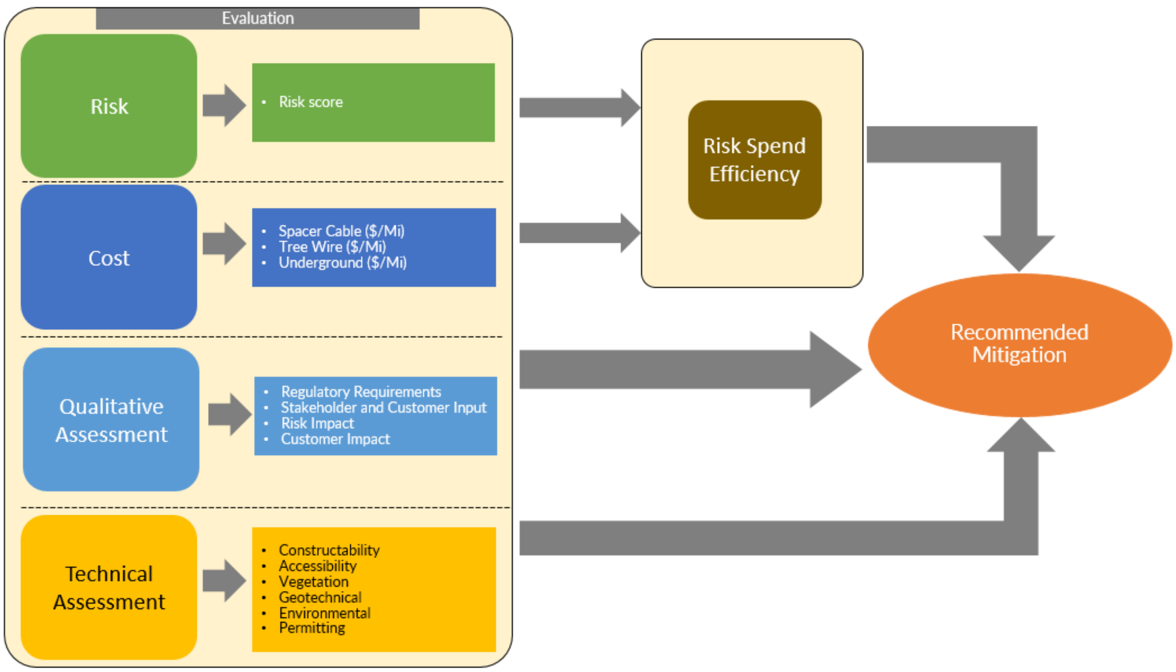


Figure 18: High Level Project Selection and Evaluation Process with RSE

The RSE calculation is shown in Figure 19 below.

$$RSE = \frac{\boxed{(\text{Risk Reduced})}}{\boxed{NPV(\text{Cost})}}$$

Where:

$$\boxed{\text{Risk Reduced}} = Risk_b - Risk_m$$

NPV = Net Present Value

$Risk_b$ = Baseline Risk (no mitigation)

$Risk_m$ = Mitigated Risk With Effectiveness

$\boxed{\text{Cost}}$ = Average Cost of Mitigation

Figure 19: RSE Calculation

Cost

For the initial evaluation of mitigation feasibility in the RSE calculation above, Pacific Power plans to use the average useful asset life and an average cost for select mitigations. These costs, shown in Table 7 below, are based on Pacific Power's average unloaded costs and the useful life is the time the asset is expected to be in service. It is expected that the average costs will change over time due to changes in project costs such as labor and materials.

Table 7: Average Cost and Years of Benefit of Select Mitigations

Mitigation	Estimated Years of Benefit	Cost	Cost Unit
Continuous monitoring sensors	10	$ 70,000	Circuit
Covered conductor (spacer cable)	50	$ 864,000	Mile
Covered conductor (tree wire)	50	$ 484,000	Mile
Covered conductor installation on distribution (all covered conductor)	50	$ 770,000	Mile

Mitigation	Estimated Years of Benefit	Cost	Cost Unit
Crossarm maintenance, repair, and replacement	30	$ 2,000	Pole
Distribution pole replacement and reinforcement, including with composite poles	30	$ 8,000	Pole
Expulsion fuse replacement	30	$ 2,000	Pole
Installation of system automation equipment (reclosers)	30	$ 250,000	Zone of Protection (ZOP)
Transmission pole replacement and reinforcement, including with composite poles	52	$ 25,000	Pole
Undergrounding of electric lines and/or equipment	50	$ 2,000,000	Mile

Effectiveness of a mitigation reflects if a mitigation is effective in preventing outages and the possibility of utility ignition resulting from an outage. Figure 20 below depicts the high-level inputs to the effectiveness calculation. As RSE is implemented and effectiveness measures identified for mitigations, Pacific Power expects to provide estimated risk reductions for projects such as those shown in Projects and validate the estimate with the actual results after the work is complete. Processes to track estimated and actual or effectiveness are in the scope of the Annual Mitigation Selection Planning Process areas for improvement discussed later in Section 1.4.

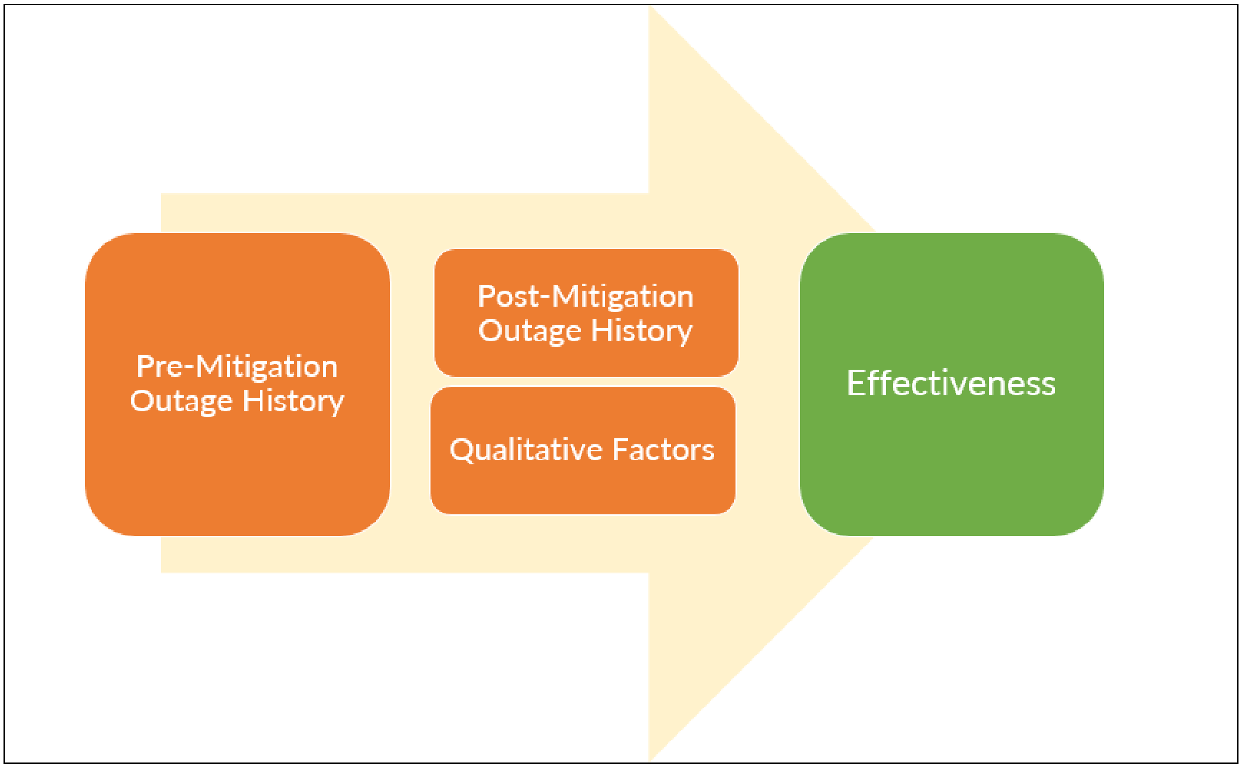


Figure 20: Mitigation Effectiveness Calculation Inputs

RSE Calculation Uncertainties and Limitations

While RSE is a useful approach to help assess the effectiveness of mitigations, it is important to highlight the uncertainties and limitations of the approach as discussed in Table 8 below. As Pacific Power implements RSE and builds a larger dataset of mitigations to measure baseline risk and post mitigation risk, it anticipates the uncertainties and limitations will evolve.

Table 8: Uncertainties and Limitations to RSE

Uncertainty/Limitation	Impact
Mitigation effectiveness can be difficult to ascertain absolutely; there are "noise" factors such as extreme weather years, EFR (Elevated Fire Risk) settings etc.	A program's effectiveness should be evaluated qualitatively with sufficient quantitative data such as outage and ignition information, an exact process is not established yet.

Uncertainty/Limitation	Impact
Effectiveness can differ for the same mitigation, influenced by varying such as local conditions, risk drivers, and baseline risk measures.	There may be a difference between the estimated effectiveness of a mitigation which is based on an average and the actual effectiveness at a specific location.
Initial measurement of effectiveness with a smaller dataset may not accurately reflect actual effectiveness.	Initial effectiveness calculations may be overly optimistic.
The impact of applying multiple mitigations at the same circuit could lead to an incorrect estimated risk reduction. For example, mitigation with 20% effectiveness and mitigation with 70% effectiveness does not necessarily result in a 90% risk reduction.	In the near term limits the ability to assess the impact of additional mitigations on reducing risk.
Useful lives of mitigations are average and may not reflect actual useful life.	The estimated life expectancy may be higher or lower than the average, impacting the effectiveness of mitigation.
Costs are average and do not consider the complexity of an implementation, such as terrain, permitting, etc.	The estimated RSE calculation may have a cost that is higher or lower than the actual cost of the mitigation.

PHASE 4 – IMPLEMENTATION AND MONITORING

As projects are selected, they move to the implementation and monitoring stage. Figure 21 below shows the high-level process described further below:

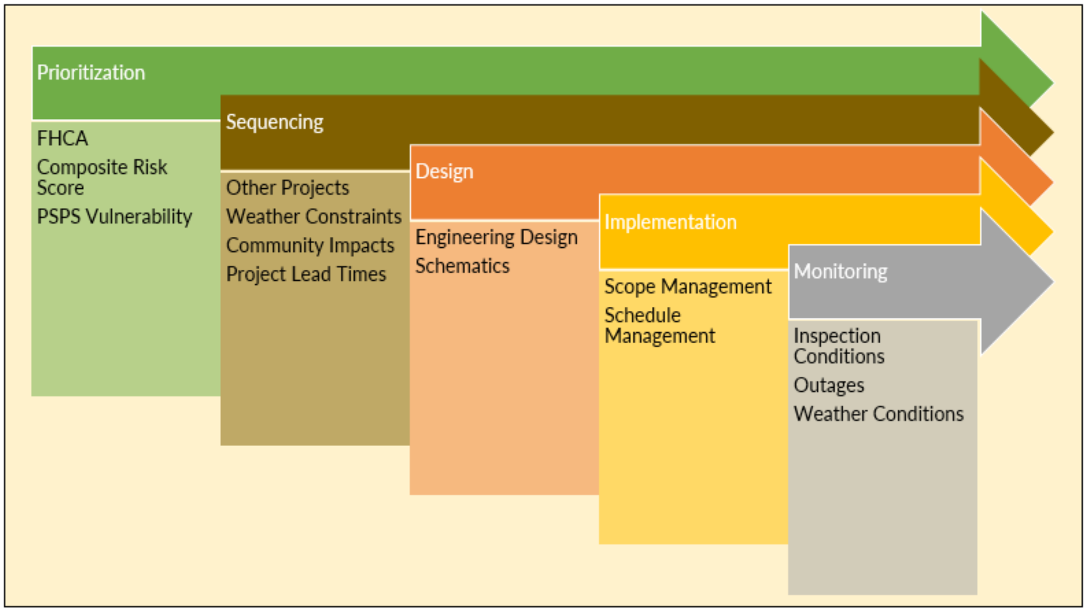


Figure 21: Project Implementation and Monitoring Process

Prioritization: Project work as shown in Appendix D will continue to be executed based on the current schedule. With the risk data provided by FireSight and the updated FHCA maps, Pacific Power will begin a transition to prioritizing new work based on the following:

1. Work inside the FHCA, in order from highest Fuel/Terrain Driven composite risk score to lowest.
2. Work outside the FHCA, in order from highest Fuel/Terrain Driven composite risk score to lowest.

Sequencing: After work is prioritized, it also must be sequenced to execute on the highest priority work first while understanding that constraints may impact when work can begin. Examples of constraints that impact sequencing include:

- Other utility work in the area. If proposed work requires electric service to be temporarily rerouted, other utility work in the area may impact when that can happen to manage service interruptions to customers.
- Weather conditions. For example, if the work is taking place in higher elevations, work may only be able to take place in summer and fall due to snow impacting roads. Summer work must be mindful of critical fire weather.

- Community impacts. This could range from municipal projects that have priority in a community to feedback from the local, state, and federal partners about timing to minimize impacts to residents.
- Project lead times such as ordering and receiving equipment and permitting.

Design: After the prioritization and sequencing has been determined, the project will move to the design stage. The design stage can take on many different forms depending on the project, ranging from schematics and process design to a complete engineering design. At this point, the project schedule and costs are finalized.

Implementation: Once the scope, prioritization, and design are completed, the project is ready to be implemented. Prior to implementation, key performance metrics will be established to enable measurement of results to inform mitigations' effectiveness for future modeling. Key metrics examples include installation dates, completion dates, conditions, and outages reported.

Monitoring: As the work is completed, the updated asset information will be updated annually in FireSight and over time the outage history for the asset will inform the composite risk score for the circuit to identify if the risk has been reduced and if the risk driver has been mitigated.

1.4. CONTINUOUS IMPROVEMENT

Through Pacific Power’s participation in formal regulatory proceedings, workshops, and multi-state and multi-utility collaborations, the Company has identified six areas for continued improvement from 2024-2027:

- Advanced Data Analytics Tool
- Fire Incident Root Cause Evaluations
- Refresh to Baseline Risk Mapping (FHCA Map Update)
- Annual Mitigation Selection Planning Process
- Risk Spend Efficiency (RSE) Model Refresh
- Evaluation of Climate Change Impacts on Wildfire Risk Modeling

ADVANCED DATA ANALYTICS TOOL

Efficient data analytics tools are the cornerstone of managing data to inform decisions. In 2023, Pacific Power began investing in data analytics software to begin evaluating the overall effectiveness of mitigation programs and validate risk modeling assumptions and outputs. For incident and risk event tracking, Pacific Power plans to enhance existing data collection processes and replace its existing data repository with an advanced data analytics platform to enable long-term trend analysis, inform project prioritization, and measure the effectiveness of mitigation programs. The data analytics tool will combine the various datasets described in Section 1.1 (fire incident information, utility asset information, and, where applicable, outage data) to create a comprehensive view of each tracked event. Actual fire incident data, including time, location, any affected equipment, and burn area size, is critical to validating modeled ignition risk and fire spread, update assumptions, and refine calculations. This information will be used to conduct long-term trend analysis of wildfire incidents near utility equipment to validate risk model assumptions and assess changes to risk drivers over time for inclusion in FireSight and PSPS risk modeling and mitigation planning. As seen in Figure 22 below, the Fire Incident Tracker is expected to be implemented in Q2 2024. with new features being added and prioritized in the development backlog as identified.

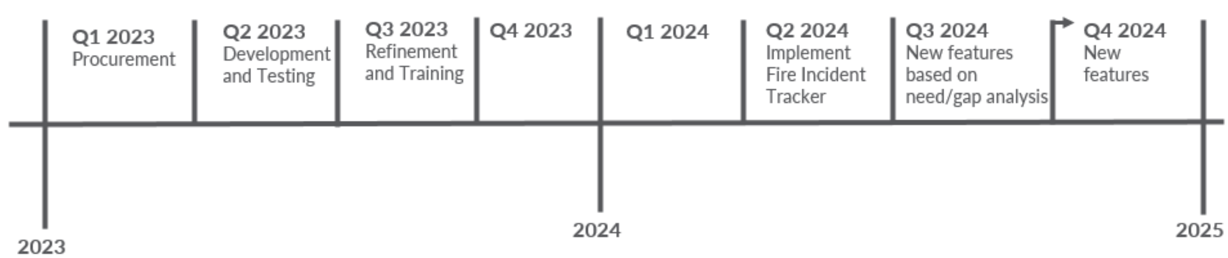


Figure 22: Advanced Data Analytics Project Timeline

FIRE INCIDENT ROOT CAUSE EVALUATION

After implementation of fire incident tracking in the Advanced Data Analytics Tool, Pacific Power plans to assess the processes regarding investigation of ignition incidents. At that time Pacific Power will consider updates, if necessary, as outlined below.

Figure 23 below shows the timeline to develop and implement the processes.

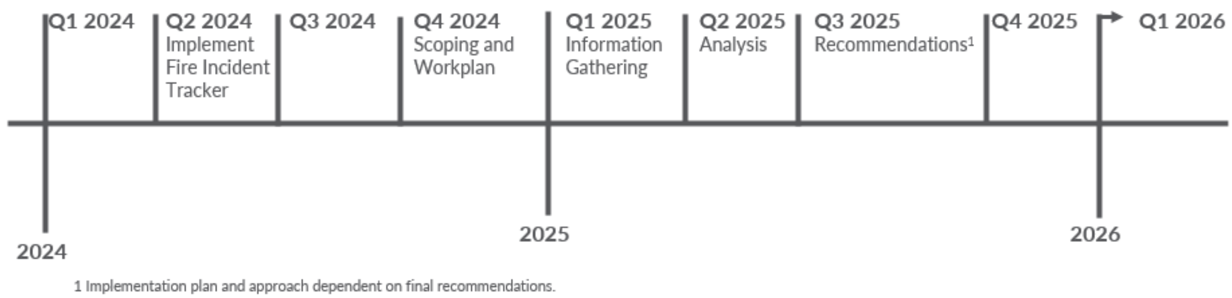


Figure 23: Fire Incident Root Cause Timeline

FHCA MAP UPDATE

As described in Section 1.2, Pacific Power evaluated the company's baseline wildfire risk and added new areas to the FHCA. In 2024, Pacific Power intends to continue its risk assessment evaluation and collect feedback from both internal and external stakeholders and experts. If appropriate, Pacific Power may further refine the FHCA boundaries for use in the 2025 Wildfire Mitigation Plan.

ANNUAL MITIGATION SELECTION PLANNING PROCESS

With the implementation of FireSight to identify highest risk circuits for mitigation and impending implementation of RSE the process to evaluate and select programs and projects will be updated to ensure that quantitative and qualitative assessment is well-integrated. This work will also implement processes to track results to support measurement of mitigation effectiveness and changes in risk levels at specific locations. This work will also consider if co-benefits should be integrated into mitigation assessment. Figure 24 below shows the initial timeline and deliverables for this process work.

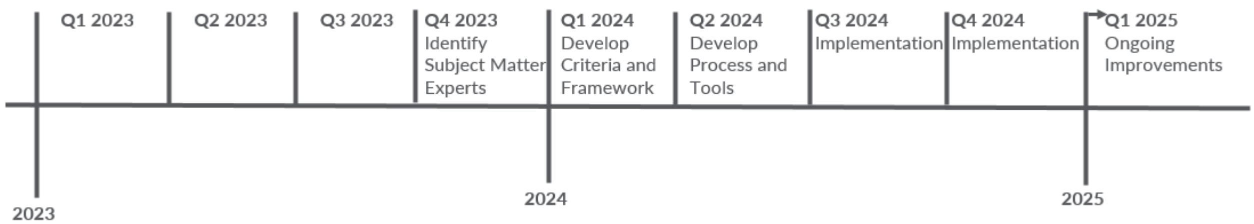


Figure 24: Annual Mitigation Selection Planning Process Timeline

RISK SPEND EFFICIENCY (RSE) MODEL REFRESH

As discussed in Risk Spend Efficiency, Pacific Power has started to implement Risk Spend Efficiency (RSE). The company anticipates developing and implementing an annual process to review and update mitigation effectiveness measures and identify if there are new mitigations that have sufficient data to implement effectiveness measures to evaluate projects. Pacific Power is also coordinating with other utilities to identify if there are opportunities to align RSE methodology, which may influence this work. The timeline is shown in Figure 25 below.

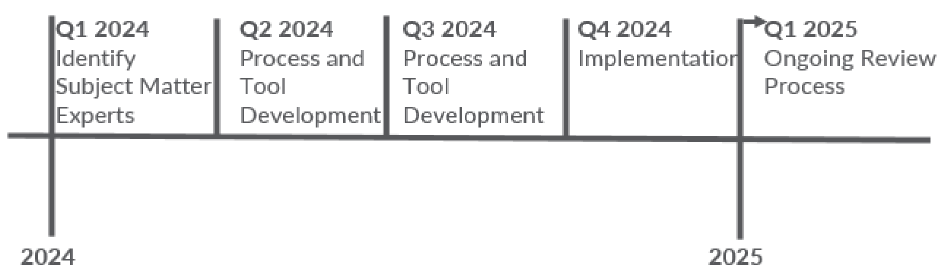


Figure 25: Risk Spend Efficiency Model Refresh Timeline

EVALUATION OF CLIMATE CHANGE IMPACTS ON WILDFIRE RISK MODELS

As discussed in above in “Consideration of Climate Change in Wildfire Risk Modeling”, Pacific Power will use learnings from the California OEIS workshops on climate change as an input to evaluating if there are additional risk variables that are impacted by climate change and the feasibility of integrating them into wildfire risk modeling. In addition to the OEIS workshops, Pacific Power plans to engage with internal subject matter experts and review research to identify how climate change may impact wildfire risk models and if any adjustments are needed to the models. The timeline in Figure 26 below may change based on the OEIS timeline and subject matter expert availability.

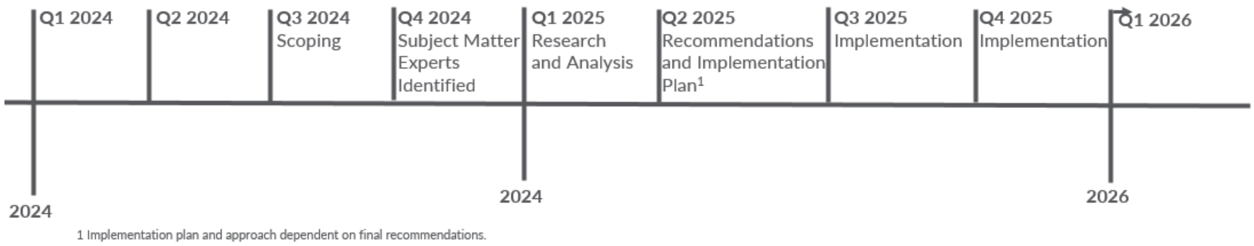


Figure 26: Evaluation of Climate Change Impacts Timeline

2. INSPECTION AND CORRECTION

Inspection and correction programs are tailored to identify conditions that could result in failure or a fault. These scenarios can arise when the infrastructure may no longer be able to operate as designed, including because of external factors such as weather conditions.

Pacific Power performs inspections on a routine basis as dictated by company policies that align with regulatory requirements as outlined in Figure 27 below.

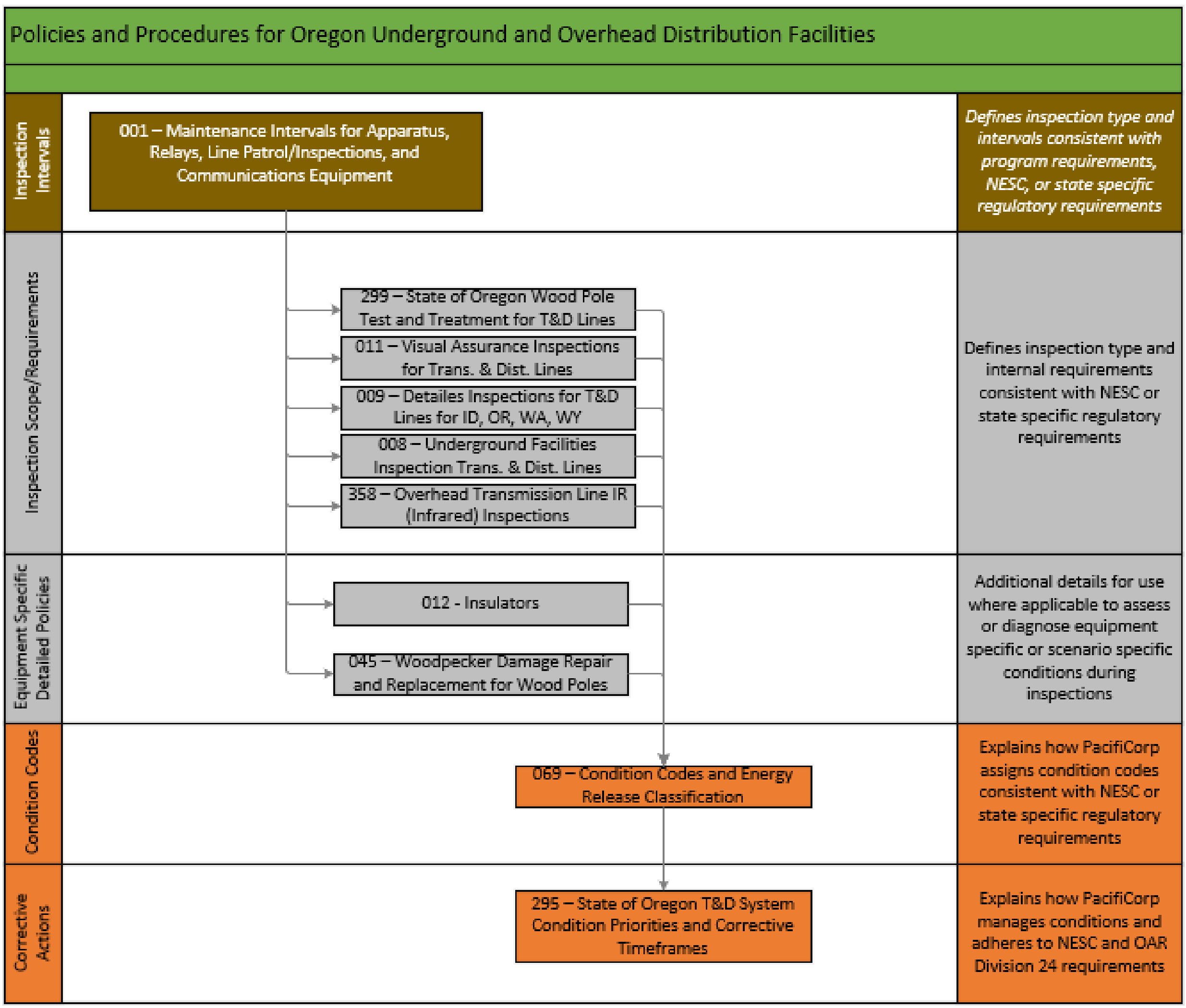


Figure 27: Inspections Policies and Procedures

When an inspection is performed on an asset, inspectors use a predetermined list of condition codes and priority levels (defined below) to describe any noteworthy observations or potential noncompliance discovered during the inspection. Once recorded, the condition codes are used to establish the scope of and timeline for corrective action to maintain conformance with National Electric Safety Code (NESC) requirements and company policies. This process is designed to correct conditions while reducing impact to normal operations.

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

- **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 clearance violations, 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.
- **Detailed Inspection:** A careful visual inspection accomplished by visiting each structure, as well as inspecting spans between structures. This inspection is intended to identify potential nonconformance with the NESC or company 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. Inspections may include pole-sounding, inspection hole drilling, and excavation to assess the pole condition at groundline to identify the need for any repair or replacement. When applicable, preservative treatment is also applied as part of this inspection.
- **Enhanced Inspection:** A supplemental inspection performed that exceeds the requirements of normal detailed or visual inspections; typically, a capture of infrared data.
- **Patrols:** Patrols are visual inspections performed in addition to scheduled inspection cycles during elevated fire risk conditions. Patrols can be performed prior or during significant weather events and are usually performed prior to re-

energization of lines in FHCA during fire season. Patrolling can result in conditions being identified and corrected like scheduled inspections. More details on patrolling activities are described in Section 0.

- **Condition:** The state of an asset regarding 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.
- **Energy Release Risk Condition:** A type of condition that, under certain circumstances, can correlate to increase the risk of a fault event and potential release of energy at the location of the condition.
- **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 or moderate risk to safety or reliability

2.1. STANDARD INSPECTION AND CORRECTION PROGRAMS

Pacific 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 Pacific Power asset management department. In general, visual assurance inspections are conducted more frequently, to quickly identify any obvious damage or defects that could affect safety or reliability. Detailed inspections have a more detailed scope of work, so they are performed less frequently than visual assurance inspections. 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. Regardless of the inspection type, any identified conditions are entered into a database for tracking purposes, which is Pacific Power's facility point inspection (FPI) system. For any condition identified, the inspector conducting the inspection will assign a condition code and the associated priority level. Corrections are then scheduled and completed within the correction timeframes established by Pacific Power asset management, as discussed below. While the same condition codes are used throughout Pacific Power's service territory, the timeframe for corrective action varies depending on location, wildfire risk area, and if the condition has the potential to release energy. In all cases, the timeline for corrections considers the priority level of any identified condition. Under the normal correction program, conditions are corrected within the following timeframes: an A priority condition which represents an "imminent" risk to safety or reliability is corrected immediately after discovery through repair, disconnection, or isolation; an A priority level condition is addressed within 30 days; and a B priority condition, 24 months. These correction timeframes are consistent with OAR 860-024-0012. Correction timeframes are accelerated for conditions in the FHCA, as discussed in greater detail below and consistent with OAR 860-024-0018.

2.2. FHCA 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 which, if uncorrected, could potentially ignite a fire. Consistent with the High Fire Risk Zone Safety Standards,[12] Pacific Power supplements the regular inspection and correction program in areas of elevated wildfire risk. Within the FHCA, the inspection and correction program includes: (1) a fire threat classification for specific condition codes which correlate to a heightened risk of fire ignition (energy

12 OAR 860-024-0018 High Fire Risk Zone Safety Standards, effective September 22, 2022, was created through Docket No. AR 638, Rulemaking for Risk-based Wildfire Protection Plans, and formalized in Order No. 22-335.

release risk); (2) more frequent inspections; and (3) expedited correction of any fire threat conditions. Table 9 below quantifies the number of incremental assets inspected in 2023.

Table 9: 2023 Incremental Asset Inspections

Inspection Type	OH Distribution FHCA	OH Transmission FHCA
Visual/Safety	47,322	10,092
Detailed	7,343	797
Enhanced (IR)	N/A	16,978

FIRE THREAT CONDITIONS

Certain conditions are classified as energy release risk conditions. As the name suggests, this category includes conditions which, under certain circumstances, can increase the risk of a fault event and potential release of energy at the location of the condition. Certain condition codes are categorically designated as an energy release risk. If a condition is designated as an energy release risk and the condition is located within the FHCA, the condition is designated as a fire threat condition, which means that the condition is treated as a type which corresponds to a heightened risk of fire ignition, as contemplated in OAR 860-024-0018(5). See Figure 28 below.

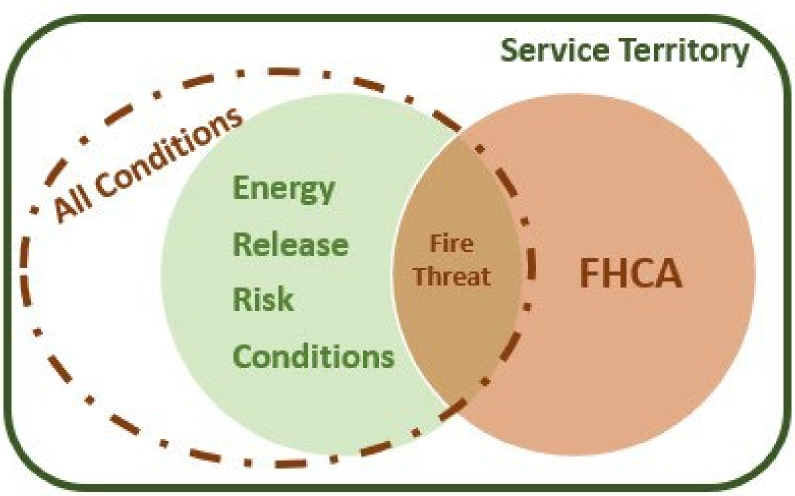


Figure 28: Fire Threat Condition Identification

Condition codes reflecting an appreciable risk of energy release are designated as energy release risk conditions. For example, a damaged or frayed primary conductor has a condition code CONDFRAY, which is designated as an energy release risk condition because the condition could eventually result in a release of energy under certain circumstances. CONDFRAY conditions identified within the FHCA are then designated as a fire threat condition because, due to escalation and environmental factors, the condition reflects a greater wildfire risk. In contrast, the observation of a missing or broken guy marker would result in the condition code GUYMARK, which is not designated as an energy release risk condition or a fire threat condition. Table 10 below describes the general types of energy release risk conditions designated by Pacific Power that, if located within the FHCA, correlate to a heightened risk of fire ignition, and then designated as fire threats.

Table 10: Energy Release Risk Conditions

Condition Type	Description
Broken / Missing Grounds	Broken or missing ground on a pole or equipment identified during visual or detail inspections.
Frayed Or Damaged Conductor	A conductor identified with damage/fraying on conductor strands because of visual or detail inspection
Infrared	Components or equipment that has a temperature rise that exceeds thresholds in company policy identified during enhanced inspection.
Improperly Installed Equipment/Hardware	Components or equipment that are installed or applied improperly and identified because of visual or detailed inspections.
Loose / Broken Anchors and Guys	Loose or broken anchor and guying identified on the pole as a result visual or detail inspections
Loose / Broken Communication Lashing Wires	One or more lashing wires (Telco, CATV, Fiber) that are broken or loose identified during visual or detail inspections

Condition Type	Description
Loose / Damaged Equipment (Capacitors, Regulators, Etc.)	Loose or damaged equipment (capacitors, regulators, reclosers, etc.) identified on the pole because of visual or detail inspections
Loose Connections / Bolts / Hardware	A connection, bolt, or hardware component identified that is loose or missing from equipment or framing on the pole because of visual or detail inspections
Pole Replacement	A pole identified for replacement because of intrusive testing or visual inspection that does not meet strength requirements / safety factors
Primary and Secondary Conductor Clearances	Primary and secondary conductor clearances from the pole, buildings, or ground that do not meet minimum clearance requirements specified in the NESC identified during visual or detail inspections
Unstable Soils	Soil or backfill on a pole that is unstable or insufficient identified during visual or detail inspections.
Vegetation Clearances	Vegetation clearances from the pole, primary/secondary conductor, and climbing space that do not meet minimum clearance requirements specified in the NESC identified during visual or detail inspections

INSPECTION FREQUENCY

Pacific Power conducts inspections on assets located within the FHCA more frequently than assets located outside of the FHCA. Consistent with industry best practices, inspections are the company's preferred mechanism to identify conditions. Pacific Power believes that performing more frequent inspections in the FHCA is a good mitigation strategy because more regular inspections should identify a certain percentage of conditions at an earlier stage. If conditions are identified at an earlier date, they will be corrected sooner. If a particular condition exists for a shorter amount of time, that condition is then less likely to cause a fault event or release energy, which could lead to a wildfire ignition. Inspection frequencies and average facility totals for Oregon's inspection programs are summarized in Table 11 below.

Table 11: Summarized Inspection Programs

Inspection Type	**Overhead Distribution and Local Transmission (Less than 200 kV)**			
	NON-FHCA 384,204 Total Facilities		**FHCA 60,251 Total Facilities**	
	Years	AVG Facilities/YR*	Years	AVG Facilities/YR*
Visual	2	192,102	1	60,251
Detailed	10	38,420	5	12,050
Pole Test & Treat	10	38,420	10	6,025
	Overhead Main Grid (More than 200kV)			
	NON-FHCA 10,155 Total Facilities		**FHCA 1,507 Total Facilities**	
	Years	AVG Facilities/YR*	Years	AVG Facilities/YR*
Visual	1	10,155	1	1,507
Detailed	2	5,078	2	754
Pole Test & Treat	10	1,016	10	151

EXPEDITED CORRECTION TIME PERIODS

Pacific Power will further mitigate wildfire risk by reducing the time for correction of fire threat conditions. As expressed above, certain types of conditions have been identified as having characteristics associated with a heightened risk of wildfire potential. Identified violations, recorded as energy release risk conditions, are on an accelerated correction schedule within the FHCA, as they are considered a heightened risk to safety or reliability. Additionally, any condition classified as imminent, regardless of location or condition designation are corrected immediately. All other fire threat conditions that correlate to a heightened risk of wildfire are required to be corrected within 180 days, aligned with requirements in OAR 860-024-0018(5)(b).[13] Correction timeframes for conditions are summarized in Table 12 below.

Table 12: Planned Correction Timeframes for Energy Release Conditions in the FHCA

Condition Priority	Correction Timeframes
Imminent Fire Threat conditions	Immediate
All other Fire Threat conditions within FHCA	Up to 180 days

FHCA INSPECTION AND CORRECTION PROGRAMS REASONING

In straightforward terms, Pacific Power believes that performing more frequent inspections is a good mitigation strategy as more frequent inspections should, by nature, identify a certain percentage of conditions at an earlier stage than they would have otherwise been identified with less frequent inspections. If conditions are identified at an earlier date, they will, by practice and consistent with Division 24 rules, be corrected at an earlier date. And if a particular condition exists for a shorter amount of time, that condition is then less likely to cause a fault event or energy release, which could lead to a wildfire ignition.

When initiated in 2020, Pacific Power applied general operations judgement and leveraged experience in other states to decide that a five-year cycle for detailed inspections on distribution circuits and local transmission would be appropriate. Under Division 24 rules the detailed inspections are required to be completed on a ten-year cycle, but the company determined the five-year inspection cycle was warranted in areas of elevated wildfire risk. Pacific Power also notes, however, that OAR 860-024-0011(1)(b)(A)

[13] OAR 860-024-0018(5)(b) requires that "Any violation which correlates to a heightened risk of fire ignition shall be corrected no later than 180 days after discovery unless an occupant receives notification under OAR 860-028-0120(6) that the violation must be corrected in less than 180 days to alleviate a significant safety risk to any operator's employees or a potential risk to the general public."

treats ten years as a "maximum interval," so more frequent intervals are consistent with that rule.

Since implementation of the new inspection frequencies in 2020, Pacific Power has identified more energy release conditions per year. By reducing the inspection cycle from a 10-year cycle to a 5-year cycle the number of structures inspected on average has doubled. The number of conditions identified has also roughly doubled in comparison leading to the conclusion that the reduced inspection frequency has provided the identification of 50% more conditions earlier then if the longer inspection cycle had remained. The average differences are noted in Table 13 below.

Table 13: Average Energy Release Conditions Identified & Corrected per Year

Average per Year	Prior to 2020	Post Changes
Structures Inspected (AVG per year)	7,300	12,900
Energy Release Conditions Identified (AVG per year)	700 Conditions	1,584 Conditions
Energy Release Conditions Corrected (AVG per year)	590 Conditions	1,280 Conditions

In 2024, Pacific Power plans to continue performing inspections more often in the FHCA to continue mitigating wildfire risk. With the implementation of new risk assessments and data analytics tools, Pacific Power intends to evaluate how new datasets can inform inspection and correction programs. For example, if the data were to demonstrate that certain types of equipment correlated to greater risk, this information could inform inspection requirements, condition types, and condition correction priorities. Additionally, Pacific Power will continue collaborating with other Investor-Owned Utilities (IOUs) and share information regarding inspection programs and outcomes.

2.3. FOREIGN OWNED FIRE THREAT CONDITIONS

As a part of the inspection programs described above where conditions are identified for correction, the company may also identify conditions associated with foreign owned equipment or poles that pose a potential heightened risk of wildfire. For example, a foreign owned anchor observed to be broken or loose can potentially impact the structural integrity of a pole supporting Pacific Power owned electrical equipment, posing a heightened risk of wildfire. Additionally, foreign owned lose or broken bolts and hardware necessary to secure foreign owned equipment to Pacific Power owned poles can also pose a heightened risk of wildfire. As a part of the same programs described above, these conditions are collected and categorized into Energy Release Risk conditions. When these Energy Release Risk conditions are located within the FHCA, these conditions are further categorized as fire threat conditions. Table 14 below describes both the subset of potential Energy Release Risk conditions that can be associated with foreign owned equipment or assets and correlate to a heightened risk of fire ignition when located within the FHCA as well as the number of fire threat conditions identified through inspections in 2023.

Table 14: Foreign Owned Energy Release, Fire Threat Risk Conditions

Condition Type	Description	2023 Foreign Owned Conditions
Lashing Wire	Loose or broken lashing wire identified on the pole because of visual or detail inspections	0
Loose / Broken Anchors and Guys	Loose or broken anchor and guying identified on the pole because of visual or detail inspections	1
Loose Connections / Bolts / Hardware	A connection, bolt, or hardware component identified that is loose or missing from equipment or framing on the pole because of visual or detail inspections	0
Pole Replacement	A pole identified for replacement because of intrusive testing or visual inspection that does not meet strength requirements / safety factors	4

Pacific Power uses the processes under OAR 860-024-0018 to either correct, request correction of, or escalate unresolved correction of these energy release conditions associated with foreign owned equipment and assets in FHCA areas in Oregon.

Notification. For such conditions on Pacific Power owned poles, notifications are communicated to attaching entities based upon Pacific Power attachment records. For such conditions on foreign owned poles, notifications are communicated to the foreign pole owners based upon Pacific Power's pole ownership records. These notifications include a description of the condition in question, location information, correction timeframes required under the OAR, and next steps available to Pacific Power under the OAR in the event the notified party does not take action to correct the conditions.

Correction. Consistent with OAR 860-024-0018 and the correction of electric utility related energy release conditions, Table 15 following describes the required timelines associated with correction of foreign owned asset related energy release conditions.

Table 15: Energy Release Condition Correction Timeframes for Foreign Owned Equipment & Assets

Condition Priority	Correction Timeframes
Imminent Energy Release conditions	Immediate
All other Energy Release conditions within FHCA	Up to 180 days

Pacific Power requires correction of energy release conditions associated with foreign owned equipment and assets consistent with these timeframes. Where the equipment or asset owner is unresponsive, Pacific Power may correct some conditions on behalf of the owner to mitigate wildfire risk and charge the pole owner or equipment owner a replacement fee of 25% of the total amount of work.[14]

Escalation. On identified foreign owned conditions, if Pacific Power does not make the repair and the notified party has not fulfilled its obligations to correct the condition, Pacific Power will assemble the necessary documentation required for filing a complaint under

14 See OAR 860-024-0018(6) which states "If the pole owner or equipment owner does not replace the reject pole or repair the equipment within the timeframe set forth in the notice, then the Operator of electric facilities may repair the equipment or replace the pole and seek reimbursement of all work related to correction or replacement of the reject pole or equipment including, but not limited to, administrative and labor costs related to the inspection, permitting, and replacement of the reject pole. The Operator of electric facilities is also authorized to charge the pole owner or equipment owner a replacement fee of 25 percent of the total amount of work."

OAR 860-024-0061, fill out the requisite form and file the complaint with the commission. If Pacific Power performs the correction of the condition after first providing the notified party the requisite opportunity to correct the condition, Pacific Power will invoice the notified party in accordance with the OAR. If the invoiced party does not pay the invoice, Pacific Power may file a complaint with the commission in accordance with the OAR, to compel payment.

2.4. ENHANCED INSPECTIONS

Pacific Power's enhanced inspection programs use alternate technologies such as infrared or drone imagery to supplement visual inspections. identify hot spots, equipment degradation, and potentially substandard connections. The infrared inspection may identify hot spots which could be a potential issue not visible through other inspection programs. The drone inspections can provide enhanced imagery, alternate perspectives, and the ability to package new technology (e.g., LiDAR, IR, and detailed imagery) to view assets and assess conditions.

INFRARED INSPECTION PROGRAM

The transmission infrared inspection program is performed using a helicopter flying over designated lines within the service territory near peak loading intervals and is performed incrementally to existing inspection programs. Hot spots on power lines identified through infrared data gathering can be indicative of loose connections, deterioration and/or potential future energy release locations. Therefore, identification and removal of hot spots on overhead transmission lines can reduce the potential for equipment failure and faults and mitigate the risk of ignition.

Identified Lines. Beginning in 2021 and described in Pacific Power's 2022 Oregon WMP, the company performs enhanced inspections annually on overhead transmission lines operating at 69kV or above that are within or are interconnected with the FHCA. This scope includes areas in Southern Oregon, Hood River, and Enterprise totaling 35 line-segments and approximately 1,000 line-miles. Based on successes experienced in Oregon as well as multiple years of experience in other states, the scope has expanded to all overhead transmission lines throughout Oregon which includes an additional 2,000 line-miles on 116 line-segments. A map, as shown in Figure 29, illustrates the transmission lines that are currently inspected and planned for enhanced inspections.

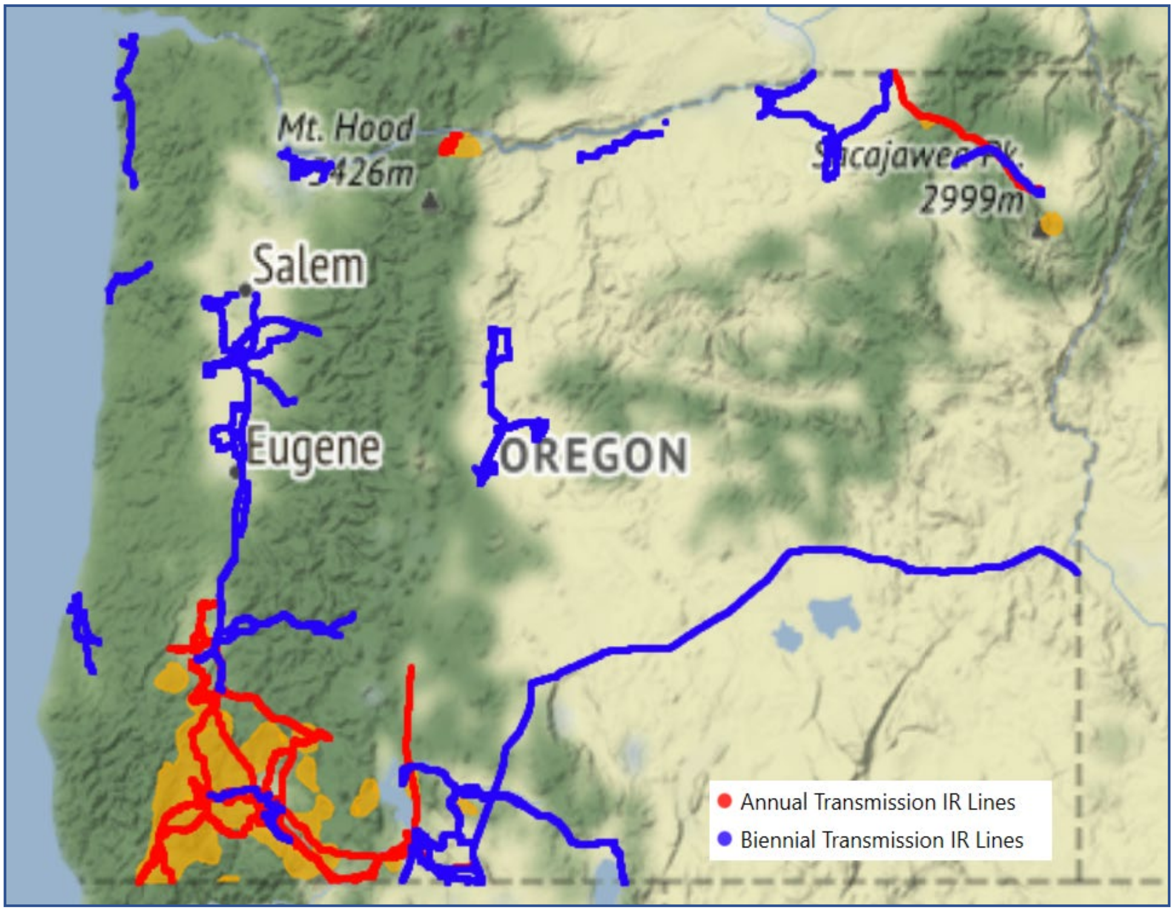


Figure 29: Map of Enhanced Transmission Line Inspections

Inspection Frequency. Pacific Power varies inspection frequency between circuits in the FHCA and non-FHCA areas as described in Section 2.2. Assets located within FHCA areas are considered to have a heightened risk of wildfire. Therefore, enhanced inspections on overhead transmission lines, within or interconnected with the FHCA, are performed annually. Additionally, enhanced inspections are being performed outside of the FHCA areas on a biennial basis. As described previously, these frequency intervals were determined based on successes that have been experienced in Oregon as well as multiple years of experience in other states. Enhanced inspection frequencies are summarized in in Table 16 below.

Table 16: Summary of Enhanced Inspection Frequency on Transmission Lines

	Frequency	Line Miles
FHCA	Annually	1,000
Non-FHCA	Biennially	2,000

Inspection Intervals/Bundling. Different than patrol or detailed inspections, IR inspections are performed by a trained thermographer assisted by a qualified transmission line patrolman, where lines are "bundled" depending on peak loading events. In general, peak loading events are seasonal between winter, spring, and summer. Inspections performed during peak loading supports the highest probability of detecting abnormal thermal rises on equipment induced by system loading.

Corrective Action. Like other inspection and correction programs, Pacific Power assesses the condition severity and follows the general process as described in Section 2.2 to set the correction timeframe. Findings are separated into three severity ranges depending on the measured temperature rise over anticipated conditions, a general assessment, and recommendation from the trained thermographer.

INFRARED INSPECTION & CORRECTION REASONING

When Pacific Power implemented its enhanced infrared inspection program, the company applied general operations judgment and leveraged experience in other states to determine whether an annual enhanced inspection was warranted in areas with heightened wildfire risk. Additionally, new conditions have been identified during each year of the program, indicating that an annual enhanced inspection can incrementally mitigate risk.

Pacific Power has identified 16 incremental conditions for correction in Oregon in 2023 and total of 31 throughout the infrared inspection program which were not identified through the other inspection programs (see Table 17 below). In general, conditions identified for correction were on splices and jumper connections. Specific results in each year can vary due to the assets being inspected, environmental factors during data collection, and maturation of the program, each incremental condition identified and corrected represents an incremental reduction in risk.

Table 17: Incremental Conditions Identified through Enhanced Infrared Inspections

Inspection Year	Incremental Conditions	Miles Inspected	Conditions Found per Mile Inspected
2023	16 Conditions	~2,000mi	1/125
2022	10 Conditions	~1,000mi	1/108
2021	5 Conditions	~1,000mi	1/200
3 YR Program Total	**31 Conditions**		

The comparison image in Figure 30 below demonstrates the ability of infrared technology to detect a condition not visible in the photograph.

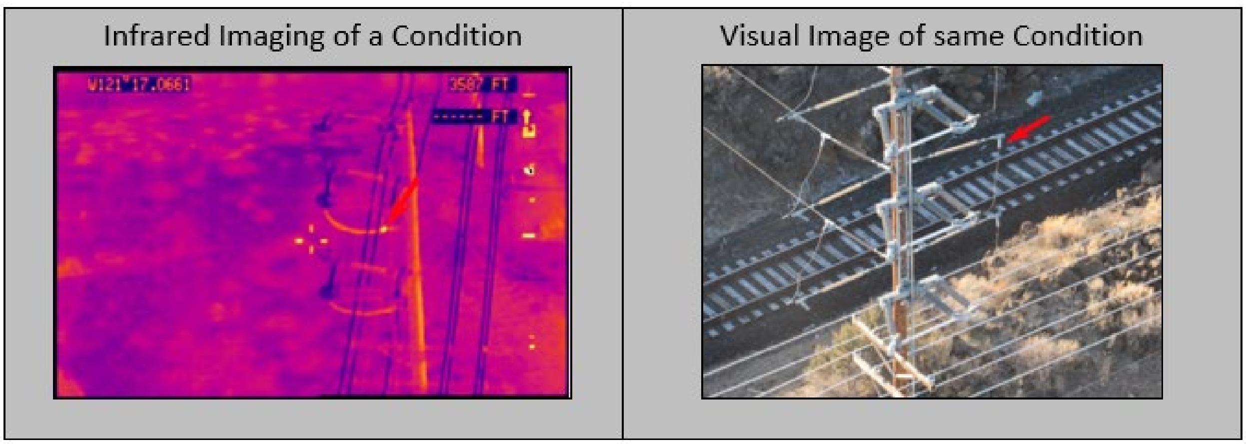


Figure 30: Infrared Inspection Compared to Visual Image

DRONE INSPECTION PILOT

When leveraged to perform supplemental asset inspections, drones can provide enhanced imagery, alternate perspectives, and the ability to package new technology (e.g., LiDAR, IR, and detailed imagery) to view assets and assess conditions. See example of enhanced imagery below in Figure 31.

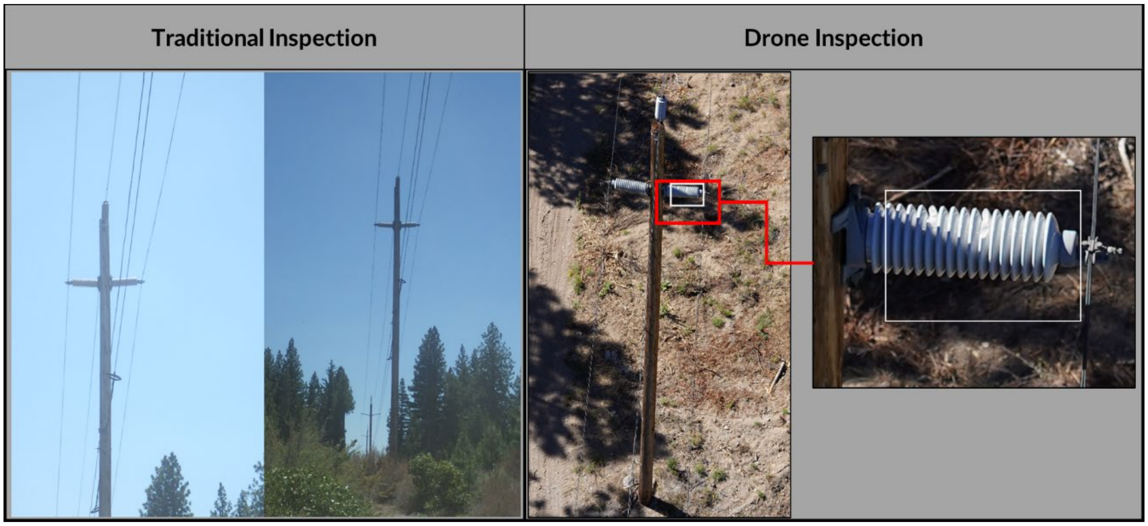


Figure 31: Traditional Visual Inspection Compared to Drone Inspection

Recently, Pacific Power leveraged drones to complete a pilot inspection of rural, hard to access transmission assets in CA that was successful in identifying incremental conditions and providing insight into new technology that could be utilized for asset inspections. Building upon these initial, positive results, Pacific Power intends to implement a pilot project in Oregon. While still being finalized, the company anticipates completing incremental drone inspections on some of the company's overhead assets in 2024.

2.5. INSPECTION QA/QC

Pacific Power's asset QA/QC centers around a field audit of 5% of all inspected facilities each year to assess inspection completeness and condition categorization accuracy. Where a trend or observation emerges, the audit results are reviewed with the inspectors and program managers at the following year's annual pre-inspection program meeting typically held during the first quarter of each year. At this meeting, inspectors, inspection support staff, and program managers discuss the previous year's accomplishments, modifications or updates to inspection policies or procedures, and finalize the inspection plan for the subsequent year's work. To enhance data quality, Pacific Power also leverages electronic tools to capture inspection and condition records. The electronic tools use drop-down menus for standardization of data capture, facilitate automatic processing into the company's system of record reducing the potential for human error, and enable streamlined data reviews and analytics.

3. VEGETATION MANAGEMENT

Pacific Power's vegetation management program is designed to reduce the potential of vegetation contact with power lines, which reduces the potential of an ignition originating from electrical facilities. While it is impossible to eliminate all vegetation contact, at least without radically altering the landscape near power lines, a primary objective of the vegetation management program is to minimize contact by addressing both grow-in and fall-in risks. Pacific Power manages a comprehensive vegetation management program throughout Pacific Power's territory. All the work performed in the core program provides wildfire mitigation, because the core program is designed to minimize the risk of vegetation contact. In addition, Pacific Power supplements the core program with heightened activities both inside and outside of the FHCA, further reducing the potential of vegetation contact in those areas.

3.1. REGULAR VEGETATION MANAGEMENT PROGRAM

Tall growing vegetation is pruned to maintain a safe distance between vegetation and power lines. Dead, dying, diseased, or otherwise impacted trees or vegetation, which are at an elevated risk of falling into a power line, are removed. Like other utilities, Pacific Power contracts with vegetation management service providers to perform the pruning and tree removal work for both transmission and distribution lines.

Figure 32: Hazard Tree Removal

DISTRIBUTION

Vegetation near distribution facilities is pruned to maintain a clearance between conductors and vegetation. Vegetation work is performed on a regular cycle. When cycle work is planned, the circuit is inspected to identify vegetation that needs to be pruned because it may grow too close to power lines before the next scheduled cycle work. When vegetation is identified for pruning, it is pruned to achieve minimum post-work clearance distances, designed to maintain a sufficient clearance until the next scheduled cycle work. Tree growth rates influence the minimum post-work clearance distance. For example, faster growing trees need a greater minimum post-work clearance to maintain required clearance throughout the cycle. Pacific Power also integrates spatial concepts to distinguish between side clearances, under clearances, and overhang clearances. The distances for the minimum post-work clearances used for normal cycle maintenance are listed in Table 18.

Table 18: Normal Distribution Minimum Post-Work Vegetation Clearance Distances

	Slow Growing (<1 ft/yr.)	Moderate Growing (1-3 ft/yr.)	Fast Growing (> 3 ft./yr.)
Side Clearance	8 ft.	10 ft.	14 ft.
Under Clearance	10 ft.	14 ft.	16 ft.
Overhang Clearance	12 ft.	14 ft.	14 ft.

Figure 33: High-Risk Tree Removal

Pacific Power also removes high-risk trees as part of distribution cycle work, to minimize fall-in risk. High-risk trees are dead, dying, diseased, deformed, or unstable trees which have a high probability of falling and contacting a substation, distribution conductor, transmission conductor, structure, guys, or other electric facility. High-risk trees pose a safety and reliability risk and are, therefore, removed. High-risk trees are identified for removal in any vegetation inspection. To identify high-risk trees, the inspector applies the best management practices set forth in ANSI A300 (Part 9).

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

Vegetation management on distribution circuits in Oregon outside of the Portland metropolitan area was historically completed on a four-year cycle (with interim work performed where warranted). In 2022, Pacific Power adopted a three-year cycle for all distribution cycle work in Oregon. Through this transition Pacific Power is completing additional vegetation management inspection and correction activities on circuits that are “off-schedule” (i.e., circuits that were scheduled for work on the four-year cycle now fall within a later calendar year within the three-year cycle). This additional work related to the cycle transition is expected to continue through 2024 at a minimum. As a result, incremental costs associated with the transition to a three-year cycle are included throughout 2024 but are anticipated to decrease slightly after 2023.

TRANSMISSION

Vegetation management on transmission lines is also focused on maintaining clearances between vegetation and electrical facilities, which vary according to the voltage of the transmission line. At all times, Pacific Power must maintain the required minimum clearances set forth in FAC-003-04,[15] are referred to as the “Minimum Vegetation Clearance Distance” (MVCD). To determine whether work is needed, an action threshold distance is applied, meaning that work is required if vegetation has grown within the action threshold distance. When work is completed, vegetation is cleared, at a minimum, to a minimum post-work clearance distance. The applicable distances for various voltages of transmission lines are shown in Table 19.

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

Table 19: Transmission Minimum Vegetation Clearance (in Feet) by Line Voltage

Minimum Clearance Type	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

In some circumstances, when local conditions and property rights allow, Pacific Power may use "Integrated Vegetation Management" (IVM) practices to prevent vegetation growth from violating clearances by proactively managing the species of trees and other vegetation growing in the right-of-way. Under such an approach, Pacific Power may remove tree species that could potentially threaten clearance requirements, while encouraging low-growing cover vegetation, which would never bring about clearance issues.

Main grid transmission lines are inspected annually. Other transmission lines ("local" transmission) are inspected as needed. Vegetation work is scheduled dependent on several local factors, consistent with industry standards and best management practices. When transmission lines are overbuilt, meaning they are located on the same poles as distribution lines, vegetation management work is completed on the normal distribution cycle schedule.

TRANSMISSION DISTRIBUTION

Figure 34: Example Right of Way Clearances for Transmission (left) and Distribution (right)

POST-WORK AUDITS

After work is completed, whether on distribution or transmission, Pacific Power conducts post-audits (quality control reviews) to compare completed work against required specifications. Post-audits are conducted after the vegetation management work is completed at a location, typically as soon as reasonably practicable to arrange for prompt corrective work if any exceptions are identified. Pacific Power targets to perform a full post-work audit on distribution cycle and correction work associated with the distribution annual vegetation inspection program.

3.2. FHCA VEGETATION MANAGEMENT

In addition to the regular vegetation maintenance program discussed above, Pacific Power's vegetation management specifically targets risk reduction in the FHCA with three distinct strategies. First, annual vegetation inspections are conducted by vegetation management on all lines in the FHCA, with correction work also completed based on inspection results. Second, increased minimum clearance distances are used for distribution cycle work completed in the FHCA. Third, annual pole clearing is conducted within the FHCA on subject equipment poles which are defined as poles having switches, clamps, fuses, or other devices that could create a spark.

ANNUAL FHCA VEGETATION INSPECTION

Pacific Power annual vegetation inspection program is designed to identify and complete vegetation management work outside of the normal cycle maintenance program. If a circuit in the FHCA is not scheduled for cycle maintenance in a particular year, the circuit (or the portion of the circuit in the FHCA) will be scheduled for an annual vegetation inspection. An annual inspection is typically scheduled with the goal to complete the inspection prior to the height of fire season. An inspector conducting an annual inspection will identify vegetation likely to exceed minimum clearance requirements prior to the next scheduled inspection, including any high-risk trees. After an annual inspection is completed, vegetation management work is promptly completed as reasonably practicable, including removal of any high-risk trees.

EXTENDED CLEARANCES

Pacific Power uses increased minimum post-work clearance specifications distances for any distribution cycle work in the FHCA. In simple terms, more clearance equates to less chance of a contact. These minimum post-work clearance distances require pruning to at least 12 feet, in all directions and for all types of trees by increasing the minimum distance required at the time pruning is done, Pacific Power further minimizes the potential of vegetation contacting a power line at any time. The minimum clearance distances for the FHCA are listed in Table .

Table 20: Distribution Minimum Vegetation Clearance Specifications in the FHCA

	Slow Growing (<1 ft./yr.)	Moderate Growing (1-3 ft./yr.)	Fast Growing (>3ft./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.

POLE CLEARING

Pacific Power vegetation management performs pole clearing on subject equipment poles located in the FHCA. Pole clearing involves removing all vegetation within a ten-foot radius cylinder (up to eight feet vertically) of clear space around a subject pole and applying herbicides and/or soil sterilant to prevent any vegetation regrowth (unless prohibited by law or the property owner), as illustrated in Figure 35.

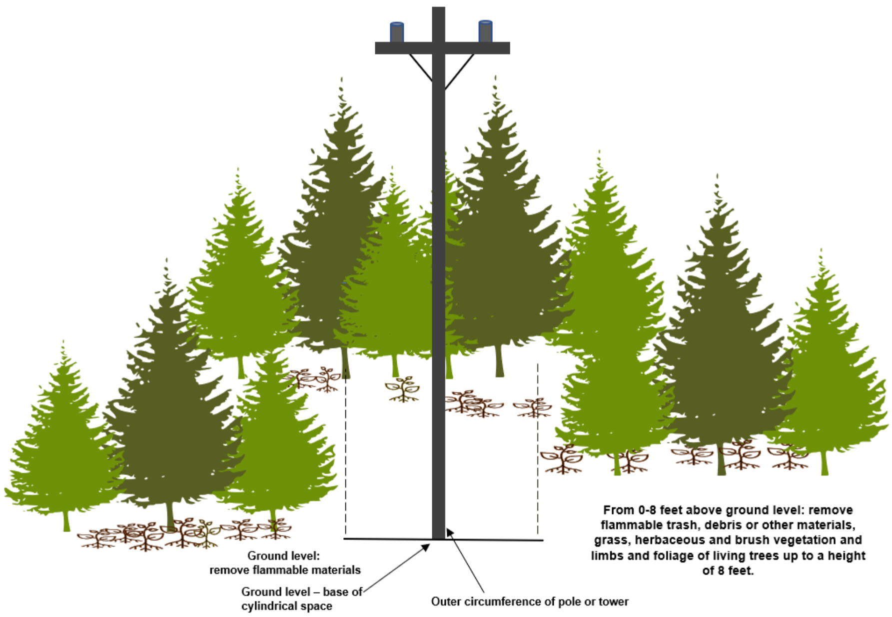

Figure 35: Pole Clearing Strategy

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 remove fuels at the base of equipment poles, 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.

Figure 36: Pole Clearing at Pole Base

4. SYSTEM HARDENING

Pacific Power's electrical infrastructure is engineered, designed, and operated in a manner consistent with utilities best practice, enabling the delivery of safe, reliable power to all customers. When installing new assets as a part of corrective maintenance or growth projects, Pacific Power incorporates the latest technology and engineered solutions that have been assessed and proven to be effective. When conditions warrant, Pacific Power engages in strategic system hardening, like replacing or modifying existing assets and/ or utilizing a new design or technology to make the asset more resilient. With the growing risk of wildfires, the company supplements existing asset replacement projects with system hardening programs designed to mitigate 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 or be subject to an existing wildfire event. 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 or reduce the impact of an existing wildfire on utility infrastructure. System hardening programs represent the greatest long-term mitigation tool available for use by electric utilities. The phasing and prioritization of such programs, as described in Section 1.3, will utilize risk modeling and assessments for program identification which will be evaluated for implementation as a strategic hardening initiative.

No single system hardening program mitigates all wildfire risk related to all types of equipment. Individual programs address several 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 a particular design or equipment elements, these programs can also consider environmental factors impacting the magnitude of a wildfire. Extreme weather conditions such as dry and windy conditions, present an increased risk of wildfire ignitions and spread. Consequently, system hardening programs may specifically attempt to reduce the potential of an ignition event when it is dry and windy, by utilizing equipment that is less likely to release energy if failure or contact with foreign objects occur.

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, Pacific Power cannot guarantee that a spark or heat coming from equipment owned and operated by the company will never ignite a wildfire. Instead, the system hardening efforts seek to reduce the potential of an ignition associated with any electrical equipment by making investments with targeted system hardening programs.

4.1. LINE REBUILD PROGRAM

Circuits within the FHCA constructed with bare overhead wire have been evaluated for potential system hardening work. As a part of this program, certain overhead lines may either be moved, removed, retrofitted with more resilient materials such as covered conductor or non-wooden poles, or converted to underground. After completion of system hardening, such lines will be more tolerant to incidental contact, thereby reducing the risk of wildfire.

COVERED CONDUCTOR

Historically, most distribution power lines in the United States – and in Pacific Power's service territory – were installed with bare overhead conductor. As the name "bare" suggests, the wire surface is uninsulated and exposed to the elements. For purposes of wildfire mitigation, covered conductor which can also be called tree wire or aerial spacer cable, has been installed to provide an insulating layer around the conductor.

The dominant characteristic of covered conductor is manufactured with multiple high-impact resistant extruded layers forming an insulation around stranded hard drawn conductor. The inherent design provides insulation for the energized metal conductor. As a comparison, covered conductor is like an extension power cord that might be used in a garage. To be clear, covered conductor is not insulated enough for people to directly handle an energized high voltage power line (as discussed below). The insulating layers reduce the risk of wildfire by minimizing the potential of vegetation or ground contact with the conductor.

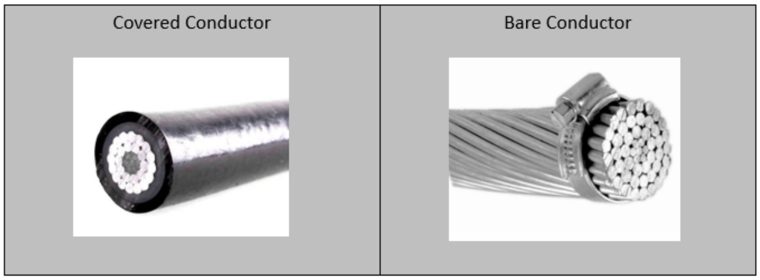

Figure 37: Covered Conductor Compared (left) to Bare Conductor (right)
Images from VW Wire and Cable Product List

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 have improved covered conductor products, reducing the operating constraints historically associated with the design. These advances have improved the durability of the product and reduced the impact of conductor thermal constraints. There are still logistical challenges with covered conductor. The wire is heavier, especially during heavy snow/ice loading, meaning that more and/or stronger poles may be required to support covered conductor.

The wildfire mitigation benefits of covered conductor are significant. As discussed in the risk assessment in Section 1, a disruption on the electrical network, a fault, can result in emission of a spark or heat that could be a potential source of ignition. Covered conductor reduces the potential of many kinds of faults. For example, contact from an object is a major category of real-world faults which can cause a spark. Whether it is a tree branch falling into a line and pushing two phases together or a Mylar balloon carried by the wind drifting into a line, contact with energized bare conductor can cause 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 reduces the risk of ignition associated with most types of equipment failure. For example, if a cross arm breaks, the wire held up by the cross arm 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 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 linked with the worst wildfire events. Dry and windy conditions increase the wildfire risks. Wind is the primary driving force behind 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 an 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.

UNDERGROUND

Pacific Power also continues to evaluate the potential to convert overhead lines to underground lines for the rebuild projects. The potential wildfire mitigation benefits are undeniable. While an underground design does not eliminate every ignition potential (i.e., because of above-ground junctions), it is the most effective design to reduce the risk of a utility-related ignition. Currently, the cost and operational constraints of underground construction often make it difficult to apply on a widespread basis. Nonetheless, some electric utilities are planning to employ an underground strategy more broadly.

Currently, Pacific Power is continuing to evaluate the use of underground design as part of the rebuild program on a project-by-project basis; and it uses under-grounding where practical. Through the design process, every rebuild project is assessed to determine whether sections of the rebuild should be completed with underground construction. Some communities and landowners may prefer, for aesthetic reasons, to pursue a higher cost underground alternative. Consistent with electric service regulations and company design standards, Pacific Power will collaborate with communities or individual landowners who are willing to pay the incremental cost and obtain the necessary legal entitlements for underground construction.

NON-WOODEN POLES

Traditionally, overhead poles are replaced or reinforced within the service territory consistent with the NESC, company policies, and prudent utility practice. When a pole is identified for replacement, typically through routine inspections and testing, major weather events, or joint use accommodation projects, a new pole consistent with engineering specifications suitable for the intended use and design is installed in its place. Engineering specifications typically reflect the use of wooden poles which is consistent with prudent utility practice as they are considered safe and structurally sufficient to support overhead electrical facilities during standard operating conditions. However, the use of alternate non-wooden construction, such as steel or fiberglass, can provide additional structural resilience in high-risk locations during wildfire events and, therefore, aid in restoration efforts. For example, as a part of covered conductor installation, the strength of existing poles is evaluated. In many cases, the strength of existing poles may not be sufficient to accommodate the additional weight of covered conductor. In these instances,

Figure 38: Distribution Fiberglass Poles

the existing wooden pole is upgraded to support the increased strength requirements and replaced with a non-wooden solution for added resilience.

LINE REBUILD SUMMARY

At the time of document preparation, Pacific Power is forecasting successful construction of 80 miles[16] of covered conductor by the end of 2023. Additionally, Pacific Power initiated engineering and design of approximately 125 miles of covered conductor for construction in 2024. Unlike many distribution construction projects, the use of covered conductor often requires a custom engineered design for each project. Additionally large-scale line rebuild projects, overhead and undergrounding, require long lead unique materials, specialized resources, and a larger volume of personnel to construct. In addition, permitting can incrementally increase project timelines significantly. As a result, project timelines are usually longer than bare conductor projects, often requiring over a year for scoping and design phases and another year for material delivery, permitting, and deployment. Opportunities are assessed for project acceleration where possible. For example, in 2023, the company finalized a five-year lease on a facility adjacent to the company's local field office in Medford specifically for WMP grid hardening projects to provide additional material storage space in southern Oregon and support timely delivery of projects.

As a part of the on-going program, Pacific Power is currently forecasting to rebuild approximately 625 miles of overhead line over the next five years depending on project pipeline and delivery constraints. In 2024, 125 miles are in design and planned for construction by the end of the year. These specific projects are depicted in Figure 39.

16 Pacific Power successfully completed 65.5 miles of covered conductor through December 1, 2023, and, at the time of plan preparation, is forecasting completion of an additionally 14.5 miles by December 31, 2023.

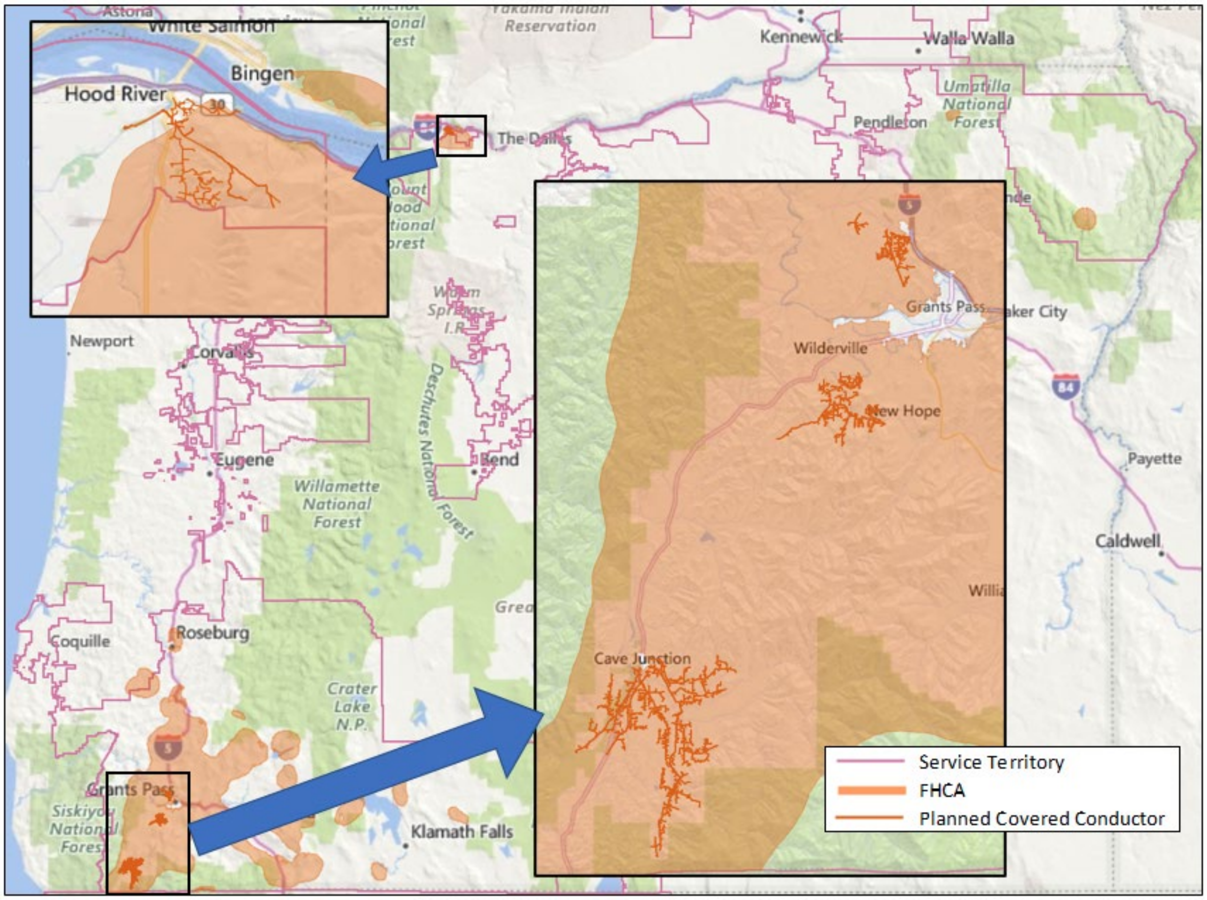

Figure 39: 2024 Planned Construction Projects

The 625 miles currently forecasted in this five-year plan, as shown in Table 21 represent 4.3% of Pacific Power's overhead distribution lines throughout Oregon. To continue evolving the line rebuild program, investment is being made in datasets, software, and tools, described in Section 1, to provide enhanced transparency in project selection and prioritization. While the 2024 construction projects were selected prior to the development of the risk model described in Section 1.2, the tools are expected to have a significant impact on the future project selection and scoping of line rebuild projects.

Table 21: Line Rebuild Program Forecast

Project Component	2023 Actuals	2024	2025	2026	2027	2028	Total[17]
Scoping & Design (miles)	125	125	125	125	125	125	625
Construction (miles)	89	125	125	125	125	125	625

4.2. ADVANCED SYSTEM PROTECTION AND CONTROL

Pacific Power is continuing to replace and upgrade electro-mechanical relays with microprocessor relays throughout the FHCA. Microprocessor relays provide multiple wildfire mitigation benefits. They can exercise programmed functions much faster than an electro-mechanical relay and, most importantly, 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.

Additionally, 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, to be discussed in Section 0. As part of replacing an electro-mechanical relay, the associated circuit breaker or other line equipment may also be replaced, as appropriate to facilitate the functionality of a microprocessor relay.

Starting in 2020, Pacific Power initiated a plan to replace 176 relays and 178 reclosers over a multi-year period, with completion planned in 2026. Pacific Power upgraded a total

17 The current forecast includes rebuilding approximately 625 miles over 5 years (2024-2028). Pacific Power anticipated the line rebuild program will continue beyond 2028. Additionally, where practical Pacific Power will look to accelerate construction activities.

of 90 devices in 2023 as a part of this program and is targeting completion of 80 more in 2024. Figure 40 and Figure 41 below provide visual representations of the existing program scope and overall progress.

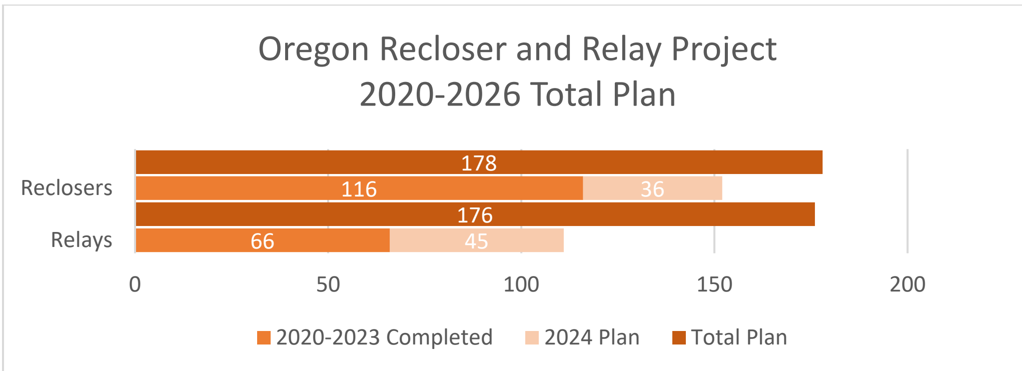

Figure 40: System Automation 2020-2026 Project Progress

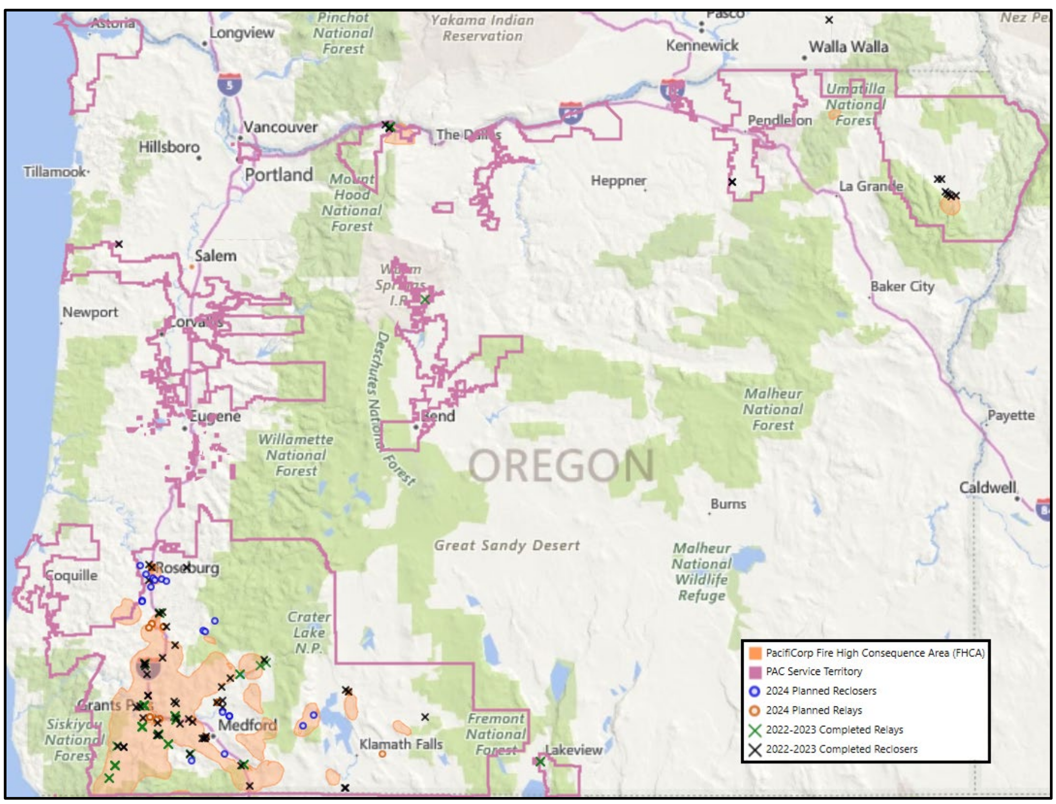

Figure 41: Oregon Completed and Planned Reclosers and Relays Map

4.3. EXPULSION FUSE REPLACEMENT

Overhead expulsion fuses serve as one of the primary system protection devices on the overhead system. A typical expulsion fuse has a small metal element within the fuse body that is designed to melt when excessive current passes through the fuse body, interrupting the flow of electricity to the downstream distribution system. Under certain conditions, the melting action and interruption technique will expel an arc out of the bottom of the fuse tab. To reduce the potential for ignition because of fuse operation, Pacific Power uses alternate equipment that does not expel an arc for installation within the FHCA. Pacific Power's standards for expulsion equipment replacement are based on Cal Fire's Power Line Fire Prevention Field Guide (2021 Edition). Pacific Power plans to proactively replace all expulsion fuses and other linked hardware within the FHCA in a systematic, prioritized manner as part of a multi-year effort. Approximately 26,500 fuse locations were identified for replacement beginning in 2022 with 10,500 fuses replaced in 2023, and completion is anticipated in 2025. Table 22 shows the high-level plan and yearly phasing of the work.

Table 22: Expulsion Fuse Replacement Plan

	2022	2023[18]	2024 Plan	2025 Plan	2026 Plan	2027 Plan	2028 Plan[19]	TOTAL
Fuse Replacements	1,000	10,500	9,000	5,500	TBD	TBD	TBD	26,000

Figure 42 below shows circuits where expulsion fuses were replaced in 2023.

18 The current forecasted totals were made on 12/1/2023 and the actual year end totals might vary.

19 The 2026-2028 TBD values are expected to be updated based on the new risk assessment tools being developed as described in Section 1.

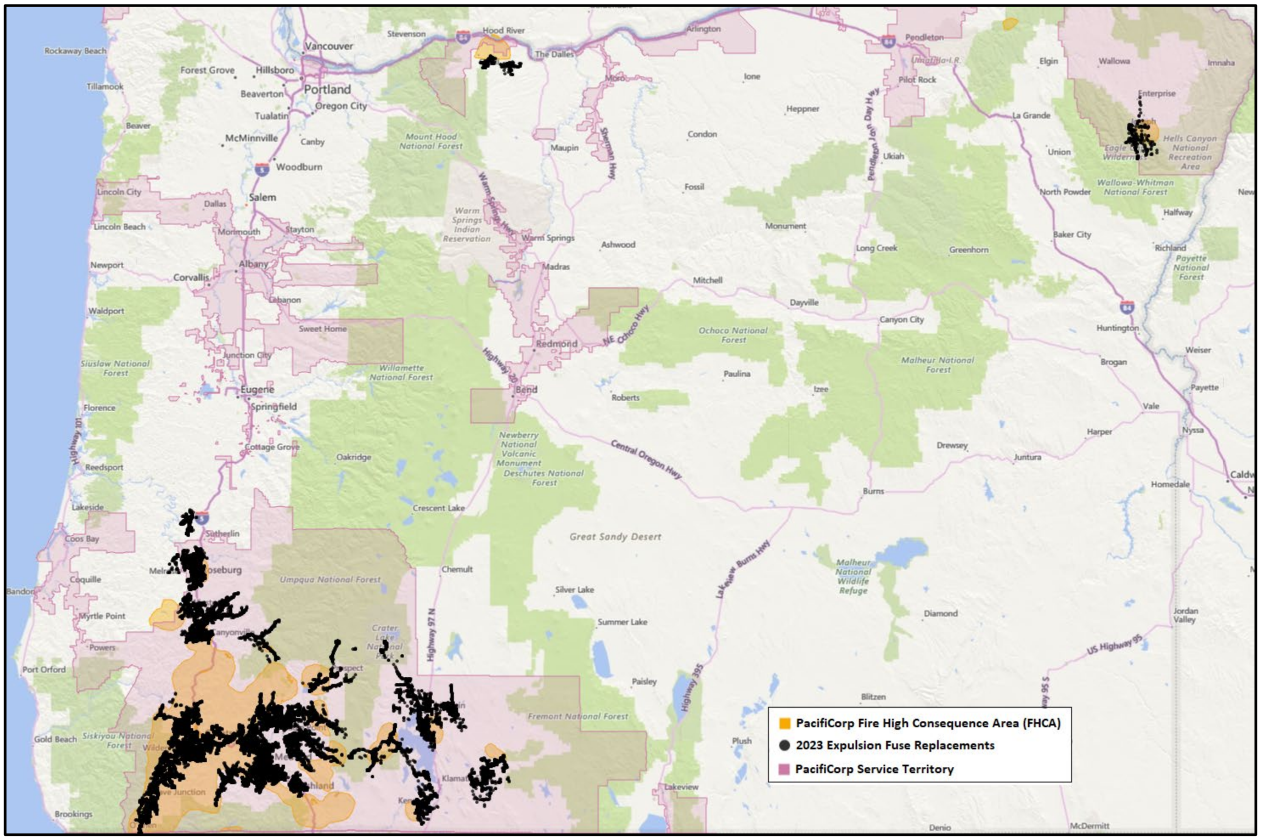

Figure 42: Oregon Expulsion Fuse Replacements in 2023

4.4. FAULT INDICATORS

As described above, Pacific Power is continuing to replace and upgrade electro-mechanical relays with microprocessor relays throughout the FHCA and enable the use of more refined settings for application during periods of greater wildfire risk, discussed in detail in Section 0. To supplement these programs and mitigate the potential impacts to customers of these types of wildfire mitigation strategies to the greatest extent possible, Pacific Power installed 2,156 communicating fault indicators across the Oregon service territory throughout 2022 on circuits interconnected with the FHCA and where EFR settings are most likely to be implemented. No additional fault indicators were installed in 2023 but 300 communicating fault indicators and additional fast trip fault indicators are planned to be installed in 2024. As Pacific Power continues to understand risk and implement mitigation programs such as EFR settings, the company may install additional communicating fault indicators as needed to continue balancing the impact to customers and wildfire mitigation. The fault indicators in-service are on the circuits depicted in Figure 43 below.

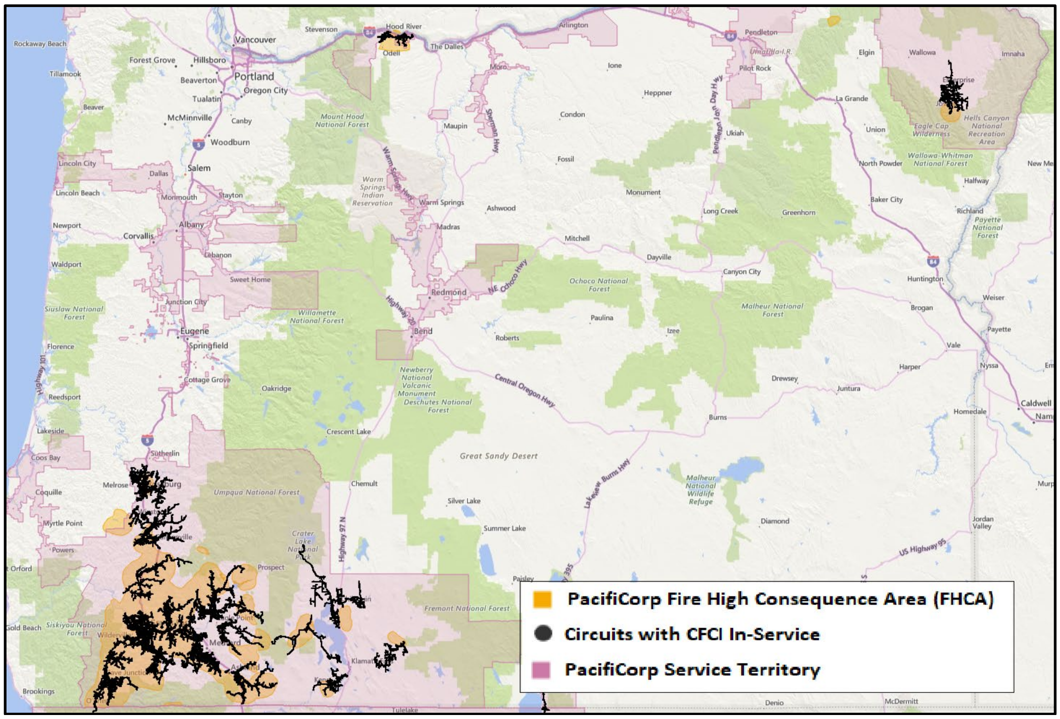

Figure 43: Circuits with Active Communicating Fault Indicators

4.5. EARLY FAULT DETECTION

In 2024 Pacific Power is pursuing the installation of four Early Fault Detection (EFD) devices on a transmission line out of Cave Junction (see Figure 45) that will coincide with devices being installed in California to evaluate new technological capabilities on the system. The circuit was selected due to being in a higher fire threat area as well as being in a remote location that is difficult to access. The EFD devices are continuous monitoring devices that can detect potential failures prior to a failure occurring. The sensors are setup to detect partial discharge events from various radio frequency signals that indicate a potential issue. Detected issues will require Pacific Power to inspect and potentially repair or replace the component where the issue was detected. By placing the devices only a few miles apart it produces faster identification of where the issue happened compared to patrolling a larger area. Depending on the success of the EFD systems additional devices could be added to the system.

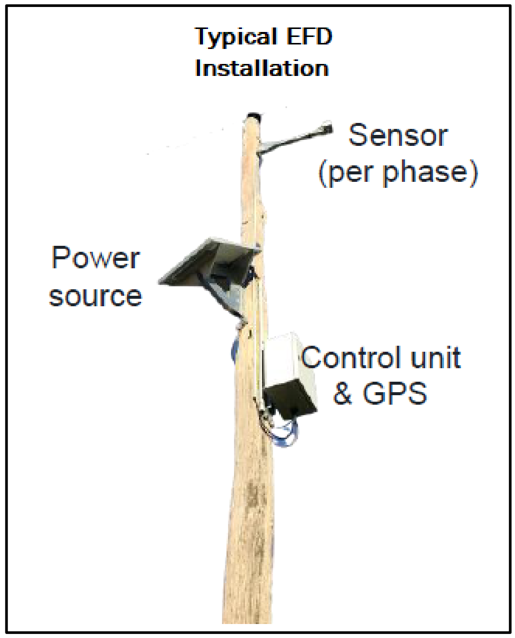

Figure 44: Typical Early Fault Detection Installation

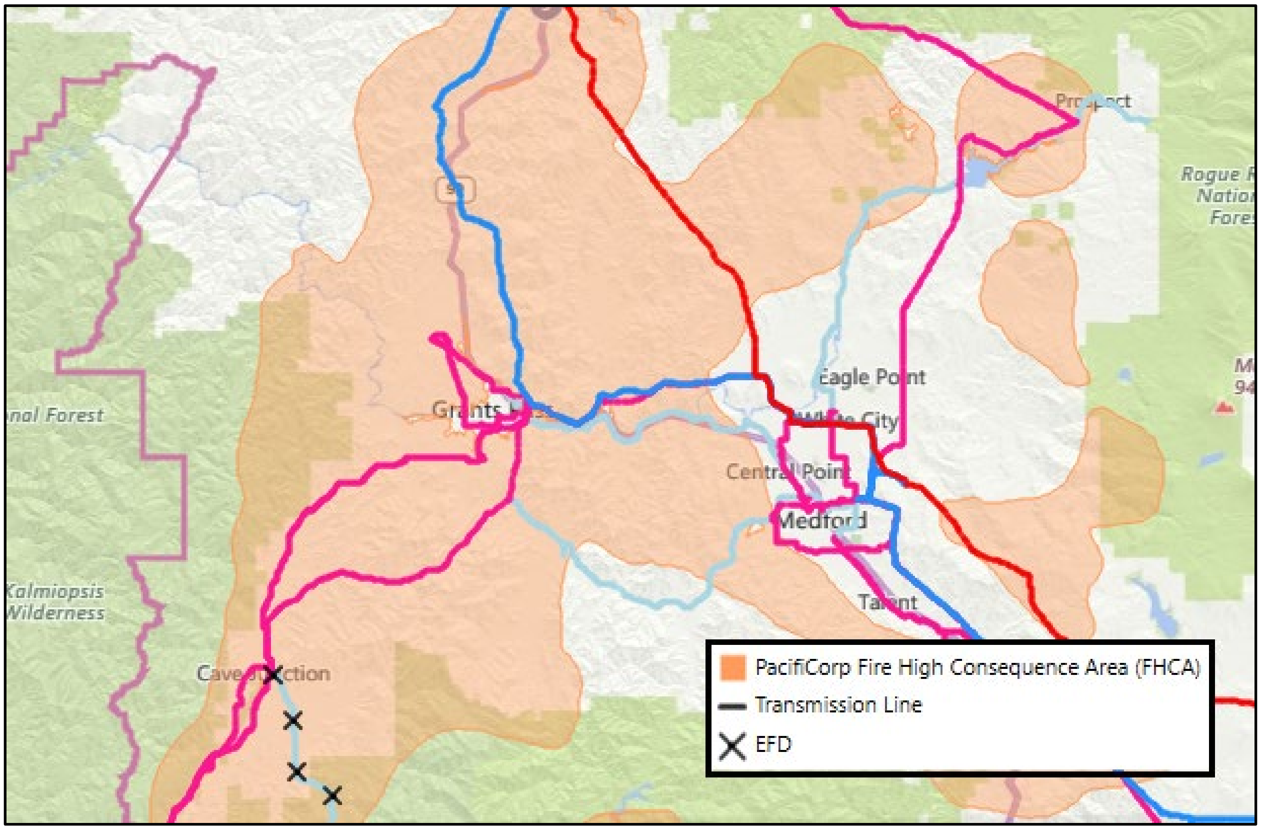

Figure 45: Early Fault Detection Locations

5. SITUATIONAL AWARENESS

As described in Section 1, Pacific Power uses the FHCA, the company's baseline risk map, layered with a risk driver analysis to inform longer term strategic investment and modifications to asset inspections and vegetation maintenance practices. However, as climate and weather patterns change, extreme weather events are predicted to become more frequent, and the potential exists for seasonal, dynamic, and/or isolated risk events to occur that compound or deviate from this baseline risk. Therefore, having an additional sophisticated, dynamic risk model grounded in situational awareness is pertinent to ensure electric utilities know when, where, how, and why to take additional action to mitigate the risk of wildfire in the shorter term.

Pacific Power's approach to situational awareness includes the acquisition of data to forecast, model, and assess the risk of potential or active events to inform operational strategies, response to local conditions, and decision making. These key components, as outlined below and illustrated in Figure 46, rely on a core team of utility meteorologists to guide, execute, and continuously evolve.

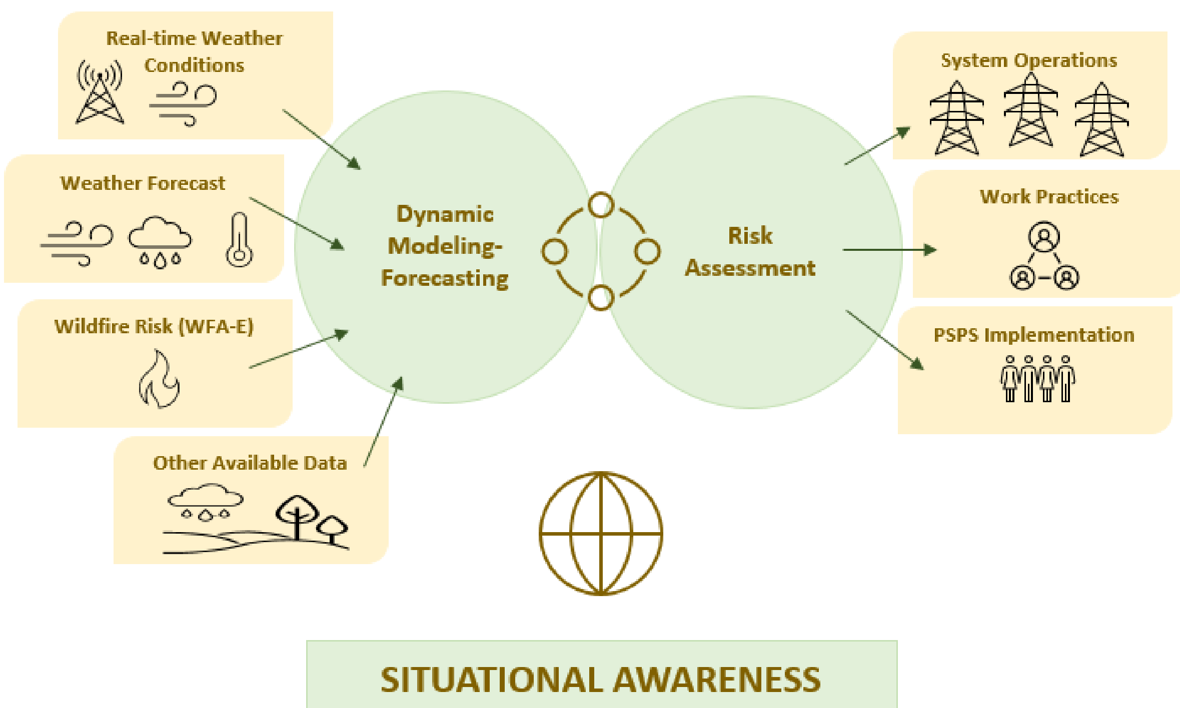

Figure 46: Overview of Situational Awareness

5.1. METEOROLOGY

As described above, the ability to gather, interpret, and translate data into an assessment of utility specific risk and informed decision making is a key component of Pacific Power's situational awareness capability. To support this effort, Pacific Power developed a meteorology department that consists of four full-time meteorologists, one data scientist, and one manager (see Figure 47). The team's experience includes decades of fire weather forecasting for various government agencies such as the National Weather Service (NWS) and Geographic Area Coordination Center (GACC).

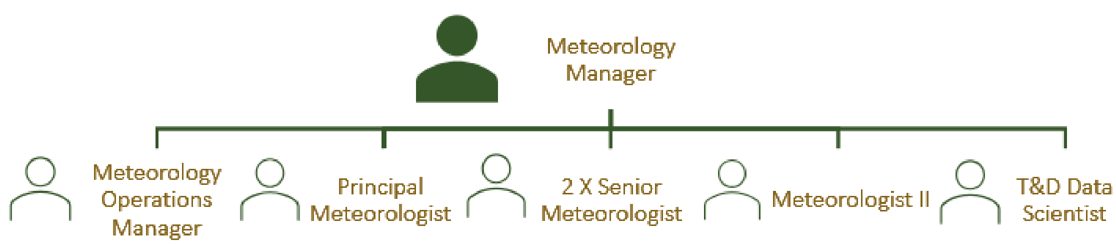

Figure 47: Meteorology Team

The objectives of this department are to supplement the company's longer term risk analysis capabilities by:

- Implementing a real-time risk assessment and forecasting tool,
- Identifying and closing any forecasting data gaps,
- Managing day-to-day threats and risks, and
- Providing information to operations to inform and recommend changes to operational protocols during periods of elevated risk, as depicted below.

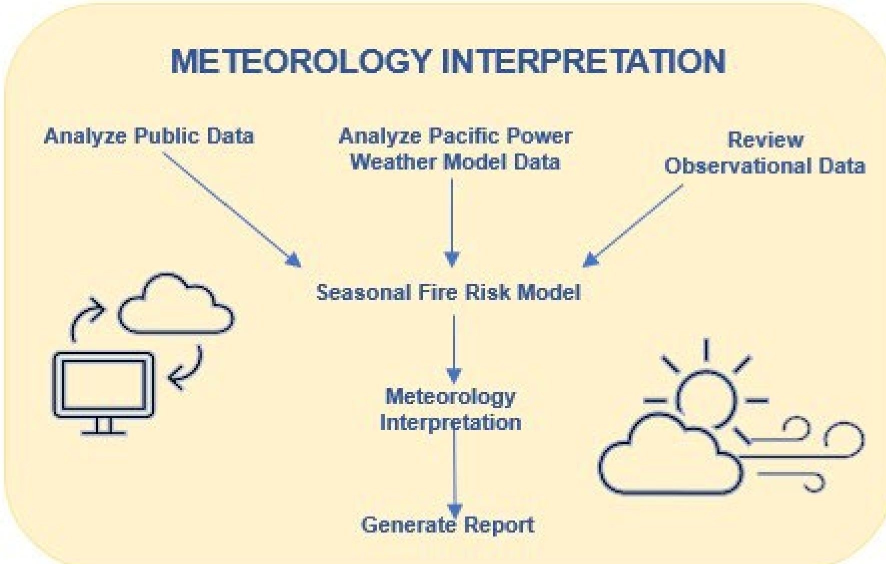

Figure 48: Meteorology Daily Process

Pacific Power's meteorology department also coordinates with government agencies that provide weather warnings. For instance, during high-risk weather events, the company's meteorologists participate as a represented partner in daily coordination calls hosted by the National Weather Service (NWS) and/or the Geographic Area Coordination Center (GACC). In these calls, they ingest information and updates, and may provide additional pertinent information to the GACC. Additionally, the NWS may host briefings during high-risk weather events that are geared toward an emergency management audience. The company's meteorology department also participates in these calls to ensure that forecasting discrepancies are understood and that there is alignment and/or clarity regarding external messages from a utility or the NWS.

5.2. NUMERICAL WEATHER PREDICTION

The creation of an impacts-based forecasting system consisting of an operational Weather Research and Forecasting (WRF) model and a complimentary 30-year WRF reanalysis across the company's entire service territory forms the foundation of Pacific Power's meteorology program. Using the WRF reanalysis and other training data, the company plans to build and train machine learning models to improve its operational thresholds and convert its weather forecasts into a prediction of system impacts. To assess confidence in the calculated values, forecasts are actively monitored to assess trends and potential convergence or divergence between forecasts and actuals during period(s) of elevated risk. As the time of observation nears the forecast period, confidence in the forecasted values increases.

OPERATIONAL WRF MODEL

Pacific Power's meteorology department uses a twice daily, two-kilometer-resolution, hourly weather research and forecasting model. It produces a comprehensive forecast of atmospheric, fire weather, and National Fire Danger Rating System (NFDRS) parameters out to a timescale of 96 hours (four days). The model's high resolution gives a much more complete picture of finer scale atmospheric features than what is available with most public four-day ahead timescale models. In addition, the WRF data is overlayed on overhead distribution circuits and transmission lines, along with other relevant utility asset data, for further analysis.

30-YEAR WRF REANALYSIS

Pacific Power's meteorology department developed a 30-year, two-kilometer resolution, hourly WRF reanalysis. The 30-year WRF reanalysis uses the same configuration and contains the same weather, fire weather, and NFDRS parameters as the company's operational WRF to minimize any potential forecast biases between the two datasets. This reanalysis data was correlated with historic outage data and wildfire events using statistical and machine learning techniques to improve the company's weather-related outage and wildfire risk thresholds. Output from Pacific Power's operational WRF model is then ingested by the company's machine-learning models and GIS tools to convert the daily forecast into potential circuit-level system impacts and to map the intersection of fire weather and outage related risks across its service territory. The 30-year WRF re-analysis provides a daily circuit-level look at the severity of fire weather conditions relative to the past 30 years and, based on that historic data, an assessment of whether the forecast weather event would historically have resulted in an outage on that circuit.

Continual Improvement

The Pacific Power WRF domain covers the entirety of PacifiCorp's six-state service territory. From 2021 to 2022, Pacific Power invested in the procurement of two High Performance Computing Clusters (HPCC) to provide the computational resources needed to run an operational WRF model that large. Currently, the two systems provide a high resolution, four-day forecast of the WRF domain twice daily through a single, deterministic model. The company intends to continue investigating solutions to generate forecasts earlier, improve the accuracy of its forecasts, reduce uncertainty that may exist with reliance on a deterministic model, like the occurrence of low probability, high-impact weather events.

5.3. ONGOING DATA ACQUISITION AND INPUTS

Ongoing data acquisition and inputs, from both internal and external sources, is another key component of Pacific Power's situational awareness model.

WEATHER STATION NETWORK

Public weather data has been available for many years for reference. However, relying only on publicly available data can have limitations. When using publicly available weather data the utility does not have visibility into the maintenance and calibration records or standards used to maintain the weather station collecting the data. Additionally, the frequency of data collection may not match the requisite intervals for performing real time risk assessments and dynamic modeling. Finally, publicly available data may have geographic coverage gaps within the utility's service territory.

When weather stations are owned by the utility, the calibration date and usability of the data is known, the data reporting intervals can be adjusted to report more frequently, and the data can be used to inform real time operations. Additionally, weather stations can be installed and adjusted to pinpoint specific locations needed to inform utility risk assessment. For all these reasons Pacific Power is continuing to invest in a utility-owned and operated weather station network within the company's service territory. Currently, Pacific Power's 158 weather station network in Oregon consists of 148 micro stations and ten portable weather stations. The micro stations are typically installed directly on utility infrastructure and the portable weather stations are available for deployment, as needed, during extreme weather events.

As shown in Figure 49below, data gaps are a key consideration in siting weather stations. These can include a lack of data granularity, as well as the absence of any data altogether. Additionally, as part of its weather station siting methodology, the company accounts for geographic gaps in publicly available weather data from within its service territory, to include factors like data resolution, and consistency.

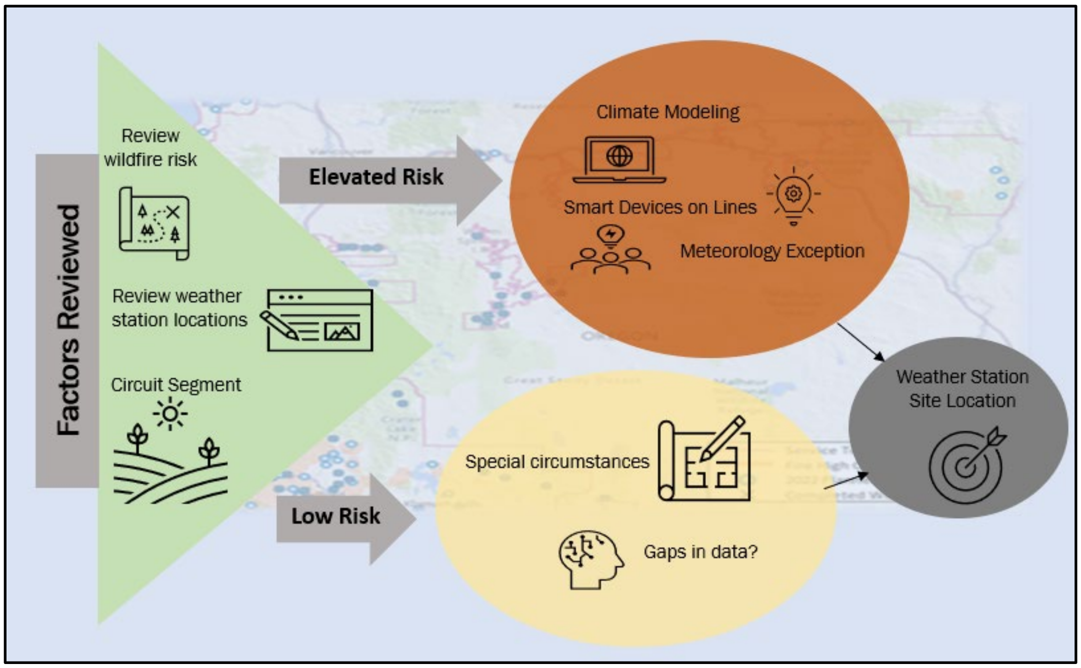

Figure 49: General Weather Station Siting Methodology

Weather station data is used to create a model of routine weather patterns in specific areas. This weather data is then leveraged alongside the operational WRF, its companion 30-year weather data reanalysis, and Technosylva's Wildfire Analyst-Enterprise (WFA-E) software (described in Section 5.4 below), to model potential impacts to infrastructure associated with forecasted weather events and inform operational protocols and decision making, such as when and where to stage resources and how to prioritize restoration times. This improved modeling allows for better anticipation of impactful weather events and is a key component of situational awareness.

Figure 50 and Table 23 below depict the plan and annual phasing of weather stations installation work.

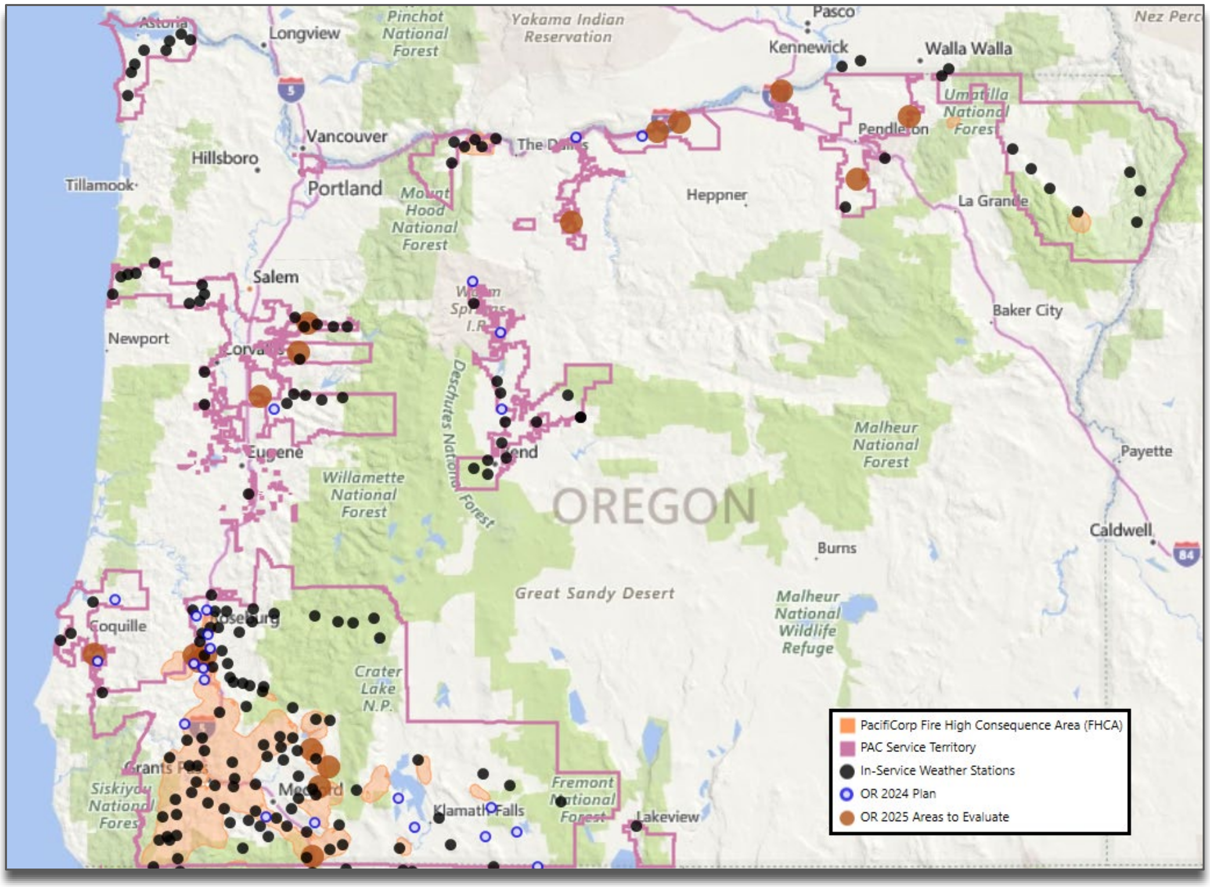

Figure 50: Pacific Power Oregon Weather Station Network (Complete & Planned)

Table 23: Weather Station Build Out Plan

	2023 Actuals	2024 Plan	2025 Areas to Evaluate	Total
New Weather Stations	47	25	17	89
Total OR Fleet	158	183	200	200

In 2024, Pacific Power plans to install 25 additional weather stations, evaluate additional locations for installation in 2025, and depending on data gaps and risk, grow the weather station fleet to approximation 200 stations by 2026. To ensure the weather stations are operating appropriately, the stations will be calibrated on an annual basis.

Pacific Power's meteorology department will continue to evaluate the benefits of additional weather stations.

WILDFIRE DETECTION CAMERAS

Pacific Power has some experience with high-definition cameras in the company's Utah service territory. Additionally, in 2023, Pacific Power acquired access to six stations owned by Portland General Electric with visibility into the company's Oregon service territory to better understand the technology. Building upon this experience, Pacific Power plans to begin installing 5 wildfire detection camera systems, beginning in 2024, as part of a pilot project in its Southern Oregon service territory to supplement existing situational awareness data. The camera systems will be outfitted with 24/7 artificial intelligence software, near infrared, and nighttime detection capabilities and offer both pan-tilt-zoom and 360° continuously rotating capture.

Pacific Power plans to seek input from various state agencies in determining final camera siting locations through its active membership in the Oregon Wildfire Detection Camera Interoperability Committee (OWDCIC).[20] Additionally, Pacific Power will look for existing structures (e.g., on fire lookout towers and existing communication structures) for camera station placement to improve efficiency.

Once installed, the company will work to provide access to fire agencies, dispatch centers, and other public safety partners who may benefit from access to the technology. Additionally, these users will have the ability to receive alerts via email and SMS when camera systems detect smoke to facilitate early detection and quicker response. The

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[20] The OWDCIC was established build relationships, increase wildfire detection camera interoperability and resilience, ensure cross jurisdictional/cross-governmental communications and cooperation. Members include the Governor's Office, public safety agencies, structural fire agencies, Portland General Electric, PacifiCorp, Idaho Power Company, the Public Utility Commission of Oregon, Emergency Managers, the Statewide Interoperability Coordinator, the Oregon Hazards Laboratory at the University of Oregon, the Oregon Department of Forestry, and Tribal Representation.

company anticipates collecting operational data and end user feedback over time to evaluate the program for modifications or expansion. Moving forward, Pacific Power will continue to look for opportunities to partner with state agencies and promote the availability of company facilities available for camera installation.

PUBLICLY AVAILABLE SITUATIONAL AWARENESS DATA

Pacific Power's weather stations and WRF model generate a considerable amount of data each day. The company makes this data available to its employees, customers, and public safety partners through a Situational Awareness website, pacificorpweather.com, alongside weather station observations and forecast data from other trusted government sources, including the National Weather Service. Combining weather station observations with forecast data allows Pacific Power to compare real-time weather observations with forecast data. Further, the wind climatology of each weather station is considered, with real-time and forecast wind conditions color-coded based on station-specific statistics like 95th and 99th percentile values. All the above data are automatically updated on the website as new data is available and can be viewed in maps, tables, and meteograms. Figure 51 below includes sample material from the public situational awareness website.

Figure 51: Sample of Publicly Available Situational Awareness Information from a Weather Station near Bly, OR

This data is also ingested into an internal dashboard used for situational awareness during periods of elevated risk such as during a PSPS. Additionally, this dashboard is also customizable based on the scale of the event and includes station alert speeds and/or other decision points. For example, in September 2022, the wind forecasts indicated that there was potential for wind-related power outages at a time when wildfire danger was high. The data plots on the forecasts also provided the approximate timing of outage-producing winds at multiple weather stations across the service territory, thereby supporting operational decision-making around targeted de-energization(s).

In 2023 and 2024, Pacific Power plans incorporate additional information and improved functionality to the internal dashboard to support situational awareness and improve functionality.

5.4. WILDFIRE RISK MODELS AND TOOLS

Pacific Power leverages a variety of models and tools to assess dynamic wildfire risk, which are described in the subsections below.

FIRECAST AND FIRESIM

As discussed in Section 1.2, in reference to the FireSight tool, Pacific Power procured and implemented Wildfire Analyst Enterprise (WFA-E), the broad suite of wildfire risk modeling tools from Technosylva. WFA-E includes two *seasonal* wildfire models, FireCast and FireSim, and is used by the company to forecast the risk of wildfire and the potential behavior of a wildfire, should it occur. As described in Appendix C – Wildfire Risk Modeling Data Inputs, the inputs for the various WFA-E models are similar. They are, however, used for different purposes. FireCast performs simulations daily to assess wildfire risk more broadly, while FireSim is used to simulate growth and spread of specific and unique fire events.

FireCast: FireCast performs millions of wildfire simulations daily across the company's service territory to provide a 96-hour look ahead that identifies the risk of wildfire (both of ignition and impact) in particular locations. This output is then joined with overhead distribution and transmission asset location data to provide location-specific wildfire risk and consequence forecasts. It is important to note that the asset location data does not assess the probability of a utility asset causing an ignition but, instead, is used to inform operational decision-making, as discussed in Sections 5.5 and 8.

FireCast outputs include the following information:

- An assessment of the potential for a wildfire given fuel, weather, and other conditions.
- A simulation of how a wildfire would behave in the event of an ignition. This would include, for instance, the forecasted rate of spread, size, and flame length.
- Data on the population threatened and potential impact to assets (e.g., identification of buildings that would be threatened in the event of a wildfire).

Figure 52is an example of FireCast output from August 16, 2023. It shows the potential acreage burned should an ignition occur near a circuit. The areas around the circuits highlighted in blue are not forecasted to be impacted by wildfire spread. In contrast, the areas around the circuits highlighted in yellow are forecast to be within 100 acres of wildfire spread. This information is then used to inform operational practices like whether to de-energize proactively or, if time allows, take measures to protect utility assets and communities that could be in the path of a wildfire. This example does not make any assumptions about the effectiveness of the initial or extended attack that may impact the forecast of acres burned.

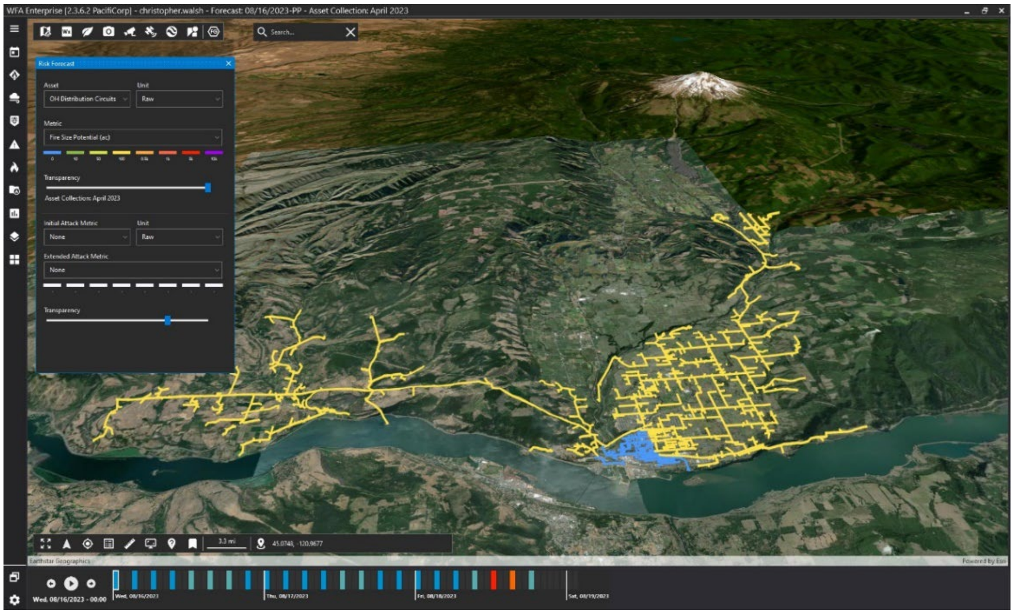


Figure 52: Example of FireCast Output from August 16, 2023

FireSim: FireSim runs simulations that forecast potential fire behavior and spread from a 1 to 96-hour period and assess the potential impact on populations, buildings, utility assets, and other resources in the field. FireSim's model assumes no suppression efforts to slow the fire's spread and considers the following elements:

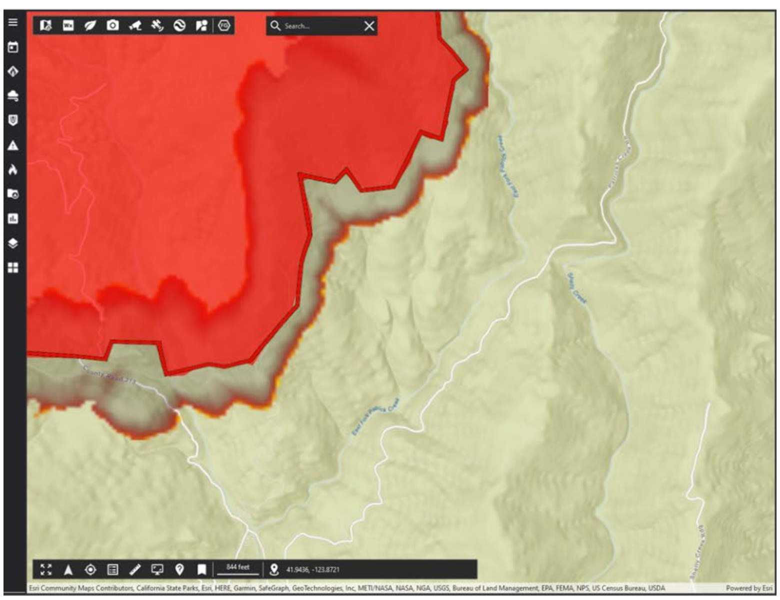
- **Initial Attack Assessment**. Assessment of how difficult initial attack could be for first responders and the probability of stopping the fire within the first operating period. An operational period is "The period of time scheduled for execution of a given set of tactical actions"[21] and varies from incident to incident.
- **Population at Risk**. Projection of the number of people in the path of the fire and the timing of when the fire is likely to arrive.

21 Federal Emergency Management Agency. FEMA Operational Planning Manual FEMA P-1017. June 2014. Sourced November 6, 2023.

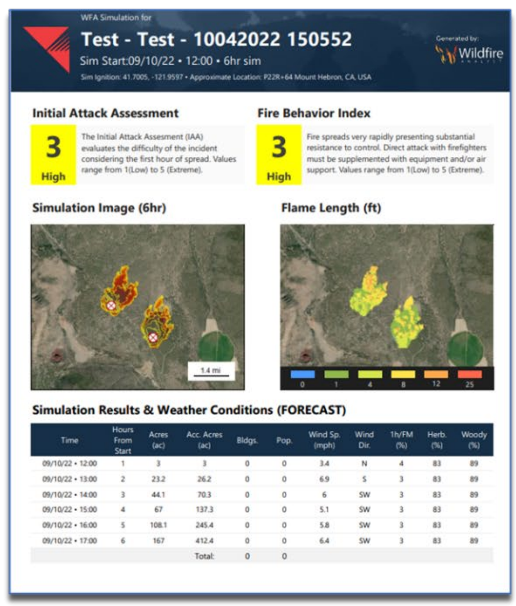
- **Assets at Risk**. Physical assets like utility equipment, residential and commercial structures, barns, outbuildings, other structures, and the timing of when the fire is likely to arrive.
- **Places at Risk**. These are locations identified on the maps that may not be physical assets but have other significance. These could include parks, reservoirs, cultural sites, campgrounds, or other locations.
- **Weather and fuels conditions**: Wind speed, direction, fuel moisture content.

The figure below includes an example of both FireSim outputs and reports. While the event did not occur in Oregon, the example output is from a real-world event, namely the Smith River Complex Fire, which occurred in northern California in 2023. The area shaded red on the left side of the figure represents the current fire area, meaning the known perimeter of the fire at the time that simulation in Figure 53 was run. The red line ahead of the fire area is a forecast of the estimated growth and forecasted spread of the fire.

FireSim Output from the Smith River Complex Fires (August 18, 2023)



Example of FireSim Report



WFA Simulation for

Test - Test - 10042022 150552

Sim Start:09/10/22 • 12:00 • 6hr sim

Sim Ignition: 41.7005, -121.9597 • Approximate Location: P22R+64 Mount Hebron, CA, USA

Generated by: Wildfire

Initial Attack Assessment

3 High

The Initial Attack Assesment (IAA) evaluates the difficulty of the incident considering the first hour of spread. Values range from 1(Low) to 5 (Extreme).

Fire Behavior Index

3 High

Fire spreads very rapidly presenting substantial resistance to control. Direct attack with firefighters must be supplemented with equipment and/or air support. Values range from 1(Low) to 5 (Extreme).

Simulation Image (6hr)

Flame Length (ft)

Simulation Results & Weather Conditions (FORECAST)

Time	Hours From Start	Acres (ac)	Acc. Acres (ac)	Bldgs.	Pop.	Wind Sp. (mph)	Wind Dir.	1h/FM (%)	Herb. (%)	Woody (%)
09/10/22 • 12:00	1	3	3	0	0	3.4	N	4	83	89
09/10/22 • 13:00	2	23.2	26.2	0	0	6.9	S	3	83	89
09/10/22 • 14:00	3	44.1	70.3	0	0	6	SW	3	83	89
09/10/22 • 15:00	4	67	137.3	0	0	5.1	SW	3	83	89
09/10/22 • 16:00	5	108.1	245.4	0	0	5.8	SW	3	83	89
09/10/22 • 17:00	6	167	412.4	0	0	6.4	SW	3	83	89
			Total:	0	0					

Figure 53: Example FireSim Output (left) and Report (right)

In this example FireSim report above, the rating of the Initial Attack Index difficulty and Fire Behavior Index are highly influenced by fuels models and forecasted weather conditions. The image on the left shows the forecasted direction of the fire and the image on the right shows the forecasted flame length. Below the images is a table showing a time-based impact analysis of forecasted acres burned, population and buildings at risk and weather and fuel conditions. In sum, FireSim modeling is used to assess potential fire growth, spread, and damage to inform response efforts and decision-making by Pacific Power operations.

FIRE POTENTIAL INDEX

Prior to the start of the 2023 fire season, Technosylva developed a complementary metric called the Fire Potential Index (FPI) for Pacific Power. The FPI is a supplementary metric that quantifies the potential for large or consequential wildfires based on weather, fuels, and terrain. In combination with the Modified Hot Dry Windy Index (mHDWI), the FPI is used to guide operational decision-making as it relates to wildfire risk and spread.

The following three inputs contribute to the final FPI score:

- **A Fuel Model Complex** that assesses the type of fuels and the time elapsed since the last fire to quantify how the fuels may affect fire behavior, type, and suppression difficulty. The model considers fire history, fuel growth, and fuel dryness over time in response to weather conditions to support accurate wildfire modeling.
- **Weather Conditions** that consist of a combination of wind gusts, temperatures, and fuel conditions. For wind driven risk events in particular, Pacific Power has identified some geographically driven patterns that correlate to higher risk.
- **Terrain Difficulty Index** which represents the level of geographical complexity to access an area. For instance, regarding fuels and terrain driven risk events, large areas of contiguous complex fuel and terrain in areas of limited or difficult access present the greatest risk when fuels are dry, and weather is hot and dry.

The scores from these inputs are then correlated to a level of fire risk in Figure 54 below shows the FPI scoring scale and percentiles. An FPI value or FPI percentile can be used to determine the FPI risk level. For instance, FPI values >37.5 or percentiles >99% indicate that fire risk is extremely high. In contrast, an FPI value <5 or percentile <60 indicate that fire risk is low.

FPI Category	FPI Values		FPI Percentiles
Very Low	<5	OR	<60
Low	5-10		60-80
Moderate	10-13.5		80-85
High	13.5-23		85-95
Very High	23-37.5		95-99
Extreme	> 37.5		>99

Figure 54: Fire Potential Index Scale

MODIFIED HOT DRY WINDY INDEX

In 2023, Pacific Power analyzed over 2,000 wildfires between 1991-2021 across the western United States that were known to be or widely suspected of being caused by power lines.[22] Based on its analysis of the ignitions, which included fire size and consequence, the company identified a correlation between utility ignition and a measure of fire weather based on temperature, relative humidity, wind, and fuels conditions. As a result, Pacific Power created an index called Modified Hot Dry Windy Index (mHDWI). The mHDWI combines the Energy Release Component (ERC) from fuels with weather data from the surface and low levels of the atmosphere from the Hot Dry Windy Index (HDWI)[23] to help determine what days are more likely to have conditions that could result in consequential wildfires. Based on this analysis, levels of risk (non-fire season, low, elevated, significant, and extreme) were assigned to certain combinations of

22 States included in the analysis were Utah, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Washington, and Wyoming.

23 United States Forest Service. "A Brief Introduction to the Hot Dry Windy Index."

environmental conditions that can be used to inform decision-making. Figure 55 visually depicts the historic analysis, correlation of utility ignitions to the mHDWI and wind gust percentiles and assigned levels of risk expressed using a five color-code scheme where a higher percentile of wind gusts and mHDWI correlated to a higher level of risk. In terms of the historic analysis, circles in blue reflect fire events where no structure damage or injuries occurred. The circles in red reflect events where one or more structure was damaged, or one or more injury occurred. As depicted in the figure, the events in red, where structure damage or injuries occurred, correspond to significant or extreme risk levels.

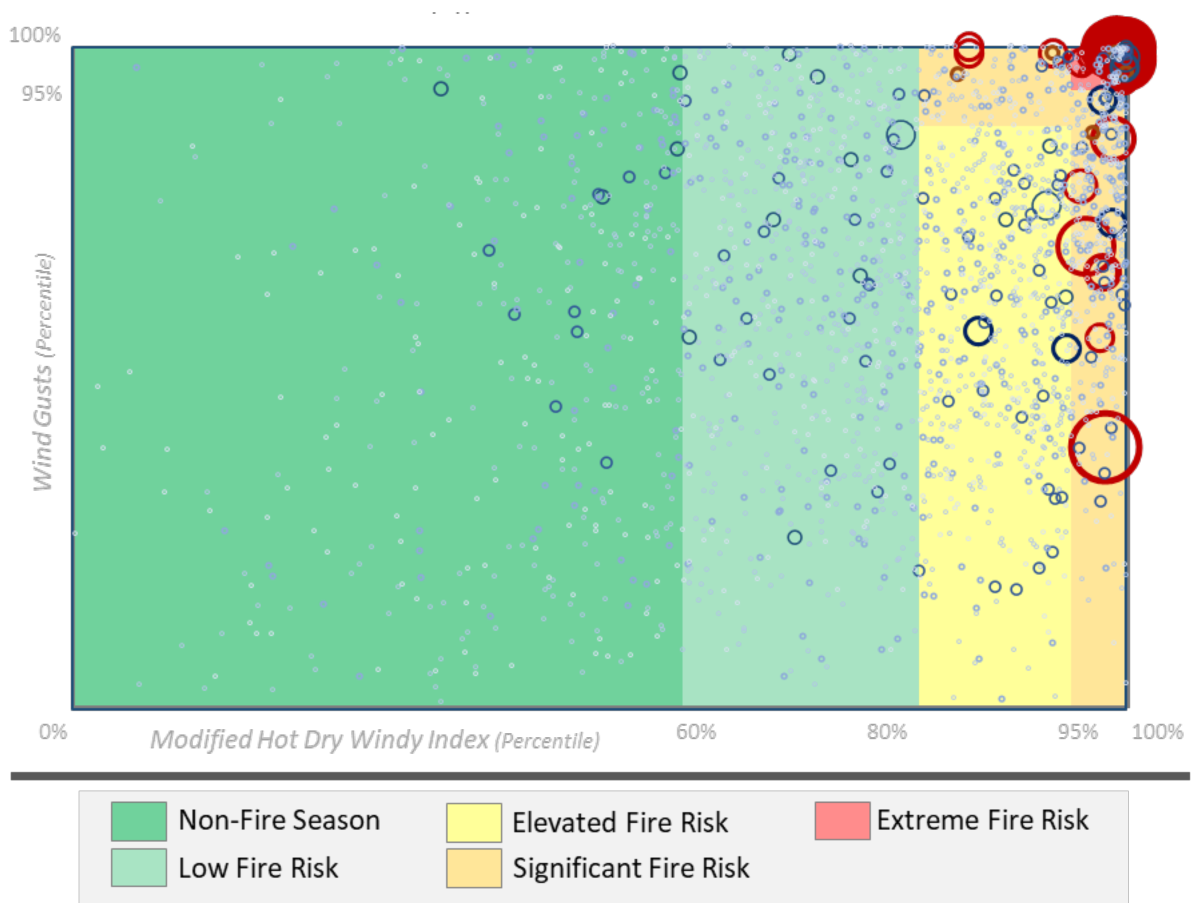


Figure 55: Correlation of Utility Ignitions to mHDWI and Wind Gust Percentiles to Determine Risk Levels

5.5. APPLICATION AND USE

Pacific Power's meteorology team leverages the various analysis, model outputs, and indices described above to produce a district-based, weather-related system impact forecast. Assessing District Fire Risk

Meteorology combines the Fire Potential Index (FPI), the mHDWI, and (where applicable) an analysis of the state of grass curing to produce a daily district-based, weather-related system impacts forecast that guides operational decision-making. Additionally, when moving into an elevated, significant, or extreme wildfire risk, meteorology also performs an additional review of fuels and fire weather forecasts and observations by using some or all the metrics and methods identified in Table 24 below.

Table 24: Additional Considerations for District Fire Risk

Additional Considerations when Considering District Fire Risk	
Current or Recent Wildfire Activity	Current or recent wildfire activity is an indication that the weather and fuels conditions will contribute to fire occurrence and spread.
Geographic Area Coordination Center (GACC) Products	Seven-Day Significant Wildfire Potential, Fuels & Fire Behavior Advisories, and other outlooks or discussion products.
National Weather Service Watches or Warnings	Fire Weather Watches, Red Flag Warnings, High Wind Warnings, and other products issued by the National Weather Service
Evaporative Demand Drought Index (EDDI)	EDDI identifies anomalous atmospheric evaporative demand and provides an early warning of increased wildfire risk.
Fire High Consequence Areas (FHCA) (Y/N)	Fire High Consequence Areas are pre-identified areas of elevated risk based on historical fires, climatology, geography, and populations
Fire Potential Index (FPI)	FPI quantifies the potential for large or consequential wildfires based on weather, fuels, and terrain.
Fuels Conditions (Grasses, Live Fuels, & Dead Fuels)	Observations of the local fuel conditions including 1, 10, 100, and 1000-hour dead fuel moisture, herbaceous and woody live fuel moisture, tree mortality, Energy Release Component, etc.
High Resolution Fire Weather Forecasts (WRF)	Pacific Power's two-kilometer WRF model produces a twice daily territory-wide forecast of fire weather and National Fire Danger Rating System (NFDRS) outputs across a 96-hour time horizon.
Severe Fire Danger Index	Publicly available index that uses two United States National Fire Danger Rating System indices that are related to fire intensity and spread potential.
Vapor Pressure Deficit (VPD) one month running average	Vapor Pressure Deficit is a measure of the atmospheric demand (thirst) for water. Values above the 94^{th} percentile have been associated with large wildfires.
Wildfire Consequence Modeling (WFA-E)	Millions of wildfire simulations are performed daily to map out potential wildfire risk and consequence across the service territory.

If the forecast indicates that a significant fire weather event is possible within the forecast period, the meteorology team may leverage more resources to analyze concerns such as timing, strength, areas potentially impacted, and forecast confidence. These resources include tools like wildfire consequence modeling and high-resolution models to identify localized areas of greatest risk. Additionally, the meteorology team may collaborate with the local National Weather Service office and/or the regional GACC office if there is significant or extreme wildfire risk.

Significant fire potential forecasts issued by the Geographic Area Coordination Center (GACC) are also used as supplemental criteria to the mHDWI, an output of PacifiCorp's WRF model. In addition to the GACC forecast, the meteorology team closely monitors fuel and Energy Release Component (ERC) charts that are published by regional GACC coordination centers. Wildfire and traffic cameras are also used to assess fuel conditions. Additionally, the on-duty meteorologist also reviews the most recent publicly available weather forecast model trends and National Weather Service products (forecast discussions, watches, warnings, advisories, etc.) to complete a more comprehensive analysis.

The risk level for each district is then determined by the on-duty meteorologist's evaluation of all the information gathered relative to the criteria listed in Figure 54. In addition to the system impact forecast matrix shown below, a written weather summary is prepared in which the on-duty meteorologist provides key forecast takeaways and additional detail regarding the strength and timing of any weather threats.

This analysis is then combined with the team's district-based fire risk forecast to produce a complementary system impacts forecast that is used to support decision-making related to implementation of the operational, short term risk mitigation programs and measures that will be discussed in Section 6, Section 7, and Section 8. An example of a district-based fire risk forecast is shown in Figure 56 below.

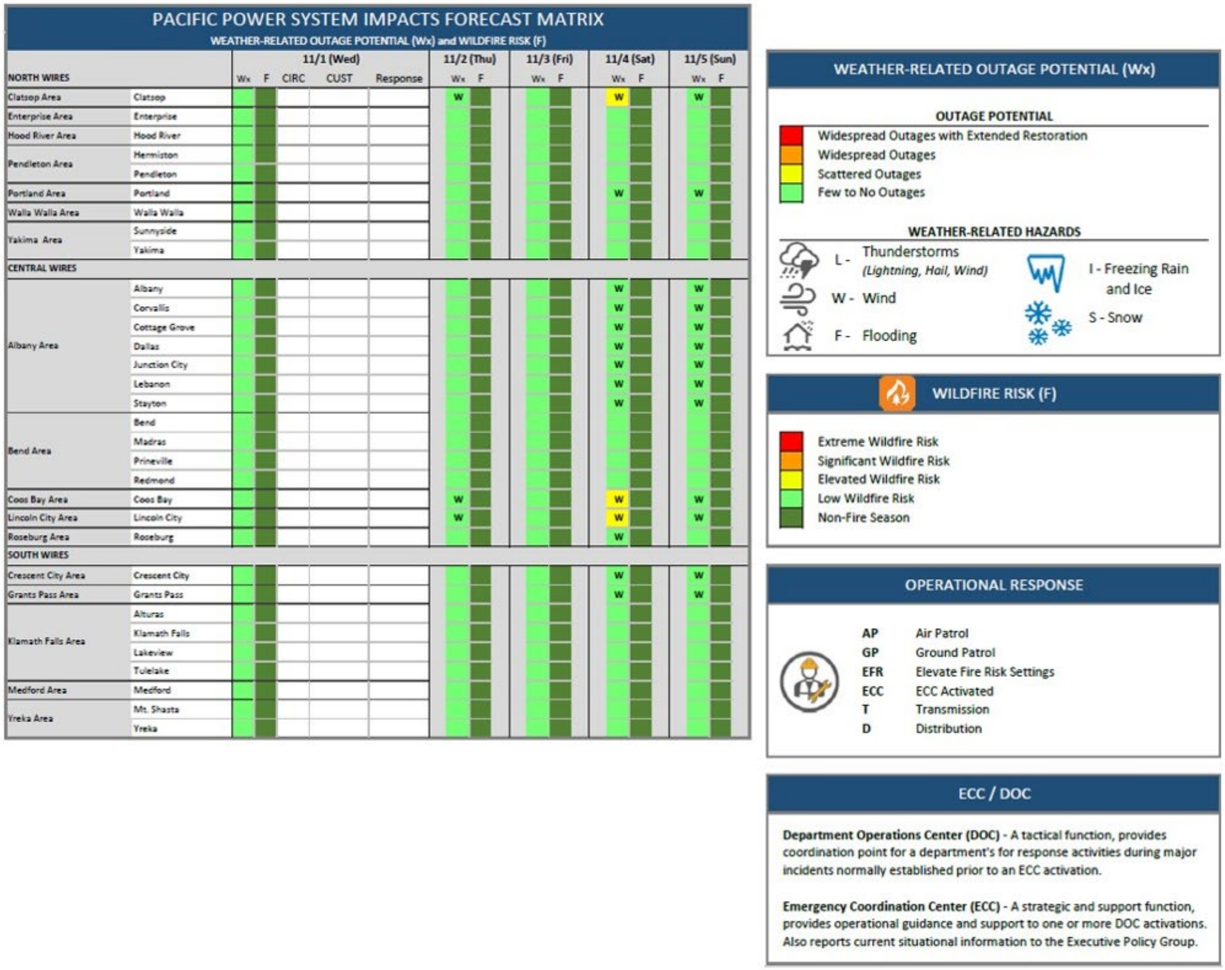


Figure 56: Example System Impacts Forecast

In sum, Pacific Power's meteorology team leverages a considerable number of resources to produce its forecast reports. These include internal and external data sources and metrics, like the company's Weather Research Forecast (WRF) model, Modified Hot Dry Windy Index (mHDWI), Fire Potential Index (FPI), Geographic Area Coordination Center (GACC) forecast reports, and publicly available weather trends.

The company recognizes that under certain conditions, wildfires can occur anywhere there is sufficient wildland vegetation that is dry and flammable, even in historically low-risk areas; therefore, the system impacts forecast covers the company's entire service territory. Typically, the forecast reports are produced on normal business days, and references to "daily" refer to normal business days. During periods of extreme weather or wildfire risk, however, a forecast may be generated every day, including weekends and holidays.

SEASONAL FORECAST

To supplement the system impacts forecast, Pacific Power is planning to provide public safety partners with a 2023 district level seasonal summary that incorporates any known areas of change for 2024. This information will be provided to public safety partners to highlight climatology of interest in specific areas based on 2023 experience and known areas of change in 2024. Public safety partners can use this information for additional situational awareness. To avoid mixed messaging, this information is intended for Public Safety partners only.

6. SYSTEM OPERATIONS

Adjustments to power system operations can help mitigate wildfire risk. System operations adjustments may include the modification of relay settings for protective devices on distribution lines or changes to line re-energization testing protocols described further in this section. These adjustments are not universally applied to power system operations because there are certain disadvantages in their use, especially because they may increase outage frequency and duration experienced by customers. In other words, a balance is required to provide customers with reliable power while still mitigating wildfire risk. To help balance these concerns, Pacific Power is deploying technologies such as fault indicators and assessing outages to inform short term mitigation projects which are also discussed in the subsections below.

6.1. ELEVATED FIRE RISK SETTINGS

Line protective devices, such as line reclosers, are currently deployed on various transmission and distribution lines throughout Pacific Power's service territory. When a line trips open due to fault activity, reclosers can be programmed to momentarily open, allow the fault to dissipate, then reclose to assess whether the fault is temporary. The reclosing function gives the ability to restore service on a line that has tripped while maintaining the option to open again if the fault persists. If the fault is permanent, the recloser will operate and stay open (known as the "lock out" state) until the line has been deemed ready for re-energization. Figure 57 below generally depicts one potential configuration of a distribution circuit with multiple line reclosers installed.

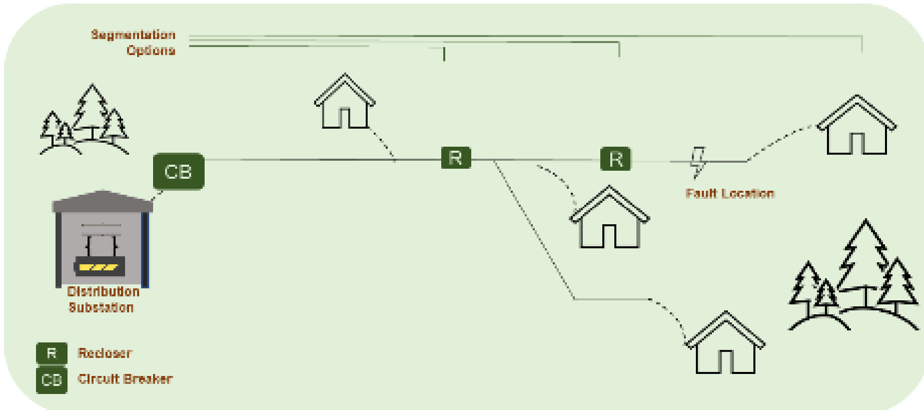


Figure 57: Example of Distribution Circuit with Multiple Reclosers

In general, recloser operation is beneficial because it reduces the number of sustained outages and improves customer reliability. The reclosing function, however, implicates some degree of ignition risk because additional energy can be released if a fault persists. When a fault is detected on the line, a recloser will trip and reclose to re-energize the line based on predetermined settings. If the fault is temporary in nature and is no longer present upon the reclose operation, the line will re-energize resulting in limited impact to customers. If the fault persists, however, reclosing can, depending on the circumstances, potentially result in arcing or an emission of sparks. Accordingly, a strategic balance between customer reliability and wildfire mitigation goals is required.

Pacific Power is implementing additional strategies on the distribution network, including the use of modified and more sensitive protection and control schemes, referred to as Elevated Fire Risk (EFR) settings. Such applications on the distribution network, however, can have a greater impact on customer reliability and Pacific Power is exploring different strategic combinations to find the right balance.

For example, the company does not typically disable reclosing seasonally. Instead, the daily risk assessment process and situational awareness reports described in Section 5.5 are leveraged and a risk-based approach to the implementation of EFR settings is used. For example, when meteorological conditions of increased wildfire risk occur, an alternative operating mode may sometimes be used to increase protection element sensitivity, clear detected faults faster, reduce the number of reclose attempts, increase the open interval time between trip and reclose operations, or set the recloser to lock out upon a single trip event. Pacific Power plans to continue evaluating situational awareness, customer outages and other information to further optimize the settings and implement EFR settings as needed.

6.2. RE-ENERGIZATION PRACTICES

In addition to enabling EFR settings as described above, Pacific Power also implements risk-based changes to re-energization practices, which can include patrols and line testing. Line testing can be an efficient tool to maintain customer reliability, like the use of reclosing, as described in the previous section. At the same time, line testing can potentially result in arcing or an emission of sparks if a fault has not yet cleared when the line is evaluated. To mitigate this risk (depending on local circumstances), an enhanced patrol that includes a patrol and step restoration of the entire circuit prior to line testing, may be required under certain conditions. This often results in an increase to restoration time and costs.

6.3. FAULT INDICATORS TO MITIGATE IMPACTS

The time it takes to patrol a line and the impact to customers can be significantly reduced when a fault location can be determined. Therefore, as described in Section 4.4 and depicted in Figure 58, the utility has installed fault indicators across its Oregon service territory on circuits where EFR settings are more likely to be implemented, such as the FHCA and surrounding areas. When an outage occurs, regional operators and field personnel use these tools to narrow down potential fault locations, optimize the deployment of resources, and expedite restoration.

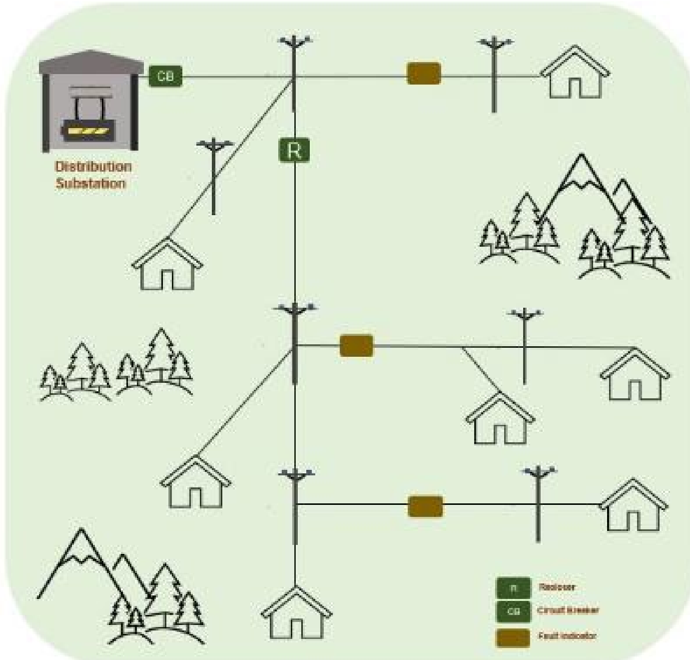


Figure 58: General Fault Indicator Configuration

EFR settings will continue to be implemented to reduce the wildfire risk associated with prolonged fault events while being strategic in the EFR implementation to balance the reliability impacts to customers. Pacific Power will also continue to assess the need for and install additional fault indictors as described in Section 4.4.

6.4. 2023 EXPERIENCE

In 2023, Pacific Power implemented its EFR program across the company's service territory based on dynamic risk assessment forecasts and tracked outages with EFR settings enabled. EFR settings, as discussed above, leverage a faster isolation scheme to reduce the amount of energy that may be released during an event, which can lead to more frequent outages. Each outage that correlates to a device having EFR settings enabled is considered an event where risk was mitigated through the refined settings as the settings limit the amount of energy that may be released. The correlation between EFR settings being enabled and an outage being recorded does not mean the settings caused an outage. Outages can be caused by a variety of factors, not limited to, planned work and/or environmental factors. Figure 59 below depicts the number of outages with and without EFR enabled each month in 2023 compared to a five-year average.

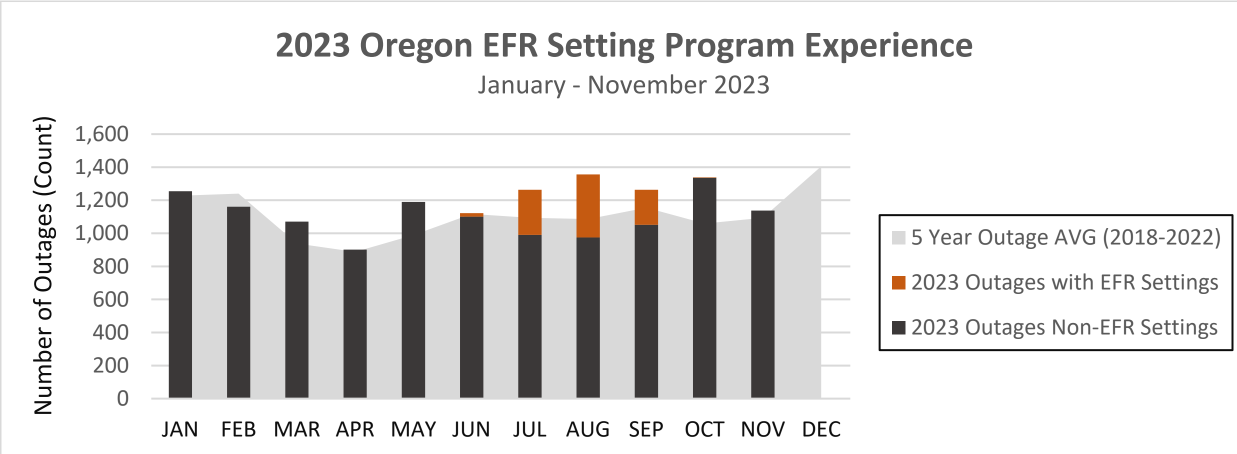


Figure 59: 2023 EFR Setting Impact

As shown above, Pacific Power experienced approximately 890 EFR outages between June and September in 2023 during periods of elevated fire risk. This represents approximately 7% of the total outages experienced in 2023 and 18% of outages experienced from June to September 2023. The EFR outages were reviewed in conjunction with seasonal risk experienced in 2023 to identify and prioritize short term mitigation projects for completion prior to the 2024 fire season to reduce wildfire risk and mitigate potential reliability impacts to customers associated with the EFR program. Examples of prioritized projects include upgrading cutouts, fuses, crossarms, and insulators on circuits that experienced EFR outages in 2023.

Additionally in 2023, Pacific Power implemented alternate re-energization practices that required incremental or augmented patrols after system faults, which led to increased restoration times. While these strategies mitigate wildfire risk, Pacific Power recognizes the disruption on customers and communities when there are additional and longer duration outages. For example, in 2023, patrolling prior to restoration of EFR outages resulted in an incremental cost increase of about 55% compared to traditional outage response efforts.

7. FIELD OPERATIONS AND WORK PRACTICES

During fire season, Pacific Power modifies field operations and work practices to further mitigate wildfire risk. Additionally, investments are made in tools and equipment to mitigate wildfire risk.

7.1. MODIFIED PRACTICES AND WORK RESTRICTIONS

As a part of the situational awareness reports and briefings prepared by the meteorology department, the operations department within Pacific Power considers the local weather and geographic conditions that may create an elevated risk of wildfire. The intent behind implementation of this practice is to reduce the potential of direct or indirect causes of ignition during planned work activities, fault response, and outage restoration.

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 Pacific Power personnel are working in the field (collectively "field personnel"), such field personnel are equipped with basic tools to extinguish small fires.

Figure 60: Line Workers Performing Work

Some wildfire risk can be mitigated 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 the weather forecasts provided to them as part of the situational awareness program, as discussed in Section 5 of this document.

During fire season, operations managers are encouraged to defer any nonessential work at locations with dense and dry wildland vegetation, especially during periods of heightened fire weather conditions. If essential work needs to be performed in the FHCA and other areas with appreciable wildfire risk, certain restrictions may apply, including:

Hot Work Restrictions. Evaluating whether field personnel should perform work during a planned interruption, rather than while a line is energized.

Time of Day Restrictions. Considering using alternate work hours to accommodate evening and night work when there may be less risk of ignition.

Wind Restrictions. Deferring work, if feasible, when there are windy conditions at a particular work site.

Driving Restrictions. Keeping vehicles on designated roads whenever operationally feasible.

Worksite Preparation. Removing wildland vegetation that poses an ignition risk from a worksite if the work to be performed involves the potential emission of sparks from electrical equipment, and only where it is allowed in accordance with land management/agency permit requirements. In addition to clearing work, water truck resources, discussed below, are strategically assigned to accompany field personnel working in wildland areas during fire season, especially in the FHCA. Depending on local conditions, dry vegetation in the immediate vicinity may be sprayed with water before conducting work as a preventative measure.

As noted above, whether to implement these restrictions is evaluated based on the daily reports and briefings provided by meteorology. As Pacific Power is continuously improving and evolving its plan and programs, the process below is subject to change and is managed by internal company policies and procedures.

In general, whenever wildfire risk potential is minimal to none, work may be conducted using normal operating practices. However, when meteorology forecasts wildfire risk conditions that are elevated, significant, or extreme, local operations may modify operating practices. For example, the personal protective equipment and basic firefighting tools described above are required for any field work conducted during periods of elevated fire risk. Local area management will also evaluate, after considering multiple factors regarding the local circumstances of a particular circuit, whether any hot work modifications should be made. If wildfire risk is significant or extreme, local area management will also consider whether any additional work is appropriate. Section 5 of this document provides an in-depth discussion of how meteorology forecasts impact field operations and work practices.

ADDITIONAL LABOR RESOURCES

To implement some of the wildfire mitigation programs described above and at greater length in Section 6 of this document, incremental labor resources and field personnel time is often required to: (1) support system operations in assessing localized risk and administering EFR settings and (2) respond to outages during fire season with additional patrols and coordination.

Under normal operating procedures, system operators and field personnel work together daily to manage the electrical network and there are many situations where system operators depend on field personnel to gather information and assess local conditions. As discussed in Section 0, there are system operations procedures during wildfire season for implementing EFR settings and limiting line-testing. Consequently, system operators need field personnel to gather information and assess local conditions during fire season more often than what is 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.

Depending on current conditions at the work site and the duration of the restoration work, field personnel may also spend incremental time when responding to an outage during fire season. As discussed in Section 6.2, Re-Energization Practices, a heightened risk exists with traditional restoration practices. To mitigate this risk, field operations may perform line patrol on certain de-energized sections of circuits, most notably during fire season and particularly in the FHCA. 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 a particular facility; instead, it is a quick visual assessment specifically targeted to identify damaged equipment or obvious foreign objects that may have fallen into the line during restoration work.

ACTIVE WILDFIRE RESPONSE

Pacific Power monitors and may support the response of active wildfires in or near assets and service territory. While Pacific Power employees may carry small fire suppression equipment, they are not professionally trained fire fighters; therefore, when they encounter a fire of any appreciable magnitude, Pacific Power employees will call 9-1-1. For known active wildfires, Pacific Power will monitor the situation and may contact the appropriate incident management team to support efforts needed which can include de-energization of lines.

EQUIPMENT AND TOOL PURCHASES

In addition to changes in work practices, Pacific Power invests in tools and equipment to mitigate wildfire risk. These investments include (1) mobile communication devices, (2) vehicles, (3) personal suppression equipment, and (4) water trailers.

Mobile Communication Devices

Pacific Power operates and serves customers in very rural locations, some of which have limited to no cellular connectivity back to the local district office and/or the control center. During large disasters, like wildfire events, Pacific Power field personnel need to be able to communicate quickly and effectively to maintain safe operation of its system and support emergency response and restoration activities. Therefore, in 2022 Pacific Power procured a compact rapid deployable cell tower, this device is also known as cell on wheels (COW). This equipment, as shown on the right, generates an area of FirstNet cellular and

Wi-Fi coverage, to improve communications when cell coverage is unavailable. These devices will be strategically staged at service centers throughout Oregon for use during a major event, such as a wildfire emergency, to improve communication capabilities into the control center, base camp, and/or management. This equipment will also enable communication when there is a loss of it due to infrastructure failure for SCADA access, WAN, and portable radios.

Figure 61: Rapidly Deployable Cell on Wheels (COW)

In addition to the COW device, Pacific Power is currently considering other, emergency communication alternatives, such as Starlink devices, to help mitigate wildfire risk in locations where there is no cellular coverage. The Starlink device would provide a Wi-Fi hot spot connection to allow communication with the local district office and the control center. Overall, the communication equipment will improve emergency restoration activities and mitigate impacts to customers.

Vehicles

Vehicles can be a source of ignition. As discussed above, operations personnel are instructed to stay on designated roads during fire season, as feasible, and to avoid vegetation which could contact the undercarriage of parked vehicle. To further mitigate any wildfire risk associated with the use of vehicles, Pacific Power plans to convert, over time, the vehicle exhaust configuration of work trucks. Some vehicles in districts with the greatest amount of FHCA will be strategically converted. Long term, when new vehicles are purchased, Pacific Power plans to purchase trucks with a vehicle exhaust configuration which minimizes ignition risk.

Basic Personal Suppression Equipment

Personal safety is Pacific Power's priority, and the company's 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 fight 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 (or other).

Water Trailer Resources

Pacific Power has water trailers that field operations use to mitigate against wildfire risk. For clarity, these resources are not dispatched to reported fires (i.e., like a fire truck). Instead, Pacific Power resources are strategically assigned to accompany field personnel if conditions warrant. For example, if it is necessary to perform work in the FHCA during a period in which there is a Red Flag Warning, Pacific Power field operations may schedule a water trailer to join field personnel working in the field. As discussed above, the water trailer 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. In the extremely unlikely event there was an ignition, the water trailer could be used to assist in the suppression of a small fire.

8. PUBLIC SAFETY POWER SHUTOFF (PSPS) PROGRAM

Pacific Power may de-energize power lines as a preventative measure during periods of the greatest wildfire risk. This practice is referred to as "proactive de-energization" or is more commonly known as a "Public Safety Power Shutoff" or "PSPS." The decision to implement a PSPS is based on extreme weather and area conditions, including high wind speeds, low humidity, and critically dry fuels. A PSPS event is implemented as a temporary measure and is intended to supplement – not replace – existing wildfire mitigation strategies. The general process is depicted below in Figure 62.

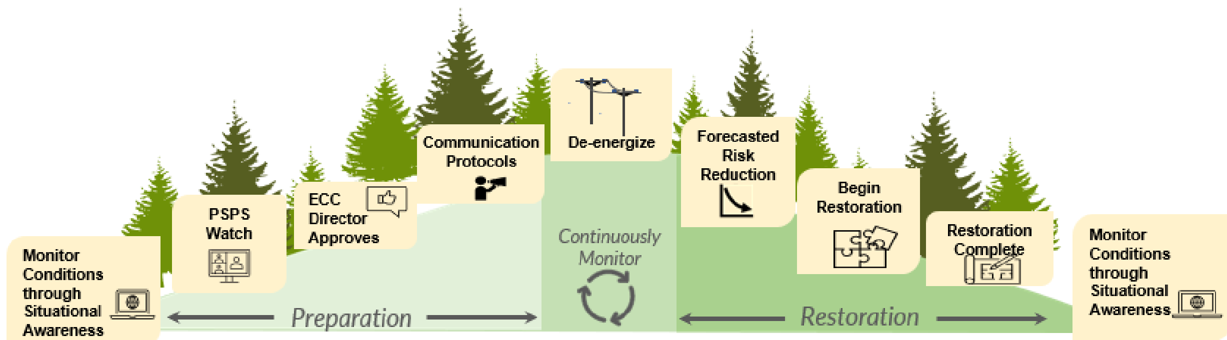


Figure 62: PSPS Overview

The following subsections describe Pacific Power's PSPS program in greater detail. Many of the program elements revolve around the successful execution of a PSPS event, while other elements bolster decision-making, mitigate the potential impact of a PSPS event, or help to avoid use of the tool altogether.

It is important to note that Pacific Power may de-energize for other types of events. For example, during emergencies, such as a significant water main break, the company may de-energize at the request of emergency response services, like the fire department. Pacific Power may also de-energize to complete planned construction work on a line to ensure the safety of construction personnel. These types of de-energizations are not considered PSPS.

8.1. INITIATION

As discussed in Section 5, situational awareness reports are generated daily during business days by the meteorology department to aid in decision-making during periods of elevated risk. During periods of extreme risk like during PSPS assessment and activation, these reports are generated daily and on weekends. They identify where fuels (dead and live vegetation) are critically dry, where and when critical fire weather conditions are expected (gusty winds and low humidity), and where and when the weather is forecast to negatively impact system performance and reliability. It is the intersection of these triggers that result in the potential for a PSPS event, as shown below in Figure 63.

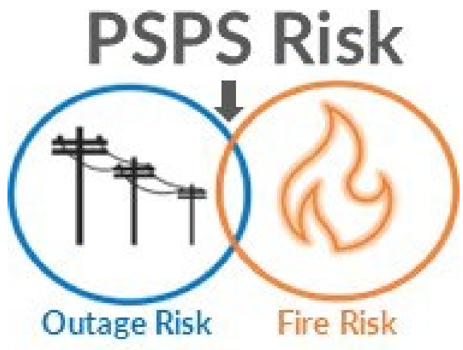


Figure 63: PSPS Assessment Methodology

8.2. ASSESSING THE POTENTIAL FOR A PSPS

As discussed above, meteorology generates a daily weather briefing that includes a system impact forecast matrix for Pacific Power's entire service territory. This matrix includes a district-level forecast of weather-related outage potential and fire risk as described in detail in Section 5 of this document. When the district fire risk is significant or extreme, meteorology will use a combination of its WRF and outage models, Technosylva's WFA-E, and subject matter expertise (as described in Section 5.4) to identify circuits of concern. Emergency management will also schedule a coordination meeting to discuss circuits of concern and to determine the appropriate operational response, up to and including PSPS. A PSPS is typically discussed and/or considered when the forecast matrix indicates a combination of wind-related outage potential and extreme wildfire risk in the same district.

8.3. DE-ENERGIZATION WATCH PROTOCOL

Pacific Power actively monitors real-time weather conditions. When real-time observations and weather forecasts indicate extreme risk, a de-energization watch protocol is initiated that includes:

- Activation of an “Emergency Coordination Center” (ECC).
- Communication with local public safety partners.
- Implementation of additional monitoring activities.

The ECC is staffed by a specialty group of company representatives who assemble during de-energization warning and implementation to provide critical support to operational resources through the collection and analysis of data. The ECC makes decisions to maintain the safety and reliability of the transmission and distribution system and helps facilitate cross-organization coordination. The ECC is led by an ECC Executive and has the support of a safety officer, a joint information team, emergency management, meteorology, and operational stakeholders representing field operations, system operations, vegetation management, engineering, and other specialties.

Upon activation of the ECC, Pacific Power emergency management gathers input from public safety partners to properly characterize and consider impacts to local communities. The ECC also sends advance notifications to the operators of pre-identified critical facilities, partner utilities, and adjacent local public safety partners. The company’s customer service team then coordinates through the ECC to confirm customer lists for the subject area to develop a communication plan for customers that may be impacted.

Local assessments of lines may occur during a PSPS watch by way of various methods depending on the accessibility of locations, the reliability of the line, area conditions and other factors. The ECC reviews several factors and may deploy crews to perform these assessments in the field or remotely monitor from the operations center.

PSPS is a temporary mitigation measure. Consistent with existing regulations and the general mandate to operate the electrical system safely, the ECC has discretion to determine when (or if) a PSPS is appropriate. Given the potential impacts to customers and communities, the ECC Executive will consider all available information, including real-time feedback and other considerations from other ECC participants, public safety partners, and field observers, to determine whether a PSPS should be executed. Additionally, the ECC Executive may decide to further refine the PSPS areas identified.

8.4. DE-ENERGIZATION PROTOCOL

When a PSPS event is initiated, an action plan is prepared to include affected location details, event timing and projected event duration. Once approved by the ECC Executive, an internal notification is sent to initiate appropriate communications to customers, critical facilities, public safety partners, regulatory organizations, large industrial customers, and required field and system operations team members. Preparations also begin for the opening of community resource centers (CRCs), if needed, and additional field resources may be deployed or staged accordingly. Conditions are continually monitored; when they no longer meet the requirement for a PSPS, the lines are patrolled and assessed for damage to begin the process of re-energization.

8.5. COMMUNICATION PROTOCOL

Pacific Power recognizes that adequate and clear communication is a key component to the successful implementation of a PSPS event, and the company will always strive to provide as much notice as practical to impacted parties. Nonetheless, PSPS decisions are made based on weather forecasts, and weather can change quickly or dramatically with little forewarning. This requires some degree of balancing in communication protocols and, accordingly, advanced notice may not always be possible.

PUBLIC SAFETY PARTNERS AND CRITICAL FACILITIES

Public safety partners, like non-emergency dispatch centers, emergency management, fire agencies, and law enforcement agencies, are an essential component to any communication plan during an event. They provide essential insight into the geographic and cultural demographics of affected areas to advise on protocols that address limited broadband access, languages, medical needs, and vision or hearing impairment. Pacific Power's initial communication with local public safety agencies starts as early as possible when weather forecasts indicate a PSPS event is possible. Typically, this occurs during a PSPS watch to allow them to prepare for operational impacts internally and mitigate any community-wide impacts that may occur because of de-energization. Collaboration with these agencies also supports impact reduction of de-energization and communication of information regarding the impacted areas and expected event duration.

Upon activation of the ECC, emergency management resources coordinate, as appropriate, with local, county, tribal, and state emergency management to provide information through the assigned representative of the agency. ECC-assigned staff provide event details including estimated timing and event duration, potential customer impacts, and GIS shapefiles that include PSPS boundaries for areas subject to de-energization. Throughout a PSPS event, Pacific Power's emergency management group maintains regular communication with local, regional, and state emergency responders, mutual assistance groups, tribal emergency managers, the state ECC through ESF-12, and other entities as applicable. The company will also support efforts to send out emergency alerts and status updates, as appropriate, until restoration efforts begin.

Critical facilities are particularly vulnerable to the impact of PSPS events. Pacific Power's emergency management maintains a list of critical facilities within its service territory. Upon activation of an ECC, they will work to establish and maintain direct contact with these facilities' emergency points of contact to provide projected PSPS timing, estimated duration, regular status updates, and restoration notifications. Additionally, the company will provide, where possible, GIS shapefiles to communications facility operators in potentially impacted areas.

During a PSPS event, Pacific Power recognizes the importance of providing additional geographic details of the affected area and plans to provide them to public safety partners through a secure web-based public safety partner portal, beginning in 2024. The public safety partner portal is expected to be a secure, map-centric application that will host information regarding critical facilities and infrastructure like GIS files for location, primary/secondary contact information, and known backup generation capabilities.

CUSTOMERS

The Pacific Power PSPS webpage[24] provides timely and detailed information regarding potential and actual PSPS events for a specific location. The website has the bandwidth to manage site traffic under extreme demand because it has implemented bandwidth capacity to a level that will allow for increased customer access while maintaining site integrity. The PSPS webpage provides visitors with an interactive map where users can input an address to see if a residence or business could be affected by a PSPS. When a potential PSPS is announced, the map is updated to show the geographic boundaries of potentially impacted areas. The boundaries will be colored yellow, or “Watch” prior to de-energization, then red or “Event” once de-energization occurs. The website is easily accessible by mobile device, and a Pacific Power ‘app’ is available for mobile devices, which enables customer access to real-time outage updates and information.

Customers with specific language needs can also contact the company’s customer care number and request to speak with an agent that speaks their preferred language. Pacific Power employs Spanish-speaking customer care professionals and contracts with a 24/7 service that provides interpretation in real-time over the phone in multiple languages and dialects. Customer care agents have received training on wildfire safety and preparedness, and PSPS-related information to facilitate a conversation between the customer and interpretive service to ensure the customer receives the wildfire safety and preparedness, or PSPS-related information they are looking for. Additional information on the company’s customer wildfire safety and preparedness engagement strategy can be found in Section 0 of this document.

Pacific Power’s communications plan also includes procedures that ensure appropriate notifications (additional if time allows) to medically vulnerable customers. The utility leverages insight from its partners and customer records to pre-identify these customers.

[24] See https://www.pacificpower.net/psps.

Upon activation of the ECC, customer care agents will attempt, time and circumstances allowing, to make personal outbound calls with known vulnerable customers.

The communication plan allows for informational updates to customers using multiple methods of communication. Direct customer notifications are made by way of outbound calls, text messaging, and email notifications. Customers will receive an outbound call, when possible, within:

- 48 hours of a potential PSPS event,
- 24 hours prior to de-energization,
- 1 to 4 hours prior to de-energization,
- At the commencement of the event,
- At the beginning of the re-energization process, and
- Upon the event conclusion.

Additional methods of notification include the use of social media sites including Facebook and X (formerly Twitter). Upon activation of the ECC, and following appropriate customer notifications, the public information officer will distribute press releases to news outlets that serve the affected areas. Regular updates across all available channels are distributed as they are available, and the public information officer will manage press inquiries as appropriate.

In making the customer notifications described above, Pacific Power provides a statement with:

- The impending PSPS execution, with information about the estimated date, time, and duration of the event.
- A 24-hour means of contact for customer inquiries, and links to pertinent PSPS websites.
- Event status updates, and re-energization expectation notices.

NOTIFICATION TIMING

When there is a potential PSPS event forecast, customers and local government representatives will be provided with advanced notice; if feasible, notifications will begin 72 or 48 hours in advance of a potential de-energization event. If this is not possible due to rapidly changing weather conditions, or 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 because customers 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 given that the company's fundamental business objective is to keep the grid energized except under the most extreme conditions.

Table 25 below illustrates Pacific Power's planned PSPS notification timeline for notifications sent to customers, public safety partners and operators of critical facilities. Timelines may be reduced if rapidly changing conditions do not allow for advance notification consistent with OAR 860-300-0050. In these cases, the company will make all notifications as promptly as possible.

Table 25: PSPS Notification Timeline Summary

PSPS Notification Timeline and Summary	
48-72 Hours Prior	De-energization Warning to Public Safety Partners & Operators of Critical Facilities
24-48 Hours Prior	De-energization Warning
1-4 Hours Prior	De-energization Imminent / Begins
Re-energization Begins	Re-energization Begins
Re-energization Completed	Re-energization Completed
Cancellation of Event	De-energization Event Canceled *(if needed)*
Status Updates	Every 24 hours during event *(if needed)*

8.6. COMMUNITY RESOURCE CENTERS

Pacific Power is aware of the potential impacts of PSPS events to all customers, businesses, and communities and plans to provide community support through Community Resource Centers (CRCs). By taking advantage of established relationships with community and public safety partners, the company may activate a CRC in an impacted area, to give community members and businesses access to items that may be affected by the interruption of electrical service. The services, which vary across CRCs, may include:

- Potable water,
- Shelter from hazardous environment,
- Air conditioning,
- Seating and tables,
- Restroom facilities,
- Refrigeration for medicine and/or baby needs,
- Interior and area lighting,
- On-site security,
- Communications including internet, Wi-Fi, cellular access, and satellite phone,
- Television and radio,
- On-site medical support (where available),
- Charging stations for cellular devices, radios, and computers.

CRCs adhere to all existing local, county, state or federal public health orders and will have personal protective equipment on site and available to customers if needed. Local emergency management and community-based organizations will be notified of CRCs as appropriate and with advanced notice, three days prior to the event, when possible.

CRC activation timing, protocols, and locations are discussed with area emergency management and community-based organizations during emergency management workshops and tabletop exercises. With the elimination of PSPS zones, Pacific Power has concluded that pre-identification of CRCs is not necessary. Nonetheless, depending on the needs of its public safety partners as identified in workshops, tabletop exercises, and other events (described at length in Section 0), CRC locations may be pre-identified. Table 26 below lists brick-and-mortar CRC locations that have been identified in Oregon.

Table 26: Brick and Mortar Community Resource Centers

CRC	General Area	Address	County
Glendale Elementary School	Glendale	100 Pacific Avenue Glendale, OR	Douglas
Tri-City Fire Department	Riddle Myrtle Creek	140 S Old Pacific Hwy Myrtle Creek, OR	Douglas
Winchester	Winchester	780 NE Garden Valley Blvd Roseburg, OR	Douglas
Columbia Gorge Community College	Hood River	1730 College Way Hood River, OR 97301	Hood River
Greenspring's Fire Station	Cascades-Siskiyou	11471 OR-66 Ashland OR 97520	Jackson
Shady Cove Library	Shady Cove	22477 OR-62 Shady Cove, OR 97539	Jackson
Shady Cove City Hall	Shady Cove	22451 OR-62 Shady Cove, OR 97539	Jackson
Patrick Elementary School	Fielder Creek and South Rogue River	1500 2nd Ave Gold Hill, OR 97525	Jackson
Selma Community Center	Cave Junction	18248 Redwood Hwy Selma, Oregon 97538	Josephine
Illinois Valley High School	Cave Junction	625 E River St Cave Junction, OR 97523	Josephine
Bear Hotel	South Rogue River	2101 NE Spalding Ave. Grants Pass, OR 97526	Josephine
Sportsman Park	South Rogue River	7407 Highland Ave. Grants Pass, OR 97526	Josephine
Redwood Christian Center	South Rogue River	4995 Redwood Ave Grants Pass, OR 97527	Josephine
Jerome Prairie Transition Center	Jerome Prairie	2555 Walnut Ave Grants Pass, OR 97527	Josephine
Jerome Prairie Community Hall	Jerome Prairie	5368 Redwood Ave. Grants Pass, OR 97527	Josephine
Jerome Prairie Bible Center	Jerome Prairie	2564 Walnut Ave Grants Pass, OR 97527	Josephine
Merlin Community Park	Merlin	100 Acorn St, Merlin, OR 97532	Josephine
Fleming Middle School	Merlin	6001 Monument Dr, Grants Pass, OR 97526	Josephine
Manzanita Elementary School	Merlin	310 San Francisco St, Grants Pass, OR 97526	Josephine
Sunny Wolf Charter School	Glendale	100 Ruth Ave, Wolf Creek, OR 97497	Josephine
Wolf Creek Inn, Hugo	Glendale	100 Front St, Wolf Creek, OR 97497	Josephine
Glendale Elementary	Glendale	100 Pacific Avenue, Glendale, OR 97422	Josephine

These brick-and-mortar locations are also shown in Figure 64 below.

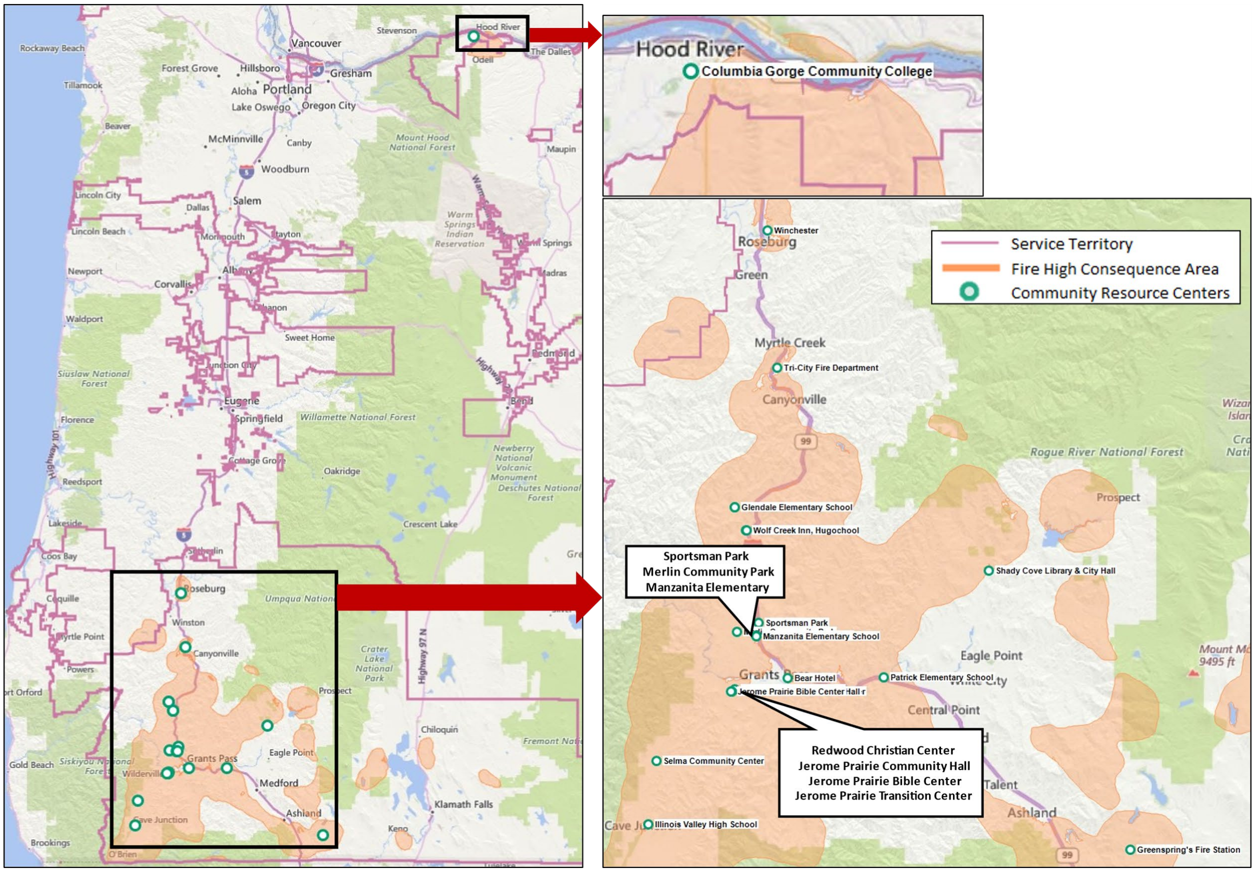


Figure 64: Brick and Mortar CRC Locations in Oregon

When it is necessary to activate CRCs in locations that have not been pre-identified and/ or are temporary, siting decisions are made with close coordination between Pacific Power and its public safety partners. Depending on the location of the PSPS and community needs, a temporary CRC could be activated in a location that has not been pre-identified. If an adequate physical facility does not exist, Pacific Power may engage a logistics vendor to stand up a CRC in a large self-contained tent to provide resources. Additionally, CRCs may also be collocated with county services like shelters or PODs.


Figure 65: Example of a Temporary CRC

8.7. RE-ENERGIZATION

As described in Section 8.4 above, local conditions are continually monitored during an event. Based on forecasted risk reduction, Pacific Power may begin staging resources to expedite restoration, Then, when local conditions subside consistent with the forecasted reduction in risk, restoration activities officially begin. The general steps of restoration are depicted below in Figure 66.

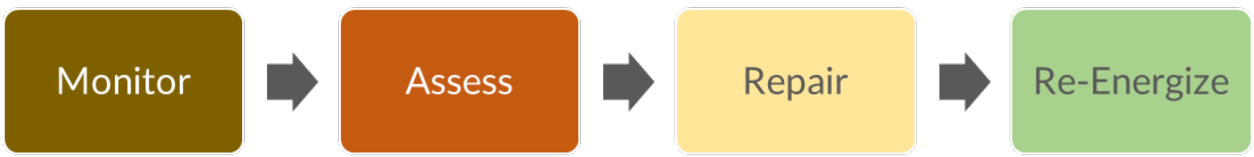


Figure 66: General Re-Energization Process

Once the local and forecasted conditions are favorable to reenergize and no new risk(s) have been identified, field personnel begin assessing the deenergized circuits through ground or air patrols. Power lines that have been deenergized during a PSPS event have been exposed to strong winds and the potential for damage. In addition, even after the wind has dropped to levels low enough to support a decision to re-energize, fire weather conditions typically remain elevated. Therefore, before reenergizing a line, post-event assessments are completed to determine whether any damage has occurred to the line and/ or substation that needs to be corrected prior to reenergization (e.g., line down, broken crossarms, tree through line, and/ or tree branches or other items blown into the line). Field personnel report any damage identified to Pacific Power's facilities to the ECC where it is tracked. If issues are discovered, the necessary repairs are made within an appropriate corrective time-period.

While all lines and facilities (e.g., substations) deenergized as part of a PSPS event are assessed, a step restoration process is leveraged where possible so that power to customers may be restored as the assessments progress instead of waiting for the assessment of the entire impacted area to complete prior to re-energization. While not to scale or representative of an actual event, this concept is visually depicted in Figure 67 Figure 67 below.

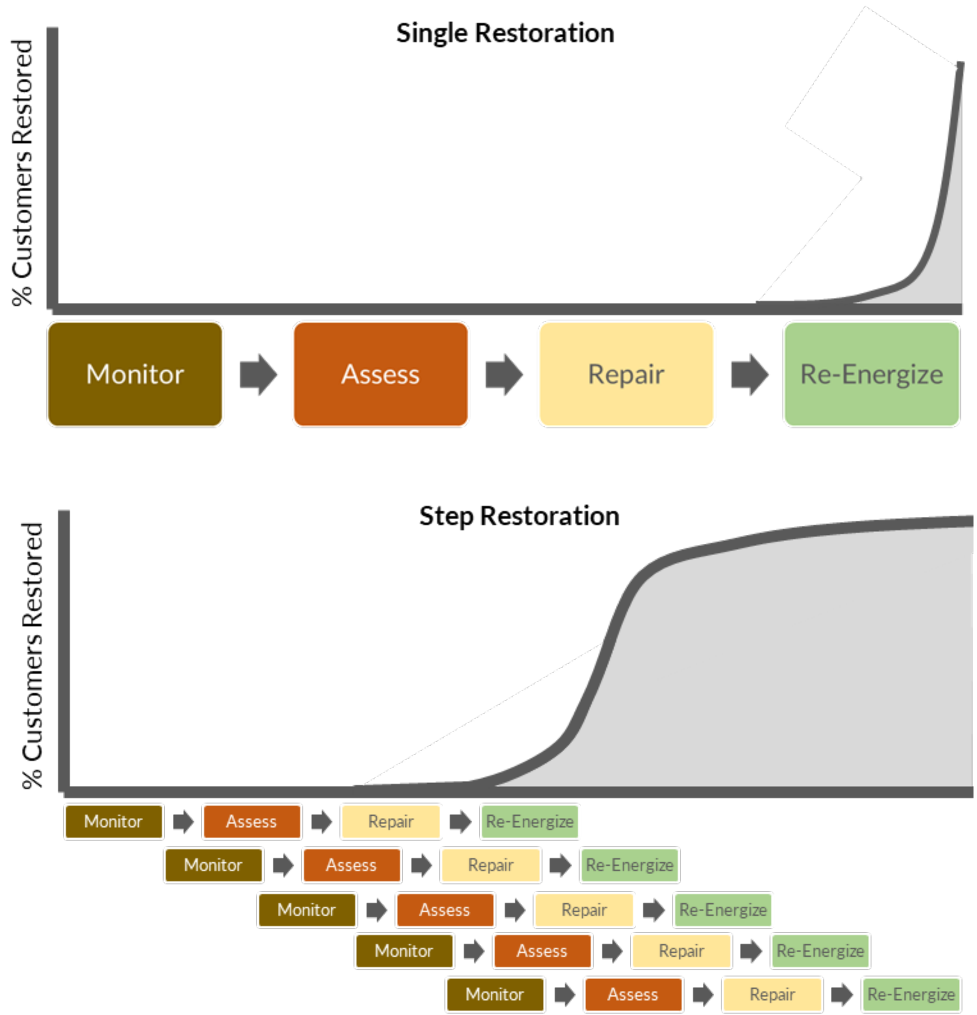


Figure 67: Visual Depiction of Step Restoration

Wherever possible, Pacific Power also works with emergency and public safety partners to identify critical customers for prioritization. After the line patrol and facility inspection is completed, the impacted circuits/ portions of circuits are reenergized, and the date and time of reenergization is logged. Once service is restored to all customers impacted by the PSPS event, the event concludes.

8.8. EXPERIENCE

Pacific Power plans to continuously improve all aspects of its emergency management practices. In 2023, Pacific Power did not implement a PSPS in Oregon. From the company's multi-year, overall experience, it has identified four general opportunities for improvement to its Public Safety Power Shutoff Program moving forward. These include:

- **Broaden public outreach and engagement.** Pacific Power plans to expand its communication and overall preparedness as appropriate to ensure adequate public outreach and engagement regarding PSPS and wildfire safety. As noted above, more detailed information on the company's customer wildfire safety and preparedness engagement strategy can be found in Section 0 of this document.
- **Strategize community resource center locations.** During the 2022 PSPS event, the location of the Sweet Home CRC was determined by collaboration with local emergency management. In this case, the CRC was stood up adjacent to an overnight shelter for residents experiencing houselessness, which worked well when the CRC was closed. The company will continue to emphasize CRC planning during workshops and tabletop exercises, and, during events, it will work with local public safety partners to better identify the needs of communities impacted.
- **Streamline GIS and information sources.** Due to the dynamic nature of a PSPS event, there is a need to manually update multiple sources of information and GIS layers among various internal platforms. Pacific Power plans to leverage its 2023 public safety partner coordination plan to streamline and better align GIS layers and information sources to communicate information quickly. For instance, Pacific Power is currently working to develop a secure, web-based public safety partner portal where critical information can be shared with its partners during a PSPS event. More information about this public safety partner portal can be found in Section 9.8 of this document.
- **Internal communication and coordination.** Most documents, communication protocols, and processes have worked well. Nevertheless, there is still an opportunity to build out new tracking tools, documents, and training within the existing response structure. To that end, in 2023 a novel tracking tool for meetings and other events was developed and implemented and Pacific Power has begun to look at building out additional situational awareness tools.

Additionally, from its experience in 2022 specifically, the company identified and recommended actions to evolve its processes accordingly. These are summarized in Table 27 below:

Table 27: Summary of 2022 PSPS Experiences

Description of Experience	Recommended Action	Status
Multiple points of contact among partners resulted in missed opportunities for communication with partners.	• Update documentation and incident action plan to include a single point of contact for partners.	• **Implemented**. Pacific Power emergency management has established service territories for its emergency managers to create a single point of contact for partners.
Critical facility (customer) identification (GIS information).	• Complete implementation of the Public Safety Partner Portal. • Identify steps for producing shapefiles with critical customer information and identify who should receive them.	• The Public Safety Partner Portal is on track for delivery in the first quarter of 2024.
Inconsistent documentation created potential for confusion internally and external partners.	• Improve documentation consistency. • Task Information Management Specialist (IM) or Joint Information System (JIS) with ensuring that all sources of information match. • Include details on who is responsible for what information.	• **Implemented**. Joint information system training has been given to corporate communications, Regional Business Managers (RBMs), customer service, and regulatory on the documentation process to include roles and responsibilities.
Feedback from partners.	• Provide more outreach and training on PSPS to partners.	• Expanded PSPS outreach and workshops for all OR counties except one (noted in MBR report)

9. PUBLIC SAFETY PARTNER COORDINATION STRATEGY

Pacific Power takes a multi-step approach to coordination with its public safety partners on wildfire mitigation and PSPS preparedness, as shown in Figure 68 below.

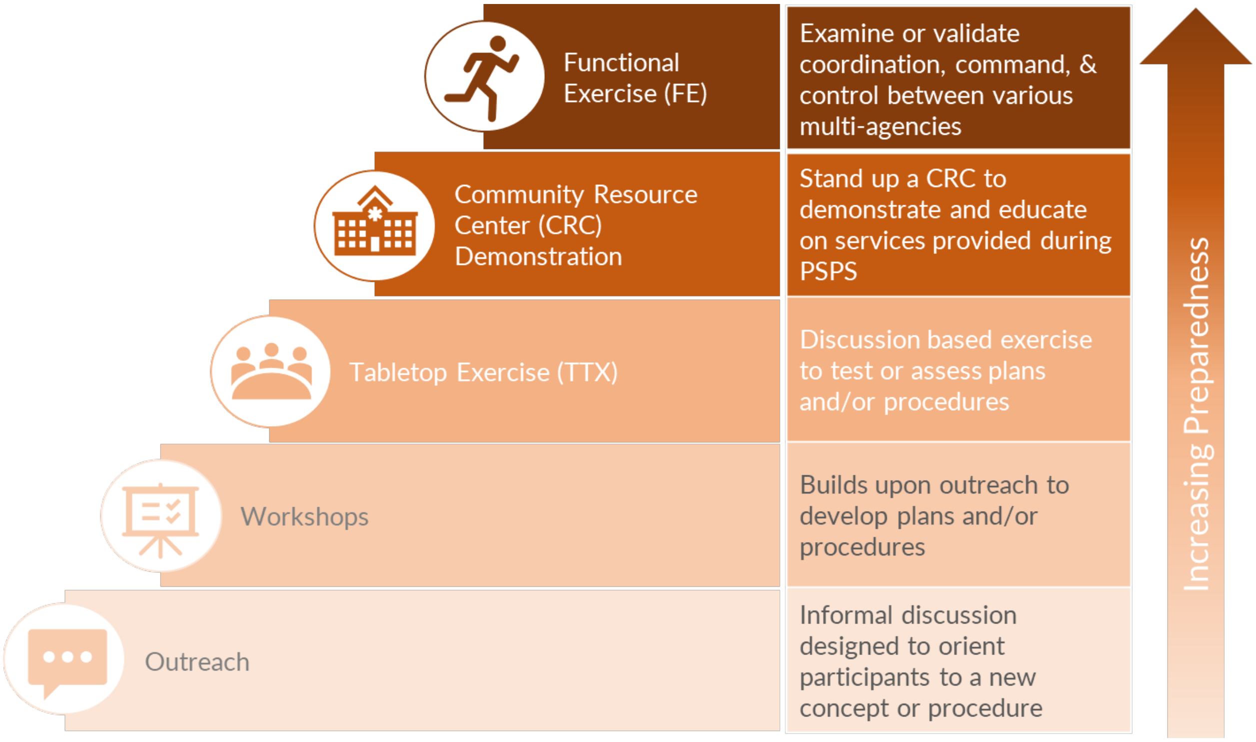


Figure 68: PSPS Preparedness Strategy

As a part of this strategy, each element builds upon the previous step to increase overall preparedness. They include outreach, workshops, Tabletop Exercises (TTXs), Community Resource Center (CRC) demonstrations, and functional exercises (FEs) as described in more detail in the following subsections.

9.1. GENERAL OUTREACH

Pacific Power participates in multiple public safety partner meetings and workshops throughout the calendar year across its service territory. Meetings include monthly, quarterly, and annual County and State Emergency Management partner meetings, in addition to pre- and post-fire season collaboration meetings with local, state, and federal fire suppression agencies. These informal discussions are designed to orient participants to a new concept or procedure and continue fostering key working relationships. Additionally, Pacific Power provides an annual customer webinar, described at greater length in Section 10.5, that provides additional information about PSPS practices that is displayed prominently on the Wildfire Safety website.

9.2. WORKSHOPS

Workshops are more local, targeted discussions that build upon general outreach to further compare and refine plans, streamline processes, and confirm capabilities (such as customer outreach, critical facilities, and CRC locations and operations) with local public safety partners. In 2022, the company did not conduct workshops as part of its outreach outside the FHCA. In 2023 and beyond, however, it anticipates targeting workshop locations outside of the FHCA and leveraging them to bring other communities and public safety partners up to speed.

9.3. TABLETOP EXERCISES

Pacific Power facilitates annual discussion-based and functional tabletop exercises to develop awareness of PSPS planning and procedures. These exercises aim to facilitate public and private sector coordination, validate communications protocols, and verify capability to support communities during extreme risk events through mitigation actions such as the deployment of community resource centers. Additionally, the exercises include the collective identification of critical infrastructure at the county level to better inform restoration planning and notifications. Pacific Power collects after-action reports from exercises and real-world events involving wildfire safety and Public Safety Power Shutoff. The after-action reports request feedback on areas for improvement, potential corrective actions and suggestions for plan or procedure development. The company considers suggestions for inclusion in a comprehensive plan that is subsequently shared with the appropriate public safety partners.

9.4. COMMUNITY RESOURCE CENTER DEMONSTRATIONS

Pacific Power may provide a public demonstration of a Community Resource Center (CRC) prior to the start of wildfire season. This public event provides an opportunity for members of the public, as well as public safety partners, to learn about the type of services offered at a CRC during a PSPS event.

9.5. FUNCTIONAL EXERCISE (FE)

Functional Exercises (FE) are the last step in PSPS preparedness. Pacific Power coordinates these exercises to examine or validate coordination, command, and control between various agencies. Unlike TTXs or workshops, which are discussion based, these exercises are larger scale, last much longer (e.g., multiple days), require significantly more planning and coordination, and include deployment of resources to practice protocols and processes. A functional exercise requires that part of the plan is executed. Examples relevant to a PSPS FE might include performing customer calls or updating websites. To be successful, functional exercises require that foundational planning like workshops and TTXs be complete, and formal plans to be in place. Currently, Pacific Power is not planning to conduct a functional exercise in Oregon in 2024. Pacific Power does expect to leverage its experience conducting functional exercises in other states with more mature PSPS programs and incorporate functional exercises in Oregon in the future as needed.

9.6. 2023 ACTIVITIES

In 2022, the primary focus of Pacific Power's public safety partner coordination strategy was on areas and counties located within the FHCA. In 2023, Pacific Power expanded PSPS preparedness to conduct workshops targeting counties located outside of the FHCA. Additionally, instead of conducting multiple small TTXs, like in 2022, the company held two regional TTXs in 2023 to improve efficiency and enhance broader coordination and collaboration. While these tabletops still targeted certain counties, the company encouraged expanding participation by inviting officials from adjacent counties. Table 28 and Figure 69 below summarizes the company's 2023 planned and completed activities.

Table 28: 2023 Completed Workshops and Exercises

Planned Activity	General Location[25]	Target Counties[26]	Planned Timeframe	Completed Date
Workshop 1	Southeast OR (Klamath Falls)	Klamath, Lake	March 2023	Combined with other engagement[27]
Workshop 2	Central OR (Bend)	Deschutes, Jefferson, Crook	March 2023	March 15, 2023
Workshop 3	Willamette Valley (Corvallis)	Lane, Marion, Linn, Benton, Polk	March 2023	March 1, 2023
Workshop 4	Eastern OR (Virtual Meeting)	Umatilla, Wallowa, Sherman, Gilliam, Morrow	April 2023	September 19, 2023
Workshop 5	Southern OR Coast (Coquille)	Coos	April 2023	April 19, 2023
Workshop 6	OR Coast (Lincoln City)	Lincoln, Clatsop	April 2023	May 12, 2023
Regional TTX 1	Southern OR (Grants Pass)	Douglas, Jackson, Josephine	April 2023	April 5, 2023
Regional TTX 2	Northern OR (Hood River/Wasco)	Hood River, Wasco	April 2023	April 26, 2023
CRC Demonstration	Northern OR (Hood River)	Hood River, Wasco	April 2023	Deferred to 2024

[25] Pacific Power outlined general locations in the 2023 WMP and then worked with public safety partners to select the most appropriate location and dates for these activities.
[26] While the target counties informed the plan and strategy, Pacific Power did not limit participation to the event.
[27] Combined with Fire Year briefing hosted by Oregon Living with Fire on May 5, 2023, which county emergency managers.

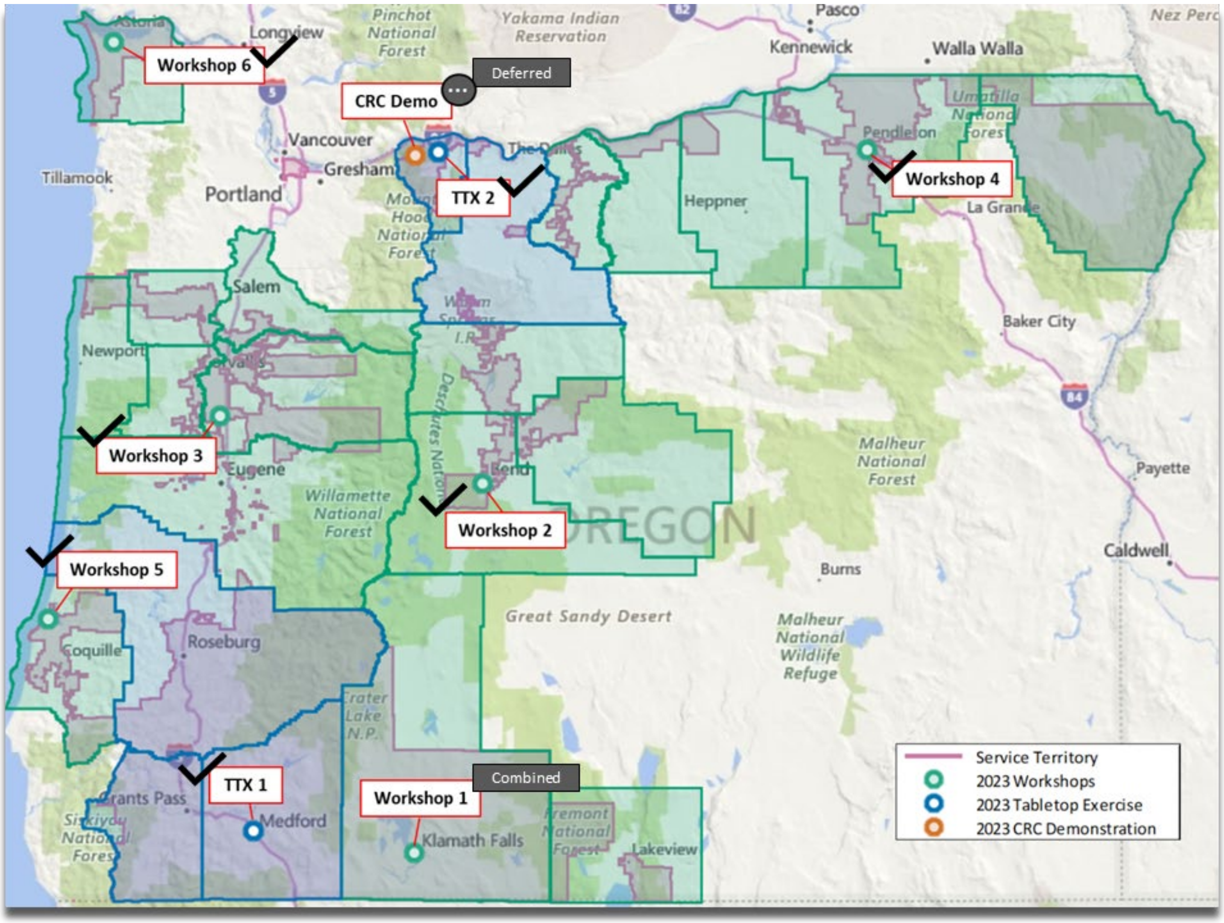


Figure 69: 2023 Completed Workshops and Exercises

In addition to executing the 2023 planned activities, Pacific Power also participated in various other workshops, conference, and discussions to ensure coordination and preparedness with public safety partners, state agencies, and other utilities. Examples include the Oregon Joint Use Association (OJUA) spring training conducted on April 27, 2023, the Fire Year briefing hosted by Oregon Living with Fire on May 5, 2023, and the Lincoln County Readiness Fair held on September 9, 2023.

9.7. 2024 EMERGENCY PREPAREDNESS AND EXERCISE PLAN

In 2024 and beyond, the company plans to continue building upon previous years' experience to engage and coordinate with public safety partners ahead of fire season. Based on the company's 2023 experience with expanded preparedness, planning, in collaboration with public safety partners, is most effective when completed during the first quarter of the year. Therefore, Pacific Power intends to solicit input from public safety partners in the first quarter of 2024 to firm up the details and schedule of each workshop and exercise. Table 29 below represents the company's general outreach plan, subject to feedback. Overall, the company intends to complete outreach by the end of June 2024, pending public safety partner preference and availability.

Table 29: 2024 General Workshop and Exercise Plan

Planned Activity	General Location[28]	Target Counties[29]
Workshop 1	Southeast OR (Klamath Falls)	Klamath, Lake
Workshop 2	Central OR (Bend)	Deschutes, Jefferson, Crook
Workshop 3	Willamette Valley (Albany)	Lane, Marion, Linn, Benton, Polk
Workshop 4	Eastern OR (Pendleton)	Umatilla, Wallowa, Sherman, Gilliam, Morrow
Workshop 5	Southern OR Coast (Coos Bay)	Coos
Workshop 6	OR Coast (Astoria)	Lincoln, Clatsop
Regional TTX 1	Southern OR (Medford)	Douglas, Jackson, Josephine
Regional TTX 2	Northern OR (Hood River)	Hood River, Wasco
CRC Demonstration	TBD	TBD

In 2023, Pacific Power developed a template and mechanism to begin tracking feedback and action items from public safety partners on its outreach strategy. This template can be found in Appendix G – Public Safety Partner Event Registry Template. Looking forward to 2024 and beyond, Pacific Power plans to document its interactions with public safety partners, their feedback, and resulting action item(s) using this new template.

28 Pacific Power plans to work with public safety partners to select the most appropriate location for these activities. Currently, the locations are depicted as general locations and should be considered estimates.

29 While the target counties that informed the plan and strategy are listed in the table, Pacific Power may invite public safety partners and officials from adjacent counties as needed.

9.8. PUBLIC SAFETY PARTNER PORTAL

During a PSPS event, Pacific Power recognizes the importance of providing additional geographical details of the affected area. Therefore, in addition to the preparation strategy described above, Pacific Power is currently working to develop a secure, web-based portal consistent with the requirements in OAR 860-300-0060[30] where it can share critical customer information with Public Safety Partners during a PSPS event. Once completed, the Public Safety Partner portal will be a secure, map-centric application that will host critical GIS files, as well as information regarding critical facilities and infrastructure like primary/secondary contact information and known backup generation capabilities. In addition to enhancing coordination with local public safety partners, the portal will also enhance Pacific Power's capabilities to evaluate, communicate with, and prioritize restoration of critical facilities that provide essential services for public safety. The company started the project in 2022 and will launch in 2024 as depicted in Figure 70 below.

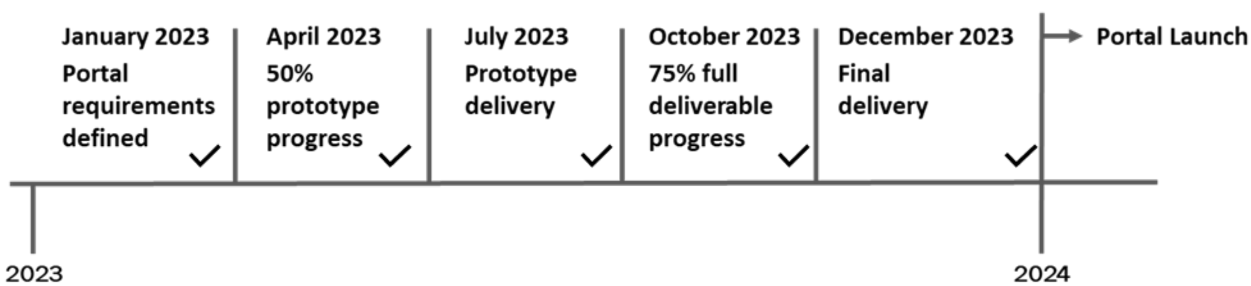


Figure 70: Public Safety Partner Portal Project Timeline

30 OAR 360-300-0060 requires that Public Utilities create a web-based portal for use during PSPS events by March 31, 2024.

10. WILDFIRE SAFETY & PREPAREDNESS ENGAGEMENT STRATEGY

Pacific Power employs a multifaceted approach to support community engagement and outreach with the goal of providing clear, actionable, and timely information to customers, community stakeholders and regulators. Over the past several years, the company has engaged customers and the general public throughout its three-state service area on wildfire safety and preparedness through a variety of tactics including webinars, in-person forums and booth events, targeted paid advertising campaigns, informational videos featuring company subject matter experts, press engagement, distributed print materials, infographics, social media updates, and direct communication through: bill messages, emails and website content, among other communication channels. The wildfire safety and preparedness community engagement plan will continue to evolve year-over-year as customer and stakeholder feedback and regulatory guidance is incorporated. Pacific Power maintains an awareness and engagement strategy that is flexible and allows for dynamic tactics, informed by customer survey data, community stakeholder input and community needs. Overall, Pacific Power's plan includes information that can be heard, watched, and read in a variety of ways with the goal of accessibility and understandability.

10.1. AWARENESS AND ENGAGEMENT CAMPAIGN

For the past several years, the company has deployed some form of paid media campaign to raise awareness and action on wildfire safety and preparedness. The 2023 wildfire safety and awareness paid advertising campaign, which launched March 20, 2023, and concluded October 1, 2023, included radio spots, digital over-the-top (OTT) pre-roll video ads (Hulu, Pluto TV, Roku, etc.), digital audio ads (Spotify, Pandora, etc.), display ads (search and web banners), and social media static and video ads (Facebook, Instagram, and YouTube) – each delivered in English and Spanish.

Metropolitan Statistical Areas in Oregon targeted through the paid campaign included Bend, Medford, Eugene, Pendleton, Hood River, Klamath Falls, Roseburg, Coos Bay, and East Portland-Metro. The campaign focused on four main topics: personal preparedness and safety, PSPS, leadership and vision, and investments the company is making to reduce wildfire risk, specifically grid hardening. A breakdown of media type, target area, and language are shown in Table 30 below.

Table 30: 2023 Media Campaign Summary

Media Type	Target Area	Language
Radio	Bend Medford Eugene Pendleton Hood River Klamath Falls	English Spanish (Medford only)
Cable	Medford Klamath Falls Roseburg Coos Bay	English
Over The Top (Ott)	Bend Medford Eugene E. Portland Metro	English
Pre-Roll	Bend Medford Eugene E. Portland Metro	English Spanish
Display	Bend Medford Eugene E. Portland Metro	English Spanish
Social Media	Bend Medford Eugene E. Portland Metro	English Spanish
Digital Audio	Bend Medford Eugene E. Portland Metro	English

The call-to-action in each campaign vertical compelled the audience to visit Pacific Power's wildfire safety and preparedness online resources. In 2023, the various ads across multiple channels collectively received 12,407,482 impressions and 57,713 clicks to company-hosted wildfire safety and preparedness informational webpages.

Engaging with local and regional news media outlets is another key component of the awareness and engagement campaign. Each year prior to fire season, Pacific Power distributes updated wildfire safety information and information on the company's WMP to press outlets across its service area as an additional low-cost outreach method. During the 2023 wildfire season, company wildfire safety and mitigation subject matter experts also provided eight interviews on the topics of PSPS and wildfire mitigation.

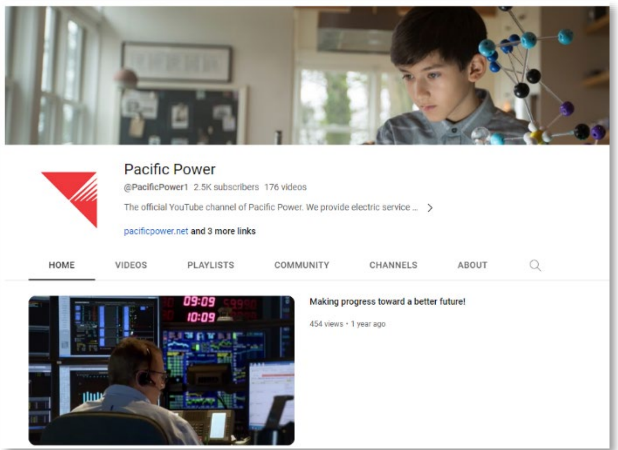


Figure 71: Sample YouTube Content

In addition to paid and earned (news media engagement) awareness and engagement strategies, Pacific Power also communicates to customers about wildfire safety and preparedness through channels it owns or manages, as shown in Figure 71. Bill messages, website and social media updates, emails, texts, automated phone calls are also an additional low cost means to reach customers.

10.2. SUPPORT COLLATERAL

Pacific Power has developed several print and digital wildfire safety and preparedness collateral pieces including factsheets, flyers, brochures, infographics, and safety checklists. These items are accessible through the company wildfire safety webpages and are utilized at public meetings and community events to describe PSPS (its necessity, considerations and what to expect throughout the event, etc.), and to provide general information on emergency kits/plans and preparation checklists, among other topics.

The Pacific Power communications team updates these materials annually to ensure the information is relevant, accessible, and actionable. Spanish versions of each piece of collateral are also made available. Some examples of support collateral are shown in Figure 72.

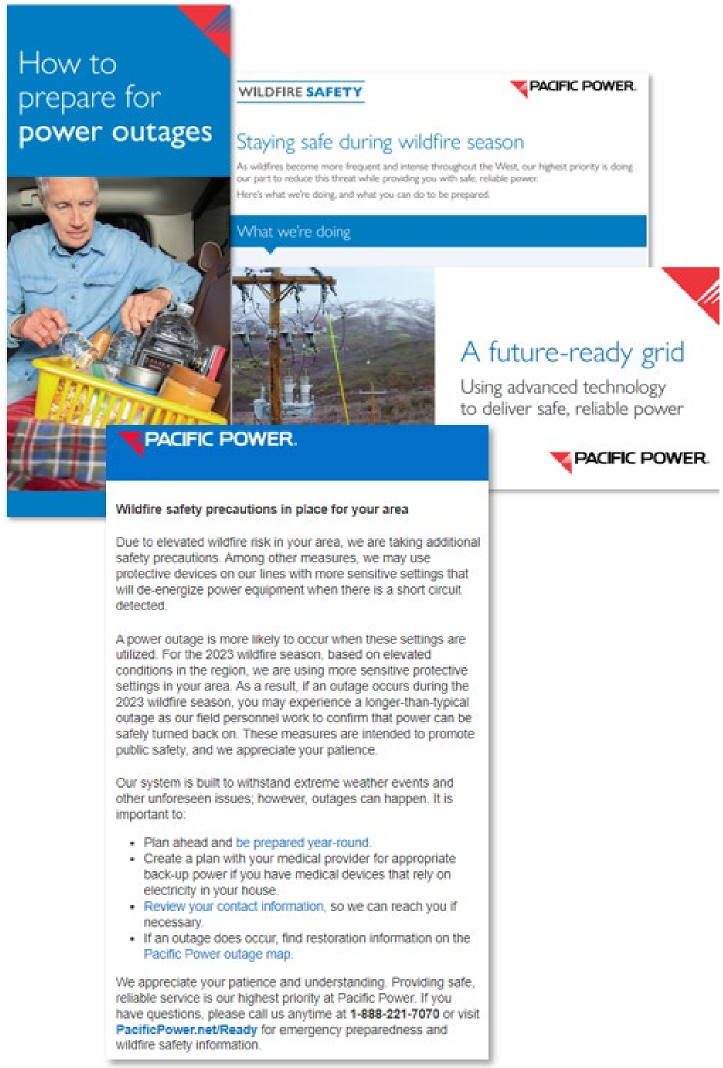


Figure 72: Sample Support Collateral

Additionally, the company engages customers as needed via direct communications like email. For instance, beginning in 2023, during periods of elevated risk, modified operational settings (described in greater detail in Section 6, System Operations) may be implemented in some areas. Consistent with OAR 860-300-0020 (1)(e), customers that are impacted by implementation of these settings are sent a notification via email or paper letter, depending on their communication preferences, when this occurs. An example of support collateral for customer notification of implementation of modified operational settings is included in Figure 72.

Going forward into 2024 and beyond, Pacific Power plans to align its communication regarding modified operational settings with its peer utilities.

10.3. CUSTOMER SERVICE TRAINING

Customer care agents have received training on wildfire safety and preparedness and PSPS-related information to ensure that customers who call in looking for information about wildfire safety and preparedness or PSPS get information they are looking for. Additionally, customers with specific language needs can also contact the company's customer care number and request to speak with an agent that speaks their preferred language. Pacific Power employs Spanish-speaking customer care professionals and contracts with a 24/7 service that provides interpretation in real-time over the phone in multiple languages and dialects.

In 2022, Pacific Power established a process to track customer calls regarding wildfire safety, wildfire preparedness, and other wildfire concerns. This process allowed customer care specialists to select the term 'wildfire' from a drop-down menu at the conclusion of calls. In 2023, the company received 294 calls from customers regarding wildfire safety. Of those, 233 occurred at the peak of fire season (August).

10.4. WILDFIRE SAFETY, PREPAREDNESS, AND PSPS WEBPAGES

The Pacific Power website provides robust and comprehensive information on company wildfire mitigation programs, general wildfire safety, PSPS information, and more. In 2022, the company launched updated wildfire safety webpages to improve customer experience and allow for improved accessibility to wildfire-related information. The page refreshes include a new

Figure 73: Wildfire Safety Infographic

infographic depicted in Figure 73 that demonstrates the work in progress to improve the safety and reliability of the grid.

Additionally, the page was updated with embedded videos highlighting the work Pacific Power will complete to improve the system, increase situational awareness, and prepare for events that may result in outage activity.

The wildfire safety webpages were also updated in early 2022 to include a 1-to-1 translated Spanish wildfire safety pages (Figure 74). This includes a frequently asked questions section, links to public safety power shutoff maps and information, and resources including public safety power shutoff and wildfire preparedness brochures.

Figure 74: English to Spanish Webpage Translation

Various resources and tools for community preparedness can be found on the Pacific Power wildfire mitigation webpage.[31] Prompts for customers to update contact information are displayed prominently on the page. Guides and checklists for creating an emergency plan/outage kit are easily accessible. The wildfire safety webpages also include links to the WMP, as well as links to webinars and videos describing key components of the plan. Overall, site visitors have a variety of ways to consume and engage with wildfire safety and preparedness information, as shown below in Figure 75.

31 www.pacificpower.net/wildfiresafety

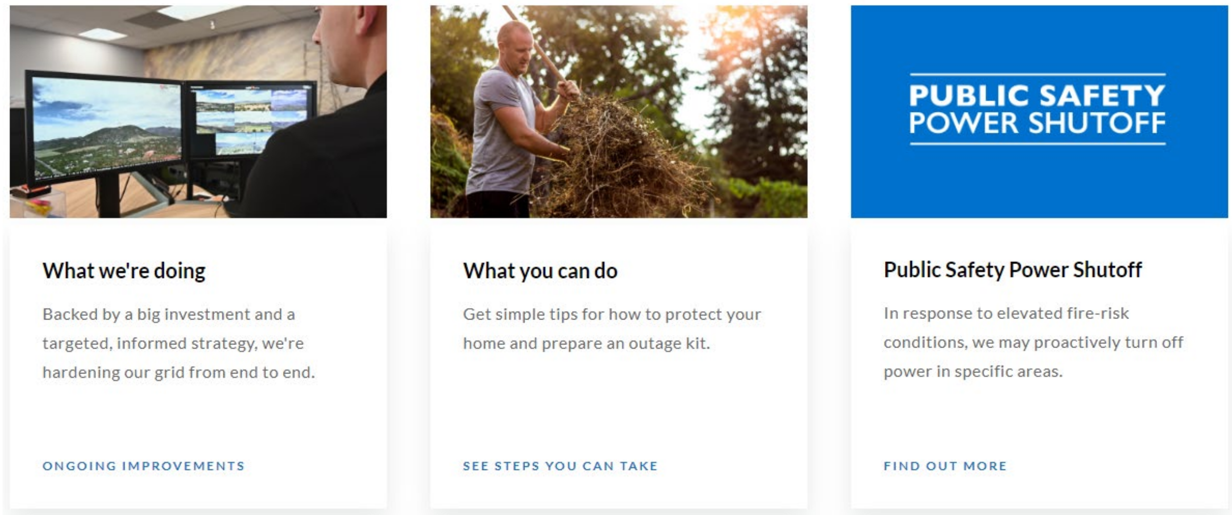


Figure 75: Sample Website Material

Additionally, the Pacific Power Public Safety Power Shutoff webpage provides educational material on PSPS. It describes why a PSPS would happen, includes details of conditions monitored prior to executing a PSPS, and on how customers can prepare. Information on how customers will be notified, what to expect during an event, and about the service restoration process if a PSPS is deemed necessary are detailed on the webpage. There is also an interactive map of PSPS areas (shown in Figure 76) that provides a visualization of whether the company is considering a PSPS, and which areas might be affected if one is necessary.

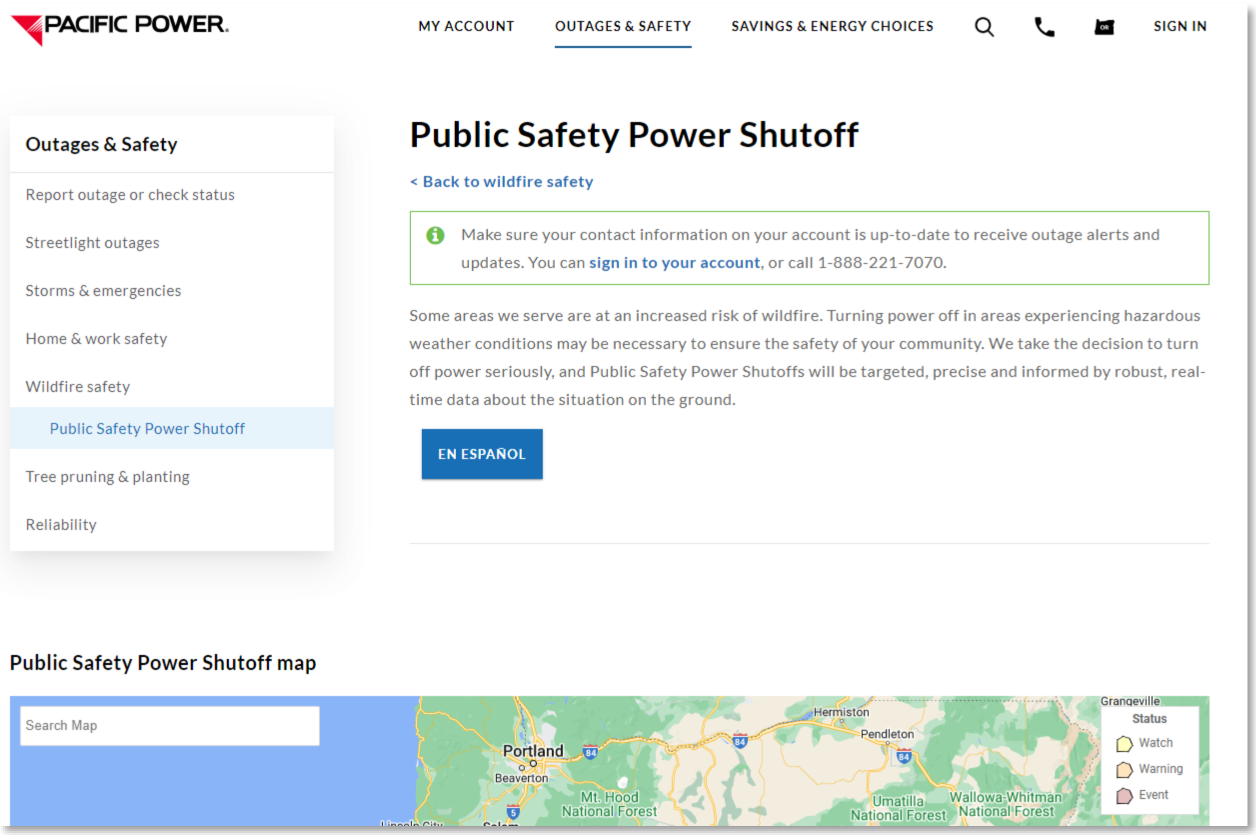


Figure 76: Pacific Power PSPS Webpage

To ensure that the website information is provided in identified prevalent languages, the PSPS webpage has a message in nine languages – Chinese traditional, Chinese simplified, Tagalog, Vietnamese, Mixteco, Zapoteco, Hmong, German and Spanish - that states "A customer care agent can speak with you about wildfire safety and preparedness. Please call 888-221-7070." The company will continue to work with Public Safety Partners and Community-Based Organizations (CBOs) to determine if additional languages should be included.

Additionally, the webpages have the capacity to manage site traffic under extreme demand because the company has implemented the bandwidth to allow for increased customer access without compromising site integrity. For example, the Wildfire Safety and PSPS webpages were successfully visited by over 14,000 people during the 2022 PSPS event without issue.

10.5. WEBINARS AND COMMUNITY FORUMS

Pacific Power also hosts an annual webinar that provides an overview of the company's wildfire mitigation program and strategies. Among other items, key mitigation topics addressed in the webinar include situational awareness capabilities, system hardening investments, the PSPS process, and general emergency preparedness. The webinar brings to focus how the company engages with local communities and public safety partners on wildfire safety. It also serves as a forum for customers, community stakeholders, and the public-at-large to ask questions during the live stream. The 2023 webinar was held June 28, 2023, and posted to the Pacific Power website and YouTube channel.[32]

Pacific Power is a public utility, and as such, aims to develop a WMP that aligns with public interests. In 2023, consistent with 860-300-0040, the company conducted a series of seven in-person, live-streamed public engagement events designed to communicate an overview of its 2023 WMPs, provide an environment for direct questions and answers, and foster public engagement in the company's overall wildfire mitigation planning processes.

Figure 77: 2023 WMP Booth in Philomath

In sum, a total of four in-person community engagement forums and three booth events were hosted throughout the company's service territory to broaden the scope of engagement and awareness of the company's WMP. Table 31 below provides information on the location, date, event type, and attendance details for these events.

32 Oregon Wildfire Safety Webinar | June 2023 - YouTube

Table 31: 2023 Forum Details and Attendance

Community	Date	Event Type	Total Attendees (In Person + Virtual)	Virtual Attendees
Cannon Beach	September, 2023	Booth Event	17	1
Philomath	September, 2023	Booth Event	12	0
The Dalles	September, 2023	Booth Event	12	0
Hood River	November, 2023	Public Engagement Forum	28	3
Pendleton	November, 2023	Public Engagement Forum	23	3
Roseburg	November, 2023	Public Engagement Forum	71	4
Bend	December, 2023	Public Engagement Forum	66	5
Total			**229**	**16**

Public forums included presentations from company representatives on strategic wildfire mitigation programs, system hardening and improvements, PSPS protocols, and customer engagement and preparedness. For those unable to attend in person, forums and booths were streamed live. All included Spanish and American Sign Language (ASL) interpretation. The community forums were promoted through paid advertising, local news coverage, and published to the Pacific Power website and social media channels with links for live stream access. Local elected officials, emergency managers, and other stakeholders were invited via email.

During these forums, communities were informed on key elements of the Pacific Power WMP. In-person and online (via a chat function) question and answer sessions were conducted to allow for community member engagement. The forums allowed for a two-way dialogue and created space for feedback to be collected and applied in context to key elements of the plan. Additionally, participants were provided with a means of submitting follow up questions via email. Informational brochures were also made available to community. Pacific Power's 2022 forum engagement experience had a total of 55 attendees, to improve engagement and attendance, successful experiences from other company events were implemented in 2023, to include meals at events and timings when people could attend during a typical workday break or after typical workday. Additionally, Public Safety Partners were engaged in the process to support attendance and promotion within their communities. Each forum event had at least one local emergency manager present, and many had other emergency service attendees.

Figure 78: 2023 WMP Forums

Table 32 provides a summary of the feedback and dialogue from each forum.

Table 32: Feedback from Forums and Booth Events

Community	Event Feedback
Cannon Beach	Pacific Power provided feedback and responses to 15 inquiries, with topics including situational awareness procedures, vegetation management programs, asset inspection programs and grid hardening efforts. Questions were predominantly related to vegetation management efforts and a Pacific Power forester on site was able to support customer feedback to questions.
Philomath	Pacific Power provided feedback and responses to five inquiries, with topics including situational awareness procedures, vegetation management programs, asset inspection programs and grid hardening efforts. Questions were predominantly related to vegetation management efforts and ancillary utility programs like Pacific Power's Blue Sky renewable energy program.
The Dalles	Pacific Power provided feedback and responses to 20 inquiries, with topics including situational awareness procedures and grid hardening efforts. Customers inquired about situational thresholds that could drive utility decision making, as well as general safety preparedness they can prepare. Pacific Power supplied several customers with brochures which included a preparedness checklist.
Hood River	Pacific Power provided feedback and responses to 10 inquiries, with topics including situational awareness procedures, grid hardening efforts and local field operations activities in their area. During the question-and-answer session, field operations were able to support questions related to specific work in the area. Additional questions focused on the cost of undergrounding versus other options and what kind of events can cause outages. This event was also promoted on a local Oregon news station.[33]
Pendleton	Pacific Power provided feedback and responses to eight inquiries, with topics including situational awareness procedures, vegetation management programs, asset inspection programs and grid hardening efforts. Several questions included discussion on what the company plans for undergrounding lines looks like and what kind of wind can drive utility decisions.

33 https://www.youtube.com/watch?v=hyRFLp6g1SE

Community	Event Feedback
Roseburg	Pacific Power provided feedback and responses to 15 inquiries, with topics including PSPS, medical baseline customers, outage response, and vegetation management practices. Questions were predominantly related to PSPS protocols and procedures, for which the Company Director of Emergency Management was available to answer.
Bend	Pacific Power provided feedback and responses to six inquiries, with topics including vegetation management, asset inspection programs, and grid hardening efforts. Questions from customers allowed discussions about why covered conductor versus undergrounding would be used, IR inspections versus visual inspection programs, and requesting and reporting debris and tree removal needs.

10.6. CAMPAIGN AND ENGAGEMENT EVALUATION

In 2023, consistent with OAR 860-300-0020 (1)(f), Pacific Power expanded the company's customer survey program from one, annual survey to bi-annual customer surveys throughout the service territory in April and October. The overall objective of this research was to measure the public's awareness of messaging related to wildfire preparedness and safety to inform development of the next year's engagement campaign. Because wildfire can occur anywhere, the survey's reach was not limited to customers who reside within the FHCA. Instead, all areas of the company's Oregon service territory were evaluated.

Specific research objectives of the 2023 surveys included:

- Measurement of customer awareness of Pacific Power messages related to wildfire preparedness.
- Customer recall of specific message topics.
- Customer recall of message channels.
- Measurements of customer recall and understanding about Public Safety Power Shutoff (PSPS).

- Identification of sources customers are most likely to turn to for information about PSPS.
- Evaluation of the PSPS experience.
- Exploration of actions taken by customers to prepare for wildfire season.
- Measurement of customer awareness of Pacific Power's efforts to reduce the risk of wildfires.
- Evaluation of PSPS notification perception.
- Measurements of customer recall and understanding about Pacific Power's Medical Certificate Program and associated PSPS mitigation programs.

The target audience for the survey included residential, business, and critical customers in Oregon and was conducted using a mix of online and phone surveys made available in English and Spanish. A grand total of 5,363 surveys were completed. Of those, 150 respondents identified as critical customers. A breakdown of survey responses for 2023 is shown in Table 33.

Table 33: Breakdown of Survey Responses

Survey Method	April 2023	September 2023	Total
Web	2,792	2,571	**5,363**
Phone	75	75	**150**
Total	**2,867**	**2,646**	**5,513**

High level findings from the 2023 customer and CBO surveys are described in detail below. They are grouped by general awareness and PSPS awareness.

GENERAL AWARENESS HIGHLIGHTS

TV News, email and social media were the primary channels recalled for general wildfire preparedness communications.

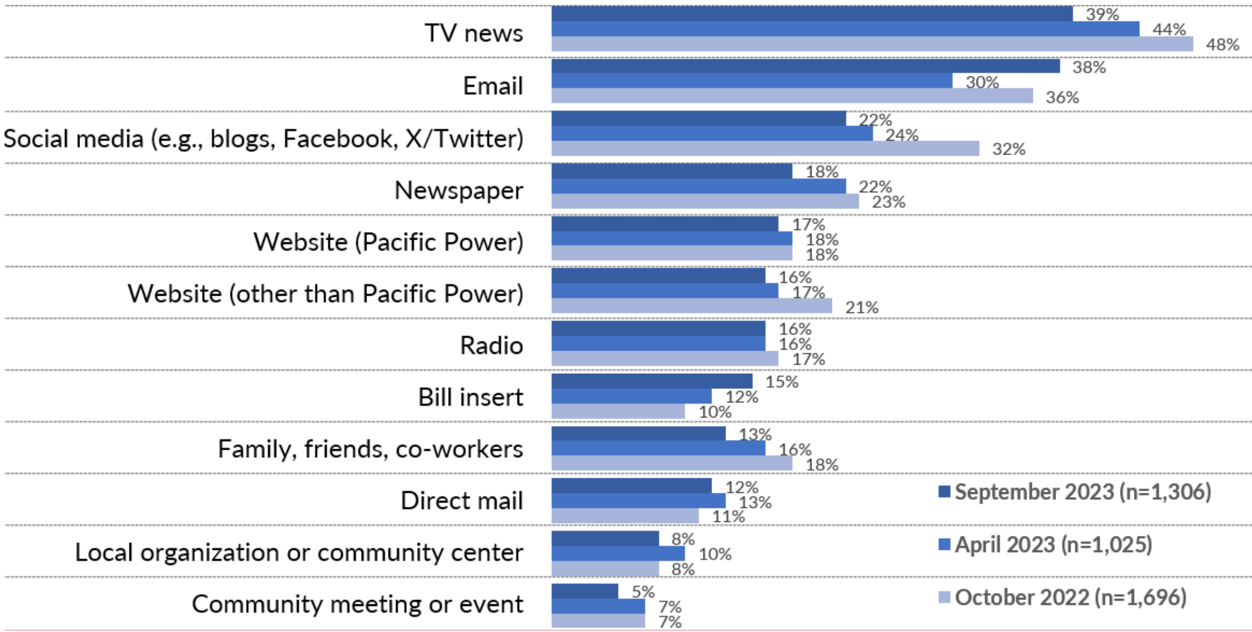


Figure 79: Information Channels for Wildfire Communications

Of the messages recalled, **Pacific Power's website was considered the most clear and useful source** for information about wildfire preparedness.

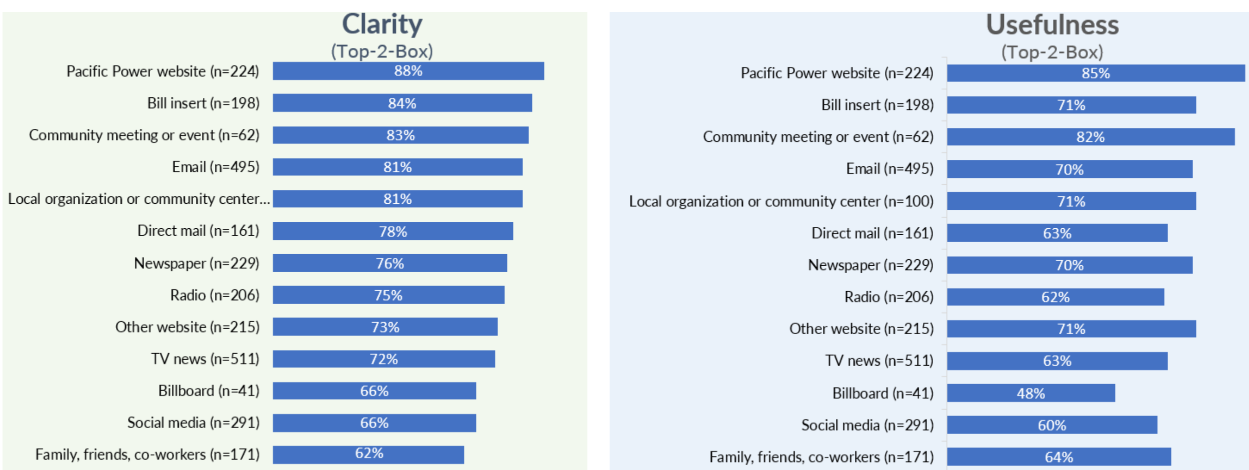


Figure 80: Information Usefulness and Clarity

Notifications via text message were considered the most effective communication method **from Pacific Power**, followed closely by email.

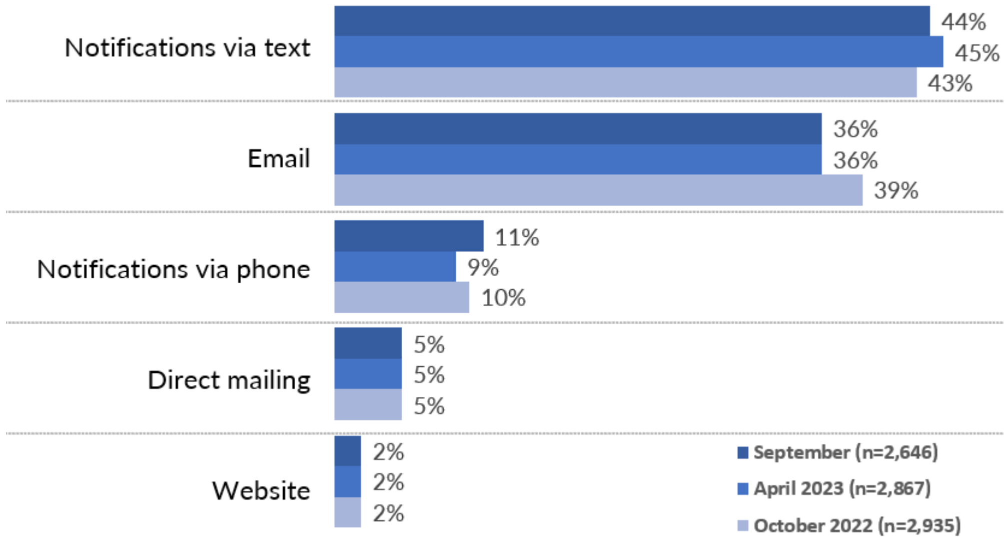


Figure 81: Most Effective Methods of Communication

Regarding content of messages recalled, **60% of respondents were aware of personal preparedness**.

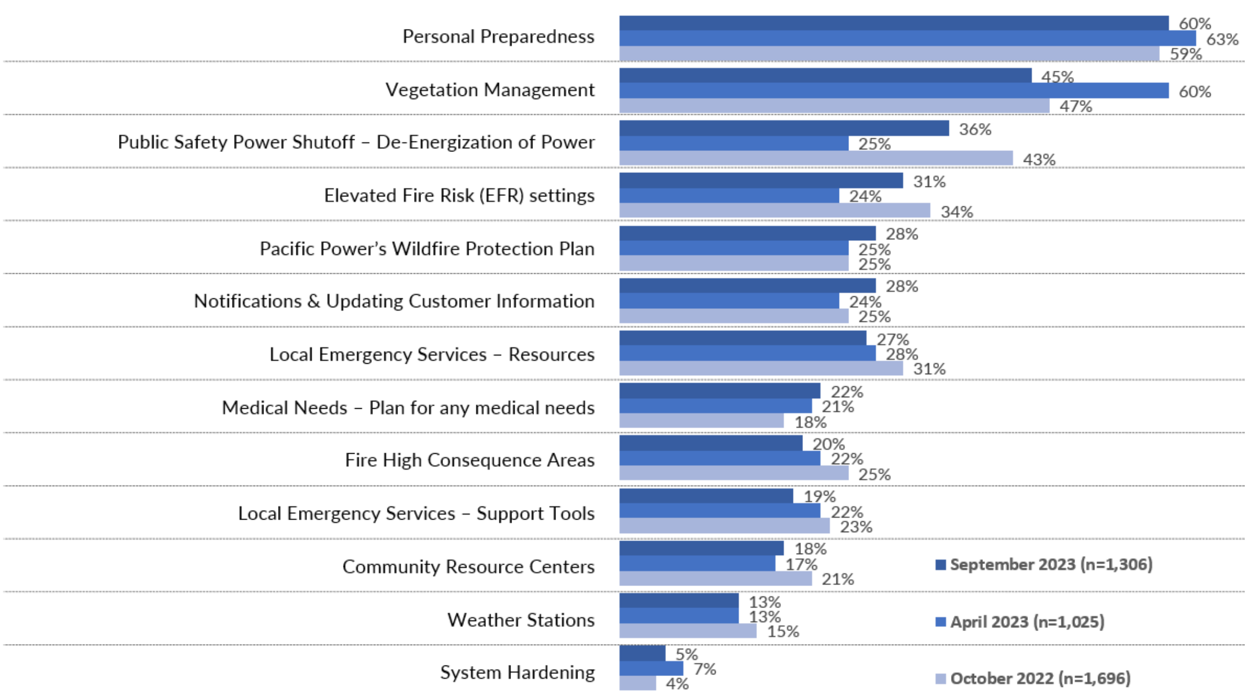


Figure 82: Message Recall

45% of respondents also reported taking action to prevent wildfires or to prepare their home or business for the event of a wildfire, as shown in Figure 83.

Actions Taken *(among those taking action)*	September 2023 Total (n=1,178)	Random (n=1,135)	Critical (n=43)
Trimmed vegetation around home or property	68%	68%	65%
Created defensible space	16%	16%	16%
Prepared an emergency kit	16%	**16%**	7%
Watering/installed watering systems	13%	13%	19%
Prepared an emergency readiness plan and contact information	10%	10%	7%

Figure 83: Actions Taken for Wildfire Preparedness

In terms of Pacific Power's efforts to reduce wildfire risk, respondents were **most aware (42%) of pruning vegetation** around power lines in higher-risk areas.

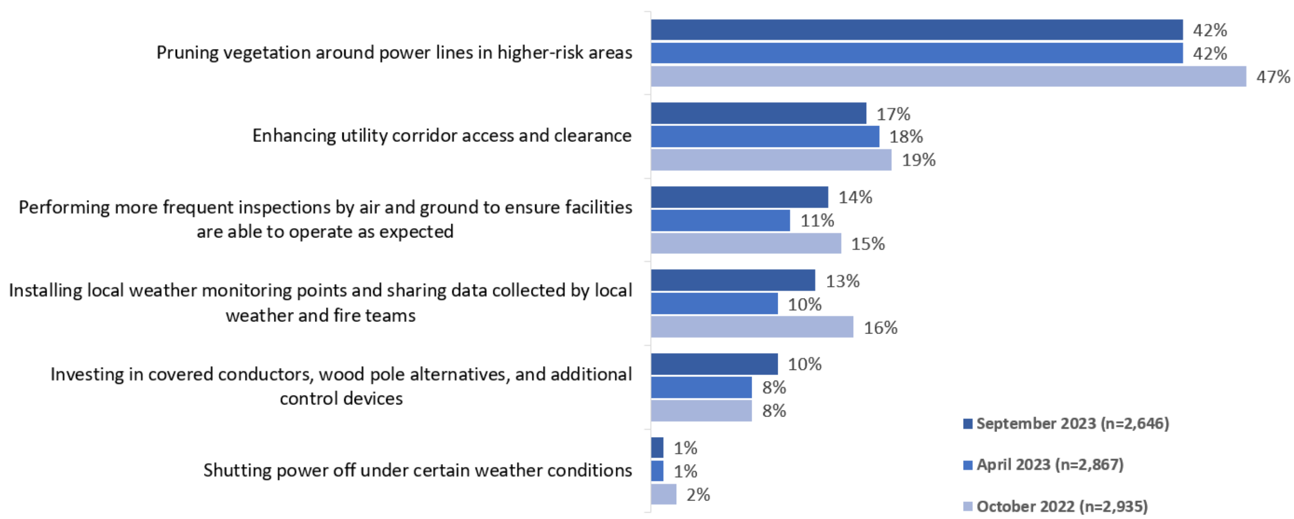


Figure 84: Awareness of Pacific Power's Effort to Reduce Wildfire Risk

PSPS MESSAGING HIGHLIGHTS

39% recalled seeing, hearing, or reading the phrase "Public Safety Power Shutoff or PSPS" primarily from TV news, social media, email, and radio.

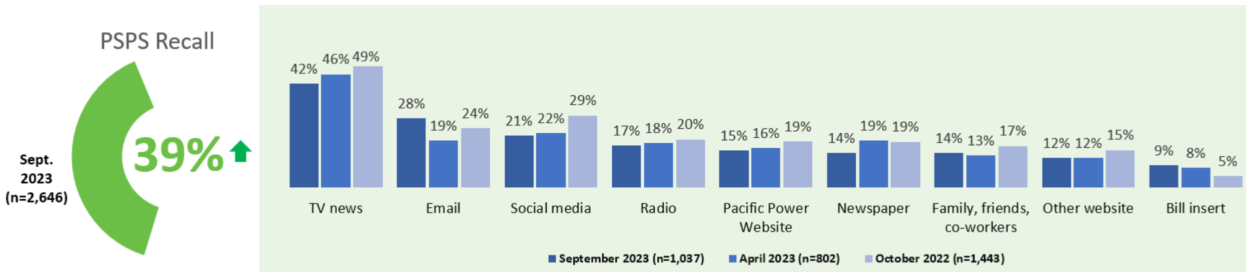


Figure 85: Sources of PSPS Communication

For 51% of customers, the Pacific Power website was the main source they turned to for information about PSPS.

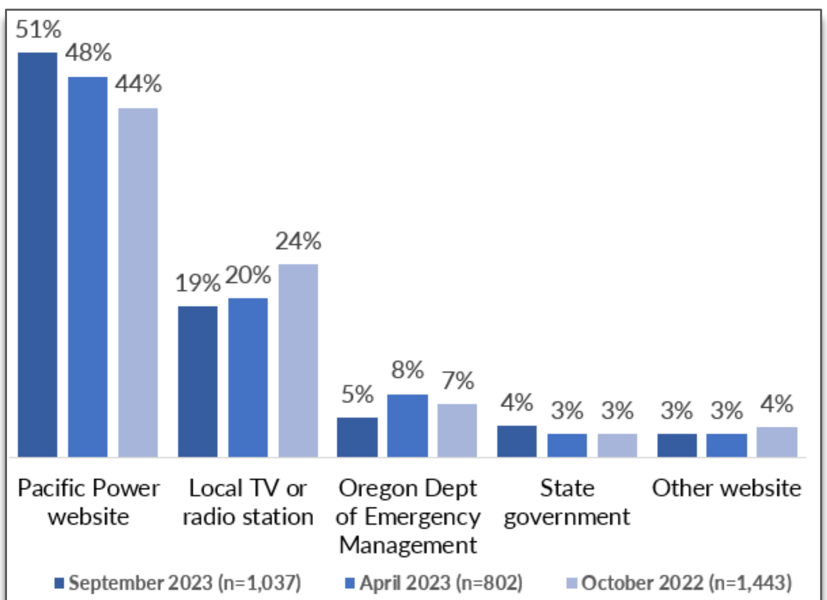


Figure 86: Top 5 Sources of PSPS Information

For 51% of customers, the Pacific Power website was the main source they turned to for information about PSPS. Of customers who reported an understanding of PSPS, **approximately 77%** reported understanding that "For areas at a higher risk of fast-spreading catastrophic wildfires, the utility will proactively shut off power during extreme and dangerous weather." A more detailed assessment of customer understanding of PSPS is shown in Table 34 below.

Table 34: Customer Understanding of PSPS

PSPS Understanding	Recall Rate
For areas at a higher risk of fast-spreading catastrophic wildfires, the utility will proactively shut off power during extreme and dangerous weather.	77%
Before considering a Public Safety Power Shutoff the utility assesses several factors: dry trees and other fuel, winds, extremely low humidity, weather conditions, population density, real-time on-the-ground observations and input from local public safety and health agencies.	58%
A Public Safety Power Shutoff is a last resort by the utility to prevent a fast-moving, hard to fight wildfire to help ensure customer and community safety.	51%
The likelihood of a Public Safety Power Shutoff is reduced when the utility takes steps to harden the electric grid.	33%
Taking steps to enhance situational awareness by tracking satellite information and monitoring weather conditions can reduce the likelihood of a Public Safety Power Shutoff.	28%

In September 2023, 35% of customers were aware they had the ability to update their contact information for PSPS. **However, 52% of customers surveyed in September 2023** reported that they had updated their contact information, a decrease from of 8% from the April 2023 survey.

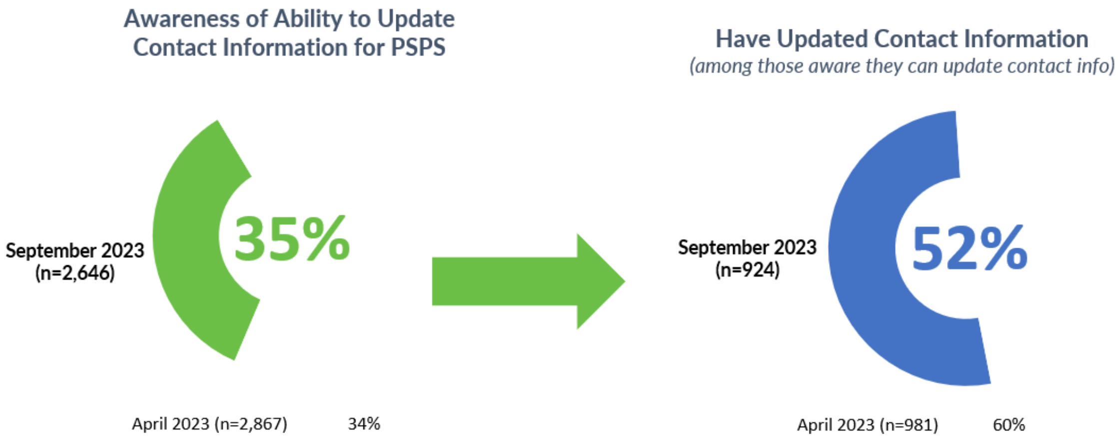


Figure 87: Customer Contact Information for PSPS

Based on the survey results, English is not a primary language for one in ten customers (12%) but is still preferred for communications for the vast majority (98%). Out of all respondents, 2% responded that it would be helpful for them or anybody else in their household to receive communication in another language. Additionally, when asked what their preferred language would be to receive communications from Pacific Power, Spanish (1% of all respondents), Tagalog (<1%), Traditional Chinese (<1%), Vietnamese (<1%), Zapoteco (<1%) are the only non-English languages mentioned.

Other highlights from the customer survey are summarized in Table 35 below.

Table 35: Customer Survey Highlights

Topic Area	Recall Rate October 2022	 April 2023	 October 2023
Aware of Wildfire Safety Communications	58%	36%	49%
Aware of Communications from Pacific Power (among those aware)	26%	22%	33%
Took Action to Prevent or Prepare for a Wildfire	49%	43%	44%
Recall PSPS	49%	28%	39%
Would Turn to Pacific Power Website for PSPS Info	44%	16%	52%
Aware of Ability to Update Contact Info for PSPS	39%	34%	34%
Satisfied with Availability of Resources in Community for Wildfire Safety Info	25%	22%	24%
Aware of Additional PSPS Notices for Those with Medical Need (among those with medical need)	12%	16%	18%

While many external factors such as wildfire activity in the community, prominent news articles, and local events can impact or bias utility survey results, these customer surveys provide Pacific Power with the best insight into customer recall to inform program direction.

For example, from 2022 to 2023, Pacific Power customers were more likely to turn to the Pacific Power website for PSPS information, which emphasizes its importance as a tool to provide all aspects of information from wildfire safety preparedness to PSPS details. Additionally, an increase in recall rates from April to October in 2023 was observed in most categories. While exact causation of this is unknown, this signals the potential impact of new articles as well as Pacific Powers 2023 wildfire safety ad campaign, described earlier in this section.

RECOMMENDATIONS

Based on the survey results, the third-party survey administrator suggested the following considerations for the 2024 Wildfire Safety and Preparedness customer engagement campaign:

- Awareness of wildfire safety messages and PSPS increased dramatically from April. Continue to promote wildfire Safety and PSPS preparation to maintain a baseline awareness in Oregon, comparable to what is seen in California.
- Increase dissemination of information to customers who rely on electricity for medical needs, including the ability to get a Medical or Life Support Equipment Certificate and eligibility for the Battery Rebate Program, and the requirement to renew annually. Awareness of increased notifications and other benefits designed for this group remains low.
- Consider end of season information about how customers can manage vegetation on their properties, such as tree trimming, to prepare for the next fire season. While vegetation management is one of the most common messages recalled, recall in October 2023 has decreased significantly from April of the same year, and back to levels seen in October 2022.

- Prioritize TV news, email, and social media to educate customers about wildfire safety and PSPS. While these channels remain the most common for awareness messaging, recall of TV news messaging continues to decline.
- Focus traditional media and social media communications on driving customers to the Pacific Power website, as well as leveraging bill inserts to communicate quick and valuable information, while also referring customers to the website for more detail. Sources directly from Pacific Power are considered highly clear and useful, while mass media and social media are less clear/useful.
- Focus communications on PSPS, how to be prepared and respond to an outage (including an emergency kit and readiness plan), and the steps Pacific Power is taking. Additionally, educate customers about the reasons for PSPS and how it keeps communities safe.
    - The percentage of customers aware of and taking action to create defensible space and manage vegetation remains high, but awareness and action for other steps lags. Similarly, awareness of Pacific Power's efforts to prune vegetation is high, but other steps taken have much lower awareness.
    - Awareness of PSPS is high in the Southern Oregon and Willamette Valley South regions but lags in other vulnerable areas of the state. Special attention should be paid to Central Oregon, Northeast Oregon, and Portland, which have lower than average awareness of PSPS.

10.7. 2023 WILDFIRE COMMUNICATIONS AND OUTREACH PLAN

The company's overall approach to wildfire communications and its outreach plan remains the same year over year, as shown in Figure 88. For example, the company always runs a paid advertising, customer email, and initiative-taking news media engagement campaign and it conducts a customer webinar.

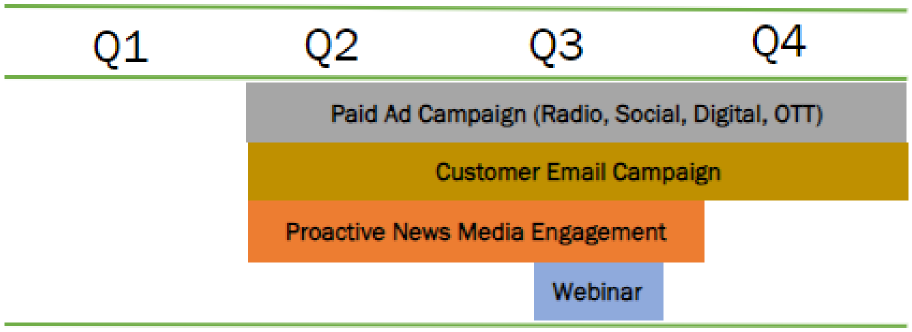


Figure 88: Wildfire Communications and Outreach Plan Timeline

Consistent with OAR 860-300-0020 (1)(f), program modifications are also made annually based on metrics that evaluate customers' level of engagement in messaging for the prior year's campaign, internal analysis, public safety partner input, and subject matter expertise. These inputs are summarized in Figure 89.

	Topic Area	Before Wildfire Season	During Wildfire Season	After Wildfire Season
Updated annually based on input from partners	Tabletop Exercise	x		
	Mailers	x	x	x
	Community Events – Oregon Get Ready			x
	Community Events - Other	x		x
	WMP Engagement Forums			x
Updated annually based on customer survey	Webinars	x		
	Awareness and Engagement Campaign	x	x	x

Figure 89: Communication and Outreach Summary

Modifications to the wildfire communications and outreach plan may also be made based on metrics that evaluate reach and customer engagement with messaging, as depicted in Appendix H – Engagement Campaign Performance.

10.8. BACKUP ELECTRIC POWER REBATE PROGRAM

In addition to the outreach and engagement strategy described in the sections above, Pacific Power has also introduced a new program to mitigate outage impacts to customers that rely on medical equipment powered by electricity. In 2023, the company implemented a new backup power rebate program that offers customers enrolled in Pacific Power's Medical Certificate program[34] a rebate on the purchase of a portable power station or battery. Pacific Power offers the rebate through direct outreach to customers that are actively enrolled in the company's Medical Certificate Program and on its backup electric power webpage.[35]

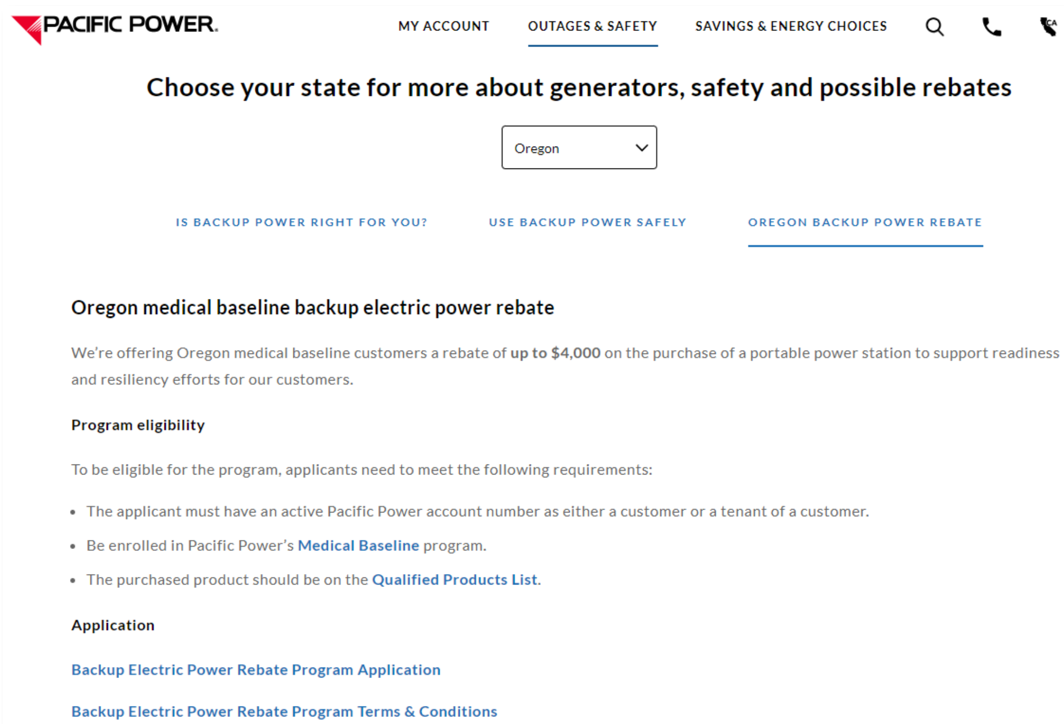


Figure 90: Backup Electric Power Rebate Webpage

[34] Medical Certificate (pacificpower.net)

[35] Backup electric power (pacificpower.net)

11. INDUSTRY COLLABORATION

Industry collaboration is another component of Pacific Power's WMP. Through active participation in workshops, international and national forums, consortiums, and advisory boards, Pacific Power maintains an understanding of existing best practices and collaborates with industry experts regarding emerging technologies and research.[36]

For example, Pacific Power is an active member of the International Wildfire Risk Mitigation Consortium (IWRMC),[37] an industry-sponsored collaborative designed to facilitate the sharing of wildfire risk mitigation insights and discovery of innovative and unique utility wildfire practices from across the globe. This consortium, with working groups focused in the areas of asset management, operations and protocols, risk management, and vegetation management, facilitates a system of working and networking channels between members of the global utility community to support the ongoing monthly sharing of data, information, technology, and practices. As a member, Pacific Power completed the IWRMC maturity model and analyzed the benchmarked data to inform program maturity. From the model, four categories were identified to focus on maturity. PacificCorp has verified ten initiatives are planned for maturity progression in the next three years. A summary of the categories and maturation progression are listed in Appendix E.

Pacific Power is participating in the three-year Electric Power Research Institute (EPRI) Climate Resilience and Adaptation Initiative (READi) to develop, in collaboration with industry stakeholders and other utilities, a common framework or guideline to assess climate risk, address resiliency and evaluate investments. This common framework includes aligning on a consistent approach to understand climate-related data, application, and climate trends, apply a common set of climate data to perform asset and system

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[36] A summary of 2023 industry collaborative forums is provided in Appendix E.

[37] See https://www.umsgroup.com/what-we-do/learning-consortia/iwrmc/.

vulnerability assessments, and to evaluate investments and grid hardening technologies across power systems.

Pacific Power is also coordinating with other investor-owned utilities in Orgon to develop a framework to evaluate the effectiveness of enhanced vegetation management programs in reducing wildfire risk, relative to cost. This joint IOU work may also align with work underway by Electric Power Research Institute (EPRI) to develop a national standard to model effectiveness of vegetation management. Pacific Power's current vegetation management process is described in Section 3.

As identified in Section 1.4, Pacific Power is continuing its participation in formal regulatory proceedings, workshops, and multi-state and multi-utility collaborations to progress collaboration from 2024-2027 in the areas of baseline risk mapping, risk spend efficiency calculations, and mitigation selection planning processes.

Having participated in expert forums, Pacific Power has utilized these solutions and used them to inform key parts of its WMP programs. Cited research, reports, and studies used to provide program benefits are shown in Appendix E – Collaboration and Industry Learnings.

Through these various engagement channels, Pacific Power aims to maintain industry networks, understand the evolution of technologies, discover broader applications for such advancements, freely share data to enable scientists and academics, collaborate with developers to push the boundaries of existing capabilities, and expand its research network through support of advisory boards or grant funding. Participation in these industry networks is continuing to increase Pacific Power's confidence in its WMP strategies and program elements.

12. PLAN MONITORING AND IMPLEMENTATION

In 2021 Pacific Power developed a new department, commonly referred to as wildfire safety. The new department as shown in Figure 91 below consists of multiple groups, including the program delivery team, responsible for overall plan development, implementation, and monitoring.

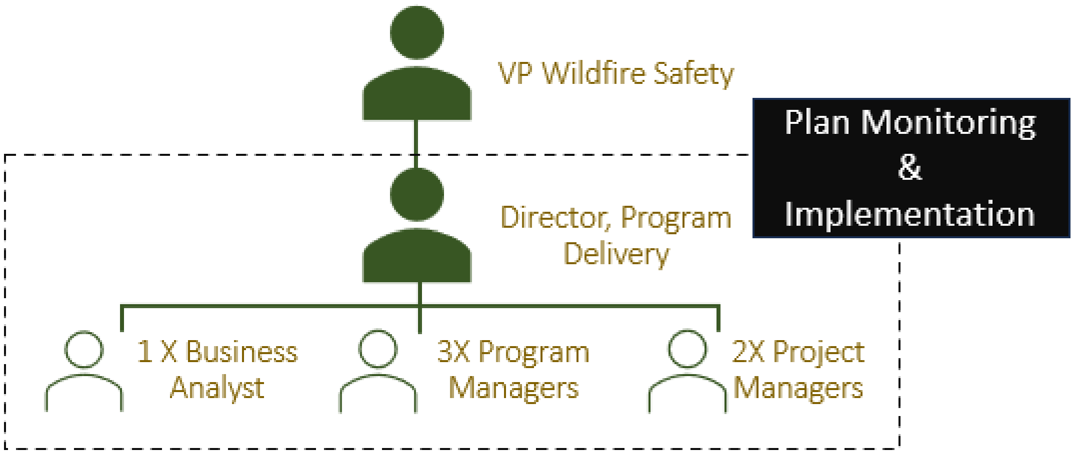

Figure 91: Pacific Power's Program Delivery Group

While the broader wildfire safety organization is tasked with supporting all types of wildfire mitigation initiatives and strategies across the company's entire service territory, the key function of wildfire safety program delivery team is to develop, implement, monitor, and improve the company's WMP in Oregon. It is the responsibility of wildfire safety program delivery to coordinate with other internal departments such as asset management, vegetation management, field operations, and emergency management to ensure all aspects of the plan are delivered. Additionally, wildfire safety program delivery regularly evaluates its plan and provides updates as needed and consistent with statutory and regulatory requirements.

The wildfire safety and asset management team, specifically the wildfire safety program delivery group, is responsible for developing the wildfire mitigation plan, incorporating enhancements to existing initiatives, and scoping new initiatives. Developing the plan requires internal collaboration across many different departments to establish the lessons learned applied with existing initiatives; for example, the streamlining of system hardening projects as described in Section 4. The group is also responsible for making sure the elements of the plan meet the regulatory requirements in accordance with OAR 860-300-

0020.To further evolve the company's wildfire mitigation capabilities, new initiatives are analyzed, scoped, and pursued; for example, the enhanced technologies used to evaluate risk as described in Section 1 and the increase in computational requirements mentioned in Section 5.

In addition to evaluating the plan elements, Pacific Power is also monitoring potential cost sharing and partnership opportunities to secure federal and state grant funding and offset the potential impacts to customers. Many of the company's wildfire mitigation programs, such as grid hardening, which includes investment in transformational technology, align with the goals and objectives of potential grant funding.

Implementation of the plan requires processes in place to ensure each initiative is progressing toward the established plan. Initiative owners are responsible for developing individual project plans to ensure the plan objectives are met. Wildfire safety program delivery ensures that the project plans are aligned with the WMP's objectives, and that key performance metrics are in place to monitor progress.

Once the plan is filed it is the wildfire safety team's responsibility to ensure the mitigations are being performed as described in the plan. Monitoring includes verification that initiative owners have plans to deliver projects on time and regular status checks to ensure work is progressing as planned. The regular status checks ensure that risks and issues are being appropriately monitored and prompt action is taken to resolve issues and remove barriers to successful project execution.

13. PLAN SUMMARY, COSTS, AND BENEFITS

13.1. 2023 PROGRAM ACHIEVEMENTS AND 2024 OBJECTIVES

Pacific Power WMP is designed to provide timely and cost-effective wildfire mitigation benefits through a range of programs. While described in more detail through the plan itself, Table 36 below summarizes the program elements, 2023 achievements, and 2024 program objectives.[38]

Table 36: Summary of 2023 Program Results and 2024 Objectives

Program Category	General Program Description	2023 Achievements	2024 Program Objectives
Risk Modeling & Drivers	Maintain baseline risk maps and framework to identify areas that are subject to a heightened risk of wildfire and inform longer term, multi-year investment and programs	✓ Refreshed FHCA Map ✓ Updated Fire Sight composite risk ✓ Improved advanced data analytics tools	➢ Continued FireSight model updates. ➢ Update composite risk. ➢ Continued development for advanced data analytics
Inspection & Correction	Continue FHCA inspection programs (5-yr detail, annual visual assurance), accelerated correction timeframes for fire threat conditions (6 months or less), and implementation of IR inspections on transmission	✓ 10,700 incremental detailed inspections ✓ 79,000 incremental visual assurance inspections ✓ 894 fire threat conditions corrected ✓ IR Inspection completed on 2,398 miles	➢ Continuation of FHCA Inspection Programs ➢ Continue expanded IR inspection program beyond the FHCA to include approximately 1,000 additional line miles in 2024 ➢ Pilot drone inspections

[38] 2023 achievements in this table are estimates or end of year forecasts based on document preparation ahead of the filing.

Program Category	General Program Description	2023 Achievements	2024 Program Objectives
Vegetation Management	Transition to a 3-yr trim cycle system wide, increase post trim clearances in the FHCA, implement annual pole clearing of subject poles in the FHCA, and perform annual inspections in the FHCA	✓ Inspected over 1,600 additional line-miles ✓ Removed and pruned over 10,000 additional trees (including brush equivalent) ✓ Radially cleared over 20,000 poles	➢ Continue implementation of 3-yr distribution cycle ➢ Continue FHCA Vegetation Management programs including expanded post work clearances
System Hardening	Long term investment to mitigate wildfire risk including line rebuilds, system protection and control equipment upgrades, and replacement of OH fuses and adjacent equipment	✓ 80 miles[39] constructed ✓ Initiated design of 125 miles ✓ 90 devices upgraded ✓ 10,776 fuses replaced	➢ Construct 125 miles of covered conductor ➢ Design 125 miles of covered conductor ➢ Upgrade 65 devices ➢ Replace ~8,000 fuses
Situational Awareness	Install and operate a company owned weather station network, implement a risk forecasting and impact-based fire weather model, and inform key decision making and protocols	✓ 47 weather stations installed. ✓ Implemented WFA-E ✓ Developed Hot-Dry-Windy Index ✓ Completed 30-yr WRF reanalysis	➢ Install 25 additional weather stations ➢ Install 5 wildfire detection cameras ➢ Improve weather forecasting ➢ Increase modeling capacity
System Operations	Risk-based implementation of EFR settings and re-energization practices in a manner that balances risk mitigation with potential impacts to customers	✓ Risk-based implementation of EFR settings and re-energization practices ✓ Evaluated 89 circuits with EFR outages for mitigation	➢ Continued risk-based implementation of EFR settings and re-energization practices ➢ Implement operational projects prior to 2024 fire season

[39] Pacific Power successfully constructed 65.5 miles of covered conductor through December 1, 2023, and, at the time of plan preparation, is forecasting completion of an additionally 14.5 miles by December 31, 2023.

Program Category	General Program Description	2023 Achievements	2024 Program Objectives
Field Operations & Work Practices	Acquire and maintain key equipment (water trucks, COWs, & personal suppression equipment) and implement risk-based work practices and resource adjustments	✓ Risk based work practices. ✓ Acquired equipment needed for wildfire activities. ✓ Purchase 2 COW	➢ Purchase 6 Starlink devices. ➢ Continued implementation of risk-based work practices ➢ Assess additional equipment needs
PSPS Program	Maintain the ability to actively monitor conditions, assess risk, and implement a PSPS as a measure of last resort in a manner that limits the impacts to customers and communities consistent with regulatory requirements	✓ Maintain readiness to implement PSPS.	➢ Maintain readiness to implement PSPS ➢ Expand general preparedness beyond the FHCA
Public Safety Partner Coordination	Develop and implement a public safety partner engagement strategy to enhance coordination and ensure preparedness	✓ Completed 2 tabletops ✓ Completed 7 workshops ✓ Completed PSPS portal development	➢ Complete 6 workshops ➢ Conduct 2 regional tabletop exercises
Wildfire Safety & Preparedness Engagement Strategy	Manage a multi-pronged approach to engage and inform the public and customers regarding wildfire safety & preparedness	✓ 12 million impressions ✓ Over 57,000 clicks ✓ 294 Customer calls about wildfire ✓ 3 booth events and 4 in-person public forums ✓ Webpage updates for Spanish translations ✓ 2,646 survey participants ✓ Initiate backup power rebate program	➢ Continue multi-pronged outreach campaign ➢ Continue to refine information for ease of use and access. ➢ Identify community engagement opportunities with external stakeholders ➢ Continued implementation of power rebate program
Industry Collaboration	Participate in consortiums, forums, and advisory boards to collaborate with industry experts, maintain expertise in	✓ Participated in the California joint IOU workstreams	➢ Collaborate with California joint IOU workstreams

Program Category	General Program Description	2023 Achievements	2024 Program Objectives
	leading edge technologies and operational practices, and continue to improve and advance the WMP and its programs	✓ Collaborated with Oregon joint IOUs ✓ Completed IWRMC Maturity Survey	➢ Progress Oregon joint IOU efforts ➢ Discover experiences from the IWRMC ➢ Grow IWRMC Maturity Survey usage
Plan Monitoring & Implementation	Leverage a centralized, dedicated team to develop, monitor, implement, and continuously improve the WMP	✓ Investigated grant funding opportunities ✓ Better QA/QC for program tracking	➢ Complete negotiation of invited grant funding opportunity ➢ Continue review of QA/QC processes for program tracking ➢ Develop mitigation selection process

13.2. COSTS

Delivering Pacific Power's multi-year WMP, as summarized above, requires an increase in investment across multiple years. In 2023, Pacific Power invested approximately $52.1 million in capital and $26.3 million of expense to accomplish the plan elements. In addition, Pacific Power is currently forecasted and additional investment of $975 million through 2028 (across five years), or $780 million capital and $195 million expense. Some programs, as understood today, require finite investment with a planned end date. Other programs, such as enhanced inspections or vegetation management, are expected to be on-going and annual in nature. Additionally, the line rebuild program, which is particularly large and complex in scope, is forecasted to continue beyond 2028 consistent with the company's advancement in risk modeling. Furthermore, not all programs require spend of each type in each year.

The following tables describe, consistent with staff recommendations in docket UM2207 (9), Pacific Power's actual 2023 spend and current five-year estimate[40] of these incremental costs broken down by program and expenditure type. The values provided for actuals in 2023 represent best estimates or end of year forecasts based on the timing of the document preparation and all values provided are subject to change. Additionally, the capital costs included reflect spend occurring each year, which may differ from values included in GRC filings or cost recovery mechanism applications which include costs based on when assets are placed in service. Furthermore, the costs reflect Oregon's allocation of associated programs and projects and, finally, while the tables only include a five-year forecast, these programs and increased expenditure are expected to continue beyond 2028. Milestones and quantities for the programs listed below can be viewed in Appendix F – Program Goals.

[40] Costs presented in Table 37 and 38 represent the most current estimates. These values could differ from GRC filings or previous testimonies.

Table 37: Planned and Actual Incremental Expense by Category ($millions)

Program Category	2023 Actuals	2024	2025	2026	2027	2028	5 Year Total
Risk Modeling and Drivers	**$0.59**	**$2.43**	**$2.16**	**$2.16**	**$2.17**	**$2.18**	**$11.10**
Baseline Risk Map	*$0.06*	*$0.53*	*$0.25*	*$0.25*	*$0.25*	*$0.25*	*$1.53*
Risk Assessment	*$0.43*	*$1.58*	*$1.59*	*$1.59*	*$1.60*	*$1.61*	*$7.97*
Advanced Data Analytics	*$0.10*	*$0.32*	*$0.32*	*$0.32*	*$0.32*	*$0.32*	*$1.60*
Asset Management	**$0.75**	**$1.22**	**$1.22**	**$1.22**	**$1.22**	**$1.22**	**$6.10**
Patrol Inspection	*$0.31*	*$0.47*	*$0.47*	*$0.47*	*$0.47*	*$0.47*	*$2.35*
Detail Inspection	*$0.21*	*$0.45*	*$0.45*	*$0.45*	*$0.45*	*$0.45*	*$2.25*
Infrared Inspection	*$0.23*	*$0.30*	*$0.30*	*$0.30*	*$0.30*	*$0.30*	*$1.50*
Drone Pilot	-	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
Vegetation Management	**$19.04**	**$25.26**	**$21.46**	**$21.46**	**$21.46**	**$21.46**	**$111.10**
Inspections and clearing	*$11.79*	*$16.95*	*$16.95*	*$16.95*	*$16.95*	*$16.95*	*$84.75*
Pole Clearing	*$3.23*	*$4.51*	*$4.51*	*$4.51*	*$4.51*	*$4.51*	*$22.55*
3yr Cycle Transition	*$4.02*	*$3.80*	-	-	-	-	*$3.80*
Grid Hardening	**$0.47**	**$1.71**	**$1.81**	**$1.83**	**$1.84**	**$1.86**	**$9.06**
Fault Indicators	*$0.13*	*$0.25*	*$0.35*	*$0.37*	*$0.38*	*$0.40*	*$1.75*
Fast Trip Fault Indicators	-	*$1.12*	*$1.12*	*$1.12*	*$1.12*	*$1.12*	*$5.60*
Facility Lease	*$0.34*	*$0.34*	*$0.34*	*$0.34*	*$0.34*	*$0.34*	*$1.71*
Situational Awareness	**$1.76**	**$2.12**	**$2.36**	**$2.44**	**$2.50**	**$2.53**	**$11.95**
Meteorology Department	*$0.14*	*$0.14*	*$0.14*	*$0.14*	*$0.14*	*$0.14*	*$0.70*
Weather Forecasting	*$1.26*	*$1.35*	*$1.49*	*$1.50*	*$1.51*	*$1.52*	*$7.37*
Weather Stations	*$0.36*	*$0.58*	*$0.68*	*$0.75*	*$0.80*	*$0.82*	*$3.63*
Detection Cameras	*$0.00*	*$0.05*	*$0.05*	*$0.05*	*$0.05*	*$0.05*	*$0.25*
Field Ops. & Practices	**$1.81**	**$3.10**	**$3.10**	**$3.10**	**$3.10**	**$3.10**	**$15.50**
PSPS Watch Patrols	*$1.80*	*$2.56*	*$2.56*	*$2.56*	*$2.56*	*$2.56*	*$12.80*
EFR Outage Patrols	-	*$0.50*	*$0.50*	*$0.50*	*$0.50*	*$0.50*	*$2.40*
Preparedness Equipment	*$0.02*	*$0.02*	*$0.02*	*$0.02*	*$0.02*	*$0.02*	*$0.10*
Communication Devices	*$0.02*	*$0.04*	*$0.04*	*$0.04*	*$0.04*	*$0.04*	*$0.20*
PSPS Program	**$0.02**	**$3.00**	**$3.00**	**$3.00**	**$3.00**	**$3.00**	**$15.00**
PSPS Event	-	*$2.20*	*$2.20*	*$2.20*	*$2.20*	*$2.20*	*$11.00*
Battery Rebate Program	*$0.02*	*$0.80*	*$0.80*	*$0.80*	*$0.80*	*$0.80*	*$4.00*
Public Partner Coord.	**$0.20**	**$0.17**	**$0.17**	**$0.17**	**$0.17**	**$0.17**	**$0.85**
Tabletop Exercises	*$0.00*	*$0.03*	*$0.03*	*$0.03*	*$0.03*	*$0.03*	*$0.15*
Emergency Mgmt. Team	*$0.20*	*$0.14*	*$0.14*	*$0.14*	*$0.14*	*$0.14*	*$0.70*
Engagement Strategy	**$0.82**	**$1.98**	**$2.07**	**$2.16**	**$2.25**	**$2.36**	**$10.82**
Comms. Campaign	*$0.75*	*$1.38*	*$1.47*	*$1.56*	*$1.65*	*$1.76*	*$7.82*
Public Forums	*$0.07*	*$0.60*	*$0.60*	*$0.60*	*$0.60*	*$0.60*	*$3.00*
Industry Collaboration	**$0.07**	**$0.07**	**$0.07**	**$0.02**	**$0.02**	**$0.02**	**$0.20**
EPRI Climate READi	*$0.05*	*$0.05*	*$0.05*	-	-	-	*$0.10*
IWRMC Membership	*$0.02*	*$0.02*	*$0.02*	*$0.02*	*$0.02*	*$0.02*	*$0.10*
Plan Monitoring	**$0.77**	**$0.88**	**$0.61**	**$0.61**	**$0.61**	**$0.61**	**$3.32**
Program Delivery	*$0.57*	*$0.61*	*$0.61*	*$0.61*	*$0.61*	*$0.61*	*$3.05*
Grant Opportunities	*$0.20*	*$0.27*	-	-	-	-	*$0.27*
Grand Total	**$26.30**	**$41.94**	**$38.03**	**$38.17**	**$38.34**	**$38.51**	**$195.00**

Table 38: Planned and Actual Incremental Capital Investment by Category ($millions)

Program Category	2023 Actuals	2024	2025	2026	2027	2028	5 Year Total
Risk Modeling and Drivers	**$1.15**	**$1.97**	**$2.07**	**$2.14**	**$2.14**	**$2.14**	**$10.46**
System Hardening	**$45.99**	**$161.29**	**$151.88**	**$149.25**	**$151.65**	**$151.65**	**$765.72**
Line Rebuild	*$22.44*	*$113.75*	*$113.75*	*$113.75*	*$113.75*	*$113.75*	*$568.75*
System Automation	*$11.46*	*$19.25*	*$17.75*	*$16.50*	*$16.50*	*$16.50*	*$86.50*
Fuse Replacement	*$5.73*	*$17.94*	*$11.08*	*$10.00*	*$10.00*	*$10.00*	*$59.02*
Fault Indicators	*$0.92*	*$0.08*	*TBD*	*TBD*	*TBD*	*TBD*	*$0.08*
Early Fault Detection	-	*$0.17*	*TBD*	*TBD*	*TBD*	*TBD*	*$0.17*
System Allocated	*$5.44*	*$10.10*	*$9.30*	*$9.00*	*$11.40*	*$11.40*	*$51.20*
Situational Awareness	**$1.39**	**$2.71**	**$0.80**	**$0.52**	**$0.34**	**$0.16**	**$4.53**
Weather Stations	*$1.08*	*$0.63*	*$0.43*	*$0.20*	*$0.13*	*$0.13*	*$1.52*
Weather Forecasting	*$0.31*	*$1.23*	*$0.37*	*$0.32*	*$0.21*	*$0.03*	*$2.16*
Wildfire Detection	-	*$0.85*	*TBD*	*TBD*	*TBD*	*TBD*	*$0.85*
Field Ops. & Practices	**$3.60**	**$0.08**	-	-	-	-	**$0.08**
Grand Total	**$52.13**	**$166.05**	**$154.75**	**$151.91**	**$154.13**	**$153.95**	**$780.79**

Pacific Power anticipates continuously improving its WMP in a way that aligns with community and Commission expectations. Key takeaways from collaborations with other utilities, Public Safety Partners, the Commission, communities, and customers will be evaluated for incorporation into future WMPs and may require corresponding changes or updates to these forecasts.

Through partnerships, there are opportunities to secure general and state grant funding which have the potential to progress wildfire mitigation objectives and offset potential impacts to the customer. Beginning in 2022, Pacific Power began applying for, and actively pursuing grant funding opportunity where in 2023, Pacific Power was invited to negotiations by the GRIP grant program. Should the GRIP grant be awarded as proposed, it would support funding of several programs in this plan.

13.3. CO-BENEFITS OF PLAN

Pacific Power's WMP encompasses various strategies, programs, and investments designed to reduce the risk of wildfire, in a manner consistent with emerging industry best practices. The elements of this plan provide clear benefits in the areas of wildfire mitigation, whether through enhanced inspections and corrections, additional vegetation management activities, or system hardening and the implementation of covered conductor. Additionally, maturation in the areas of risk mapping and situational awareness facilitate the prioritization and balancing of efforts to ensure the plan is delivered as efficiently as practical.

In identifying plan elements, Pacific Power considered both the costs and the benefits of any approach. Its strategies were guided by the principle that the frequency of ignition events related to electric facilities can be reduced by engineering more resilient systems that experience fewer fault events.

While the mitigation strategies in this plan are designed to reduce the risk of wildfire, many also offer co-benefits to the utility operation and its customers. The joint IOUs have worked on a common structure for assessing benefits, yet the way the benefits are assessed can vary from utility to utility. While there are nuances, Table 39 identifies which program categories could provide perceived co-benefits.

Table 39: Co-benefit Objectives

Projects	Utility Definition	Distribution System Planning	Safety	Reliability	Resiliency
Vegetation Management	Incremental wildfire mitigation programs within the FHCA such as annual cycle work.		√	√	
Asset Inspections and Corrections	Incremental wildfire mitigation programs within the FHCA such as increased inspection frequency and accelerated corrections		√	√	
Grid Hardening	Incremental WMP programs such as recloser / relay installations, and line rebuilds (covered conductor, undergrounding, etc.)	√	√	√	√
Situational Awareness	Incremental WMP programs such as weather station installations.	√	√	√	√
Research and Development					
Advanced Forecasting (Weather)			√	√	√

More frequent asset inspections can result in the identification and accelerated correction of additional conditions, which reduces wildfire risk. This same program can also improve public safety, worker safety, and reliability. Similarly, system hardening provides one of the most beneficial ways to reduce wildfire risk, by increasing the level of localized weather conditions that can be tolerated without impact on the utility operations. For example, installing covered conductor will increase the grid's resiliency against wind-driven contacts. The mechanical properties of a covered conductor design physically prevent the initiation of a flash-over due to contact, mitigating wildfire risk. For this same reason, covered conductor also reduces the potential for outages, thereby providing significant reliability benefits.

Furthermore, Pacific Power's situational awareness capabilities provide multiple wildfire mitigation benefits by informing operational and field protocols and playing a key role in the facilitation of PSPS protocols and decision-making. Along the same lines, situational awareness, paired with operational readiness, provides co-benefits throughout the year by supporting Pacific Power's response to many types of emergency related events, such as winter storms. While the program is designed to mitigate wildfire risk, Pacific Power anticipates leveraging this new capability to support other types of emergency response and overall system resilience.

Finally, Pacific Power's WMP includes the use of emerging technologies, such as the implementation of advanced protection and control schemes. While key to reducing the potential for utility related spark events following a fault event, this equipment provides additional co-benefits in the areas of distribution system planning readiness. These projects lay the initial foundation for greater incorporation of other tactics, such as distribution automation or distributed generation.

APPENDIX A – ADHERENCE TO REQUIREMENTS

OAR 860-300-0020 – WILDFIRE MITIGATION PLAN FILING REQUIREMENTS

Consistent with OAR 860-300-0020 effective September 8, 2022, per Order No. 22-335:

(1) Wildfire Mitigation Plans and Updates must, at a minimum, contain the following requirements as set forth in Oregon Revised Statutes (ORS) 757.963 (2)(a)-(h) and as supplemented below:

Plan Requirement	Corresponding Plan Section / Reference
(a) Identified areas that are subject to a heightened risk of wildfire, including determinations for such conclusions, and are: (A) Within the service territory of the Public Utility, and (B) Outside the service territory of the Public Utility but within the Public Utility's right-of-way for generation and transmission assets.	• Section 1.2, Fire High Consequence Area (FHCA), for a description of how Pacific Power developed updated baseline wildfire risk with considerations of topography, fuel data, climatology, historic fire data, and various other inputs to the risk modeling to develop the new FHCA map.
(b) Identified means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk.	• Section 1.3 Risk Treatment - Program Selection and Prioritization, for a description on how Pacific Power selects projects based on risk utilizing the baseline risk map and other tools. • Section 1.3, under Phase 3– Project Evaluation and Selection, to understand how Pacific Power plans to incorporate advanced data analytics tools into decision making, and • Section 13 for total planned cost and a discussion on program benefits.

Plan Requirement	Corresponding Plan Section / Reference
(c) Identified preventative actions and programs that the Public Utility will carry out to minimize the risk of utility facilities causing wildfire.	• Section 2, Inspection and Correction, for a description of the inspection programs performed to identify conditions that require corrections, • Section 3, Vegetation Management, for the vegetation inspection and clearing work being performed around the transmission and distribution assets and rights of way, • Section 4, System Hardening, for the proactive hardening which includes line rebuild, undergrounding, and system automation to reduce the potential risk, • Section 5,Situational Awareness, for the weather modeling that informs the increases awareness across the PacifiCorp territory and operational decision-making, • Section 6, System Operations, for the enabling of Elevated Fire Risk settings contributed to the daily risk assessment described in the situational awareness section, • Section 7, Field Operations and Work Practices, to see how the field may adjust their work practices depending on the local conditions along with the tools provided to aid field work to reduce potential risk, • Section 8, Public Safety Power Shutoff, for the criteria, communications, outreach, and preparedness required prior and in a PSPS event. • Additional supporting programs include risk assessment, public safety partner coordination, industry collaboration, and external engagement.
(d) Discussion of outreach efforts to regional, state, and local entities, including municipalities regarding a protocol for the de-energization of power lines and adjusting power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure.	• Section 9, Public Safety Partner Coordination Strategy, which outlines the general strategy and planned exercises and workshops to facilitate public and private sector coordination, validate communications protocols, and verify capability to support communities during extreme risk events. • See Section 0, Wildfire Safety & Preparedness Engagement Strategy, for a description of how the

Plan Requirement		Corresponding Plan Section / Reference
		company is engaging customers and the general public throughout its three-state service area on the topic of wildfire safety and preparedness through a variety of tactics including webinars, in-person forums, targeted paid media campaigns, press engagement.
(e)	Identified protocol for the de-energization of power lines and adjusting of power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure, including a PSPS communication strategy consistent with OAR 860-300-0040 through 860-300-0050.	• Section 6, System Operations, for a description of how Pacific Power is adjusting power system operation through the implementation of Elevated Fire Risk (EFR) settings. • See Section 7, Field Operations & Work Practices, which includes how field operations managers deploy additional resources and perform additional patrols or augment work practices such as the deferral of any nonessential work at locations with dense and dry wildland vegetation, especially during periods of heightened fire weather conditions. • See Section 8, Public Safety Power Shutoff (PSPS) Program, for a description of the company's PSPS protocols
(f)	Identification of the community outreach and public awareness efforts that the Public Utility will use before, during and after a wildfire season, consistent with OAR 860-300-0040 and 860-300-0050.	• See Section 9, Public Safety Partner Coordination Strategy, for a description of Pacific Power facilitates annual discussion based and functional tabletop exercises to develop awareness of PSPS planning and procedures. • See Section 0, Wildfire Safety & Preparedness Engagement Strategy, for a description of for the description of webinars, in-person forums, targeted paid media campaigns, press engagement, distributed print materials, social media updates, and communication through owned channels.
(g)	Description of procedures, standards, and time frames that the Public Utility will use to inspect utility infrastructure in areas the Public Utility identified as heightened risk of wildfire, consistent with OAR 860-024-0018.	• Section 2, Inspection and Correction, for a description of when an inspection is performed on a Pacific Power asset, inspectors use a predetermined list of condition codes (defined below) and priority levels (defined below) to describe any noteworthy observations

Plan Requirement		Corresponding Plan Section / Reference
(h)	Description of the procedures, standards, and time frames that the Public Utility will use to carry out vegetation management in areas the Public Utility identified as heightened risk of wildfire, consistent with OAR 860-024-0016.	• Section 3, Vegetation Management, for a description of Power's existing vegetation management program is to minimize contact between vegetation and power lines by addressing grow-in and fall-in risks.
(i)	Identification of the development, implementation, and administrative costs for the plan, which includes discussion of risk-based cost and benefit analysis, including consideration of technologies that offer co-benefits to the utility's system.	• Section 13, Plan Costs, Summary, & Benefits for detailed costs and the list of program achievements and future goals.
(j)	Description of participation in national and international forums, including workshops identified in section 2, chapter 592, Oregon Laws 2021, as well as research and analysis the Public Utility has undertaken to maintain expertise in leading edge technologies and operational practices, as well as how such technologies and operational practices have been used to develop and implement cost effective wildfire mitigation solutions.	• Section 0, Industry Collaboration, for a description of Pacific Power's membership in the International Wildfire Risk Mitigation Consortium (IWRMC),[14] an industry-sponsored collaborative designed to facilitate the sharing of wildfire risk mitigation insights.
(k)	Description of ignition inspection program, as described in Division 24 of these rules, including how the utility will determine and instruct its inspectors to determine, condition that could pose an ignition risk on its own equipment and on pole attachments.	• Section 2.2, FHCA Inspection and Correction Programs, for a description of Pacific Power's FHCA inspection programs including a description of how fire threat conditions are determined, which reflects conditions that pose an ignition risk.

OAR 860-300-0030 – Risk Analysis

Risk Analysis Requirement	Corresponding Plan Section / Reference
(1) The Public Utility must include in its Wildfire Mitigation Plan risk analysis that describes wildfire risk within the Public Utility's service territory and outside the service territory of the public Utility but within the Public Utility's right of way for generation and transmission assets. The risk analysis must include, at a minimum:	• Section 1, Baseline Risk Analysis, for a description on how Pacific Power performs risk modeling and has developed the baseline wildfire risk within the service territory.
• Defined categories of overall wildfire risk and an adequate discussion of how the Public Utility categorized wildfire risk. Categories of risk must include, at a minimum:	
A. Baseline wildfire risk, which includes elements of wildfire risk that are expected to remain fixed for multiple years. Examples include topography, vegetation, utility equipment in place, and climate;	For a description on how the baseline risk map was developed and the inputs that went into determining the risk, refer to: • Section 1.2, Fire High Consequence Area (FHCA), for a description of how Pacific Power developed updated baseline wildfire risk with considerations of topography, fuel data, climatology, historic fire data, and various other inputs to the risk modeling to develop the new FHCA map. •
B. Seasonal wildfire risk, which include elements of wildfire risk that are expected to remain fixed for multiple months but may be dynamic throughout the year or from year to year; Examples include cumulative precipitation, seasonal weather conditions, current drought status, and fuel moisture content;	For a detailed description of how Pacific Power forecasts weather on or near its assets, see: • Section 5, Situational Awareness, provides a description of the weather modeling performed from real time and historical data using tools like FireCast and FireSim.
C. Risks to residential areas served by the Public Utility; and	Refer to: • Section 1.2, Fire High Consequence Area (FHCA) • Section 5, Situational Awareness, • Appendix C – Wildfire Risk Modeling Data Inputs.

Risk Analysis Requirement	Corresponding Plan Section / Reference
D. Risks to substation or powerline owned by the public Utility	Refer to: • Section 1.2, Fire High Consequence Area (FHCA) • Section 5, Situational Awareness, • Appendix C – Wildfire Risk Modeling Data Inputs.
• A narrative description of how the public Utility determined areas of heightened risk of wildfire using the most updated data it has available from reputable sources.	Refer to: • Section 1.2, Fire High Consequence Area (FHCA) • Section 5, Situational Awareness.
• A narrative description of all data sources the Public Utility uses to model topographical and meteorological components of its wildfire risk as well as any wildfire risk related to the Public Utility's equipment. A. The Public Utility must make clear the frequency with which each source of data is updated; and B. The Public Utility must make clear how it plans to deep its data sources as up to date as is practicable.	For a more dynamic view of the risk modeling and sources used, refer to: • Section 1.2, Fire High Consequence Area (FHCA) and Section 1.4 Continuous Improvement, for the data and frequency used in relation to the different risk modeling activities performed. • Section 5, Situational Awareness • Appendix C – Wildfire Risk Modeling Data Inputs.
• The Public Utility's risk analysis must include a narrative description of how the Public Utility's wildfire risk models are used to make decisions concerning:	
A. Public Safety Power Shutoffs	To develop an understanding of how all the components work together to inform the risk and when a PSPS should be taken, refer to: • Section 5.5 (Situational Awareness), Application and Use, • Section 6, System Operations, • Section 7, Field Operations & Work Practices, and • Section 8, Public Safety Power Shutoff (PSPS) Program
B. Vegetation Management	For a description of the risk areas and the vegetation management work being performed in the FHCA see: • Section 1.2, Fire High Consequence Area (FHCA), and • Section 3, Vegetation Management.

Risk Analysis Requirement	Corresponding Plan Section / Reference
C. System Hardening	For a description on how the system hardening initiatives are informed by the risk modeling work performed, please reference: • Section 1.2, Fire High Consequence Area (FHCA) • Section 1.3, Risk Treatment - Program Selection and Prioritization, and • Section 4, System Hardening.
D. Investment decisions; and	For a description on how projects are identified based on the risk modeling and then prioritized, refer to: • Section 1.3, Risk Treatment - Program Selection and Prioritization.
E. Operational decisions.	For a description of how the risk assessment can affect operational decisions, see: • Section 5.5 (Situational Awareness), Application and Use, • Section 6, System Operations, and • Section 7, Field Operations and Work Practices.
• For updated Wildfire Mitigation Plans, the Public Utility must include a narrative description of any changes to its baseline wildfire risk that were made relative to the previous plan submitted by the utility, including the Public Utility's response to changes in baseline wildfire risk, seasonal wildfire risk, and Near-term Wildfire Risk.	For baseline risk updates, see: • Section 1.2, Fire High Consequence Area (FHCA), and • Appendix C – Wildfire Risk Modeling Data Inputs. For dynamic risk, refer to: • Section 5, Situational Awareness and • Appendix C – Wildfire Risk Modeling Data Inputs.
(2) To the extent practicable, the Public Utility must confer with other state agencies when evaluating the risk analysis included in the Public Utility's Wildfire Mitigation Plan.	To understand how Pacific Power is collaborating on programs and associated risks, refer to: • Section 9, • Public Safety Partner Coordination Strategy, • Section 0, Wildfire Safety and Preparedness Engagement Strategy, and • Section 0, • • Industry Collaboration.

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OAR 860-300-0040 – WILDFIRE MITIGATION PLAN ENGAGEMENT STRATEGIES

	Engagement Strategy Requirement	Corresponding Plan Section / Reference
(1)	The Public Utility must include in its Wildfire Mitigation Plan a Wildfire Mitigation Plan Engagement Strategy. The Wildfire Mitigation Plan Engagement Strategy will describe the utility's efforts to engage and collaborate with Public Safety Partners and Local Communities impacted by the Wildfire Mitigation Plan in the preparation of the Wildfire Mitigation Plan and identification of related investments and activities. The Engagement Strategy must include, at a minimum:	To understand how Pacific Power is engaging with the community, customers, and regulators, see: • Section 0, Wildfire Safety and Preparedness Engagement Strategy.
(a)	Accessible forums for engagement and collaboration with Public Safety Partners, Local Communities, and customers in advance of filing the Wildfire Mitigation Plan. The public Utility should provide, at minimum:	For a description of the forums and other collaboration activities performed refer to: • Section 0, Public Safety Partner Coordination Strategy and • Section 0, Wildfire Safety and Preparedness Engagement Strategy.
	A. One public information and input session hosted in each county or group of adjacent counties within reasonable geographic proximity and streamed virtually with access and functional needs considerations; and	For a description of the Pacific Power hosted webinars and community forums, refer to: • Section 0, Wildfire Safety and Preparedness Engagement Strategy.
	B. One opportunity for engagement strategy participants to submit follow-up comments to the public information and input session.	For a description of the Pacific Power hosted webinars and community forums, please see: • Section 10.5, Webinars and Community Forums
(b)	A description of how the Public Utility designed the Wildfire Mitigation Plan Engagement Strategy to be inclusive and accessible, including considerations for multiple languages and outreach to access and functional needs populations as identified with local Public Safety Partners.	For information regarding accessibility and availability of information in languages other than English, please see: • Section 10.3, Customer Service Training and 10.4, Wildfire Safety, Preparedness, and PSPS Webpages.

Engagement Strategy Requirement	Corresponding Plan Section / Reference
(2) The Public Utility must include a plan for conducting community outreach and public awareness efforts in its Wildfire Mitigation Plan. It must be developed in coordination with Public Safety Partners and informed by local needs and best practices to educate and inform communities inclusively about wildfire risk and preparation activities.	For a description of the community outreach and public awareness efforts performed, refer to: • Section 10.7, 2023 Wildfire Communications and Outreach Plan and • Section 0, Public Safety Partner Coordination Strategy.
(a) The community outreach and public awareness efforts will include plans to disseminate informational materials and/or conduct trainings that cover:	
A. A description of PSPS including why one would need to be executed, considerations determining why one is required, and what to expect before, during, and after a PSPS;	See Section 0 - Wildfire Safety and Preparedness Engagement Strategy and Section 0 - Public Safety Partner Coordination Strategy for the criteria requiring a PSPS event and how that information would be communicated, refer to: • Section 0, Wildfire Safety and Preparedness Engagement Strategy and • Section 0, Public Safety Partner Coordination Strategy.
B. A description of the Public Utility's wildfire mitigation strategy;	For outreach and information on wildfire safety, refer to: • Section 0, Wildfire Safety and Preparedness Engagement Strategy.
C. Information on emergency kits/plans/checklists;	For the preparedness information and checklists available to customers, see: • Section 10.4, Wildfire Safety, Preparedness, and PSPS Webpages.
D. Public Utility contact and website information.	For a description of utility outreach that includes details on where company contact information can be found and accessed, see: • Section 0, Wildfire Safety and Preparedness Engagement Strategy and

Engagement Strategy Requirement	Corresponding Plan Section / Reference
	• Section 0 Public Safety Partner Coordination Strategy.
(b) In formulating community outreach and public awareness efforts, the Wildfire Mitigation Plan will also include descriptions of:	
A. Media platforms and other communication tools that will be used to disseminate information to the public;	For a description of the types of communication methods utilized to inform and reach out to the public, please reference: • Section 0, Wildfire Safety and Preparedness Engagement Strategy.
B. Frequency of outreach to inform the public;	Details on the frequency of communications to the public can be found in: • Section 0, Wildfire Safety and Preparedness Engagement Strategy.
C. Equity considerations in publication and accessibility, including, but not limited to: (i) Multiple languages (ii) Multiple media platforms to ensure access to all members of a local community.	Details on the publication and accessibility of information, including language availability and platform type are described at length in: • Section 0, Wildfire Safety and Preparedness Engagement Strategy.
(3) The Public Utility must include in its Wildfire Mitigation Plan a description of metrics used to track and report on whether its community outreach and public awareness efforts are effectively and equitably reaching Local Communities across the Public Utility's service area.	For information on the TV News, email, and social media campaigns that were performed, please refer to: • Section 10.6, Campaign and Engagement Evaluation.

Engagement Strategy Requirement	Corresponding Plan Section / Reference
(4) The Public Utility must include a Public Safety Partner Coordination Strategy in its Wildfire Mitigation Plan. The Coordination Strategy will describe how the public Utility will coordinate with Public Safety Partners before, during, and after the fire season and should be additive to minimum requirements specific in relevant Public Safety Power Shut Off requirements described in OAR 860-300-0050. The Coordination Strategy should include, at a minimum:	
(a) Meeting frequency and location determined in collaboration with Public Safety Partners;	For information on the frequency and method by which Pacific Power collaborates with public safety partners, refer to: • Section 0. Public Safety Partner Coordination Strategy.
(b) Tabletop Exercise plan that includes topics and opportunities to participate;	Pacific Power's tabletop exercise plan is described in: • Section 0. Public Safety Partner Coordination Strategy.
(c) After action reporting plan for lessons learned in alignment with Public Safety partner after action reporting timeline and processes.	For a list of the events Pacific Power emergency management held and feedback received from public safety partners, refer to: • Appendix G, Public Safety Partner Event Registry.

OAR 860-300-0050 – COMMUNICATION REQUIREMENTS PRIOR, DURING, AND AFTER A PUBLIC SAFETY POWER SHUTOFF (PSPS)

	PSPS Communication Requirement	Corresponding Plan Section / Reference
(1)	When a Public Utility determines that a PSPS is likely to occur, it must deliver notification of the PSPS to its Public Safety Partners, operators of utility-identified critical facilities, and adjacent local Public Safety Partners.	For a description of how Pacific Power will provide notification of a potential PSPS event, refer to: • Section 8.5 (Public Safety Partner Coordination Strategy), Communication Protocol.
(a)	To the extent practicable, the Public Utility must provide priority notification directly to the Public Safety Partners, operators of utility-identified critical facilities, and adjacent local Public Safety Partners.	See response to (1)
(b)	In notifying Public Safety Partners and utility identified critical facilities of PSPS events, including adjacent local Public Safety Partners, the utility will communicate the following information, at a minimum:	See response to (1)
	A. The PSPS zone, which would include Geographic Information System shapefile(s) depicting current boundaries of the area subject to a de-energization;	See response to (b)
	B. Date and time PSPS will be executed;	See response to (b)
	C. Estimated duration of PSPS;	See response to (b)
	D. Number of customers impacted by the PSPS;	See response to (b)
	E. When feasible, the Public Utility will support Local Emergency Management efforts to send out emergency alerts;	See response to (b)
	F. At a minimum, status updates at 24-hour intervals until service has been restored;	See response to (b)
	G. Notice of when re-energization efforts will begin and when re-energization is expected to be complete; and	See response to (b)

PSPS Communication Requirement	Corresponding Plan Section / Reference
H. Information provided under this rule does not preclude the Public Utility from providing additional information about execution of the PSPS to its Public Safety Partners.	See response to (b)
(c) In notifying utility-designated critical facilities, the Public Utility will communicate the following information, at a minimum:	See response to (b)
A. Data and time PSPS will be executed;	See response to (b)
B. Estimated duration of PSPS;	See response to (b)
C. At a minimum, status updates at 24-hour intervals util service has been restored;	See response to (b)
D. Notice of when re-energization efforts will begin and when re-energization is expected to be complete; and	See response to (b)
E. In addition to the above requirements, utilities will also provide Geographic Information Files with as much specificity as possible to Operators of Communications facilities in the area of the anticipated PSPS.	See response to (b)
(d) ESF-12 will notify Oregon Emergency Response System (OERS) partners and Local Emergency Management in coordination with Oregon's Office of Emergency Management.	See response to (b)
(2) When a Public Utility determines that a PSPS is likely to occur, the Public Utility must provide advance notice of the PSPS to customers via a PSPS web-based interface on the Public Utility's website and other media platforms and may communicate PSPS information directly with customers consistent with this rule.	A description of how a PSPS will be determined and the information that is updated and communicated can be found in: • Section 8.5 (Public Safety Partner Coordination Strategy), Communication Protocol. • Section 9.7 (Public Safety Partner Coordination Strategy), Public Safety Partner Portal, and • Section 0 (Wildfire Safety & Preparedness Engagement Strategy), Wildfire Safety, Preparedness, and PSPS Webpages.

PSPS Communication Requirement	Corresponding Plan Section / Reference
(a) In providing notice to customers about a PSPS, the Public Utility will, at a minimum:	See response to (2)
Utilize multiple media platforms to maximize customer outreach, including but not limited to, social media, radio, television, and press releases;	
A. Consider the geographic and cultural demographics of affected areas, including but not limited to broadband access, languages prevalent within the utility's service territories, considerations for those who are vision or hearing impaired; and	See response to (a)
B. Display on its website homepage a prominent link to access current information about the PSPS, consistent with OAR 860-300-0060, including a depiction of the boundary. The PSPS information must be easily readable and accessible from mobile devices.	See response to (a)
(b) The Public Utility may directly notify its customers through email communication or telephonic notification (e.g., text messaging and phone calls) when it will not impede Local Emergency Management alerts due to capacity limitations. If the Public Utility provides direct notification, the Public Utility will communication the following information, at a minimum:	For detailed information and methods in which the information will be communicated to customers in the event of a Public Safety Power Shutoff, please refer to: • Section 8.5 (Public Safety Partner Coordination Strategy), Communication Protocol.
A. A statement of impending PSPS execution, including an explanation of what a PSPS is and the risks that the PSPS would be mitigating;	See response to (b)
B. Date and time PSPS will be executed;	See response to (b)
C. Estimated duration of PSPS;	See response to (b)
D. A 24-hour means of contact customers may use to ask questions or seek information;	See response to (b)

PSPS Communication Requirement		Corresponding Plan Section / Reference
	E. How to access details about the PSPS via the Public Utility's website, including education and outreach materials disseminated in advance of the annual wildfire season;	See response to (b)
	F. After initial notification, the Public Utility will provide, at a minimum, status updates at 24-hour intervals until the conditions prompting the PSP have ended; and	See response to (b)
	G. Notice of when re-energization efforts will begin and when re-energization is expected to be complete.	See response to (b)
(3)	To the extent possible, the Public Utility will adhere to the following minimum notification prioritization and timeline in advance of a PSPS;	For a description on the timeline for notifications, see: • Section 8.5 (Public Safety Partner Coordination Strategy), Communication Protocol.
(a)	48-72 hours in advance of anticipated de-energization, priority notification to Public Safety Partners, operators of utility-identified critical facilities, and adjacent local Public Safety Partners;	See response to (3)
(b)	24-48 hours in advance of anticipated de-energization, when safe: secondary notification to all other affected customers; and	See response to (3)
(c)	1-4 hours in advance of anticipated de-energization, if possible: notification to all affected customers.	See response to (3)
(4)	The Public Utility's communications required under this rule do not replace emergency alerts initiated by local emergency response.	Information on how Pacific Power works with public safety partners including law enforcement and fire agencies can be found in: • Section 8.5 (Public Safety Partner Coordination Strategy), Communication Protocol.
(5)	Nothing in this rule prohibits the Public Utility from providing additional information about the execution of the PSPS to Public Safety Partners, utility-identified critical facilities, or customers.	For a description on the information that will be shared to public safety partners, critical facilities, and customers, please reference: • Section 8.5 (Public Safety Partner Coordination Strategy), Communication Protocol.

OAR 860-300-0060 – ONGOING INFORMATIONAL REQUIREMENTS FOR PUBLIC SAFETY POWER SHUTOFFS (PSPS)

PSPS Informational Requirement	Corresponding Plan Section / Reference
(1) The Public Utility will create a web-based interface that includes real-time, dynamic information non location, de-energization duration estimates, and re-energization estimates. The web-based interface will be hosted on the Public Utility's website and must be accessible during a SPSP event. The Public Utility will complete the web-based interface before March 31, 2024.	For an overview of the web-based Public Safety Partner Portal that will be available to public safety partners beginning in 2024, see: • Section 9.8, Public Safety Partner Portal.
(2) The Public Utility will make its considerations when evaluating the likelihood of a PSPS publicly available on its website. These considerations include, but are not limited to strong wind events, other current weather conditions, primary triggers in high-risk zones that could cause a fire, and any other elements that define an extreme fire hazard evaluated by the Public Utility.	For details on the information Pacific Power shares with customers regarding its evaluation of the likelihood of PSPS, refer to: • Section 10.4, Wildfire Safety, Preparedness, and PSPS Webpages.
(3) The Public Utility will ensure that its website has the bandwidth capable of handling web traffic surges in the event of a Public Safety Power Shutoff.	The bandwidth capacity of the Public Safety Power Shutoff webpage is described in: • Section 10.4, Wildfire Safety, Preparedness, and PSPS Webpages.
(4) The Public Utility will work to provide real-time geographic information pertaining to PSPS outages compatible with Public Safety Partner GIS platforms.	See response to (1)

OAR 860-300-0070 – REPORTING REQUIREMENTS FOR PUBLIC SAFETY POWER SHUTOFFS (PSPS)

	PSPS Reporting Requirement	Corresponding Plan Section / Reference
(1)	The Public Utility is required to file annual reports on de-energization lessons learned, providing a narrative description of all PSPS events which occurred during the fire season. Reports must be filed not later than December 31st of each year.	See Pacific Power's Annual PSPS Report, filed with the Oregon PUC as *Investor-Owned Utilities Public Safety Power Shut Off (PSPS) Reports*[41] and referenced in Section 8.8 (Public Safety Power Shutoff Program), Experience.
(2)	Non-confidential versions of the reports required under this section must also be made available on the Public Utility's website.	See Pacific Power's Annual PSPS Report also referenced in Section 8 Public Safety Power Shutoff (PSPS) Program, Experience.

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APPENDIX B – 2023 STAFF RECOMMENDATIONS

On June 6, 2023, Pacific Power received Docket No. 2207. It provided 29 recommendations for collaboration with Staff and stakeholders to be incorporated into the 2024 WMP. The joint Investor-Owned Utilities (IOUs) of Idaho Power, Portland General Electric and Pacific Power held 13 meetings together and five workshops with Staff in response to the recommendations. The collaborative effort will continue as the joint IOU's continue to evolve, develop, and respond to the recommendations. Meeting minutes from the previous staff workshop were documented and approved at the beginning of each staff meeting for alignment on understanding.

Consistent with Order No. 22-131 effective April 28, 2022, Pacific Power considered the following recommendations from Staff in the development of the 2024 WMP:

Staff Recommendation	Consideration
(1) Provide information on how Public Safety Partners in areas whose seasonal outlook could result in a PSPS are notified and communicated with throughout the risk period.	Please see Section 5.5, Pacific Power meteorology is developing, based on the already utilized System Impacts Forecast Matrix, to communicate to its public safety partners on a set cadence.
(2) Provide explicit details of assets within and outside the FHCA, as well as those areas within and outside areas that are at risk of PSPS, based on the seasonal outlooks.	As the Seasonal Fire Risk map is generated in 2024, an update on assets within and outside the FHCA shall be provided. Currently, Pacific Power has provided asset breakouts for FHCA and Non-FHCA, as described in Section 2.2, FHCA Inspection and Correction Programs.
(3) Detail any steps taken toward calibration of wildfire risk modeling methods to ensure that when and where overlaps occur, they are consistent, or explicably inconsistent, in their risk designation. Such designation and coordination across utilities may lend greater clarity for stakeholders and Staff to understand relative risks.	As discussed in Section 1.2 Fire High Consequence Area (FHCA), Pacific Power has identified seven utilities whose service territory is within two miles of the new FHCA and will communicate their risk modeling methods. Additionally, as discussed in Industry Collaboration, Pacific Power is also discussing ways to share risk model information to understand the similarities and differences with PGE and Idaho Power.

Staff Recommendation	Consideration
(4) Provide details for incorporation of climate change modeling in establishing the FHCA.	As discussed in Consideration of Climate Change in Wildfire Risk Modeling, the FireSight model accounts for climate change in the fuels moisture model that is an input to the Composite Risk Score. Pacific Power will also participate in California Office of Energy Infrastructure Safety (OEIS) workshops on integrating climate change into projections of wildfire risk to learn more about how other IOUs are integrating climate change into their wildfire risk models and guidance experts are providing regarding impacts of climate change on wildfire risk. Pacific Power will use learnings from the OEIS workshops as an input to evaluating if there are additional risk variables that are impacted by climate change and the feasibility of integrating them into wildfire risk modeling.
(5) Provide historic root cause analysis supporting equipment ignition risk determinations.	As discussed in Section 1.4, Continuous Improvement, Pacific Power has two projects to support tracking of ignition risk. The first project, Advanced Data Analytics Tool, will implement the functionality to track the fire incident data that is critical to validating modeled ignition risk and fire spread, update assumptions, and refine calculations. The second project, Fire Incident Root Cause Evaluation will evaluate the recommendations in OPUC Order 23-220[42] and assess the processes regarding investigation of ignition incidents. At that time Pacific Power will consider if any processes updates are required and how process changes may affect inspection program

[42] Oregon Public Utility Commission. "Order AR 23-220: In the Matter of PacifiCorp, dba Pacific Power, 2023 Wildfire Protection Plans". Entered June 26, 2023.

Staff Recommendation	Consideration
(6) Demonstrate the Company's ignition tracking database and processes and detail its enhancement roadmap and the role this information takes within its data analytics software and risk mitigation effectiveness estimations.	As discussed above in Advanced Data Analytics Tool, Pacific Power is implementing the functionality to track the fire incident data that is critical to validating modeled ignition risk and fire spread, update assumptions, and refine calculations. This information will be used to conduct long-term trend analysis of wildfire incidents near utility equipment to validate risk model assumptions and assess changes to risk drivers over time for inclusion in FireSight and PSPS risk modeling and mitigation planning.
(7) Provide program or project-level valuation for mitigations identified in the Company's WMP.	Pacific Power is planning to implement Risk Spend Efficiency to evaluate the effectiveness of proposed mitigations. The general approach is described above in Risk Spend Efficiency and the project to implement processes to review and update the model is discussed in Risk Spend Efficiency (RSE) Model Refresh.
(8) Detail progress made towards a uniform risk-spend valuation methodology.	Pacific Power is planning to implement Risk Spend Efficiency to evaluate the effectiveness of proposed mitigations. As discussed in Industry Collaboration, Pacific Power is coordinating with Idaho Power and PGE to develop meeting cadence, agendas, and opportunities for alignment on risk spend valuation methodology per the direction of the OPUC in docket UM 2207, recommendation.
(9) Provide planned and actual work completed and dollars planned and actually spent by program for the prior and future years, as well as associated estimations of risk reduction for the work completed, compared to their original estimations.	In 2023, Pacific Power invested approximately $52.6 million in capital and $25.7 million of expense to accomplish the plan elements. In addition, Pacific Power is currently forecasted and additional investment of $955 million through 2028 (across five years), or $780 million capital and $175 million expense. Please see Plan Summary, Costs, and Benefits for more information on the costs. Pacific Power is planning to implement Risk Spend Efficiency to evaluate the effectiveness of proposed

Staff Recommendation	Consideration
	mitigations. The general approach is described above in Risk Spend Efficiency. When this is implemented, the estimated and actual risk reduction can be provided for projects.
(10) Provide a multiyear plan with project-level details for any near-term capital investments, with objective priorities identified and the estimated wildfire risk reduction for the project's selected mitigation method.	Pacific Power's multi-year plan that outlined investments based on program categories was included in Section 13 of the 2023 WMP. After considering staff's recommendation, modifications were made to this multi-year plan as reflected in the following section. Please see Section 13.2— Plan Costs, Pacific Power is planning to implement Risk Spend Efficiency to evaluate the effectiveness of proposed mitigations. The general approach is described above in Risk Spend Efficiency. When this is implemented, the estimated and actual risk reduction can be provided for projects. The 2023 cost table did not include planned goals but has now been included in Appendix F – Program Goals.
(11) Identify areas of the service territory that may be affected by a PSPS or modified power system operations, and should this be system-wide, develop a method for producing and communicating these seasonal outlooks to inform Public Safety Partners of the elevated risk of PSPS.	As discussed in Seasonal Forecast, Pacific Power meteorology is developing a seasonal fire risk map that the company can communicate to its public safety partners on a set cadence.
(12) Evaluate additional CRC siting based upon the seasonal outlook and input from the relevant Public Safety Partners for those areas not historically considered at risk of PSPS.	Pacific Power as described in Section 8.6, works with its public safety partners to activate a temporary CRC as needed in locations not pre-identified.

Staff Recommendation	Consideration
(13) Include as an appendix to its WMP a registry of Public Safety Partner events, identifying hosting organization, with feedback provided and actions taken because of the feedback.	Appendix G – Public Safety Partner Event Registry Template details the growing list of public safety partner events.
(14) Provide information about the evolution of PSPS processes as lessons are learned.	Pacific Power's 2022 PSPS experience is described in Section 8.8, which provides a description of the experiences, recommended action, and the status of those experiences from 2022. Pacific Power considered Staff's recommendation and built upon last year's summary where it is detailed in Table 27.
(15) Provide findings of analyses regarding operational modifications based upon "fire season" or other relevant elevated wildfire periods.	In Section 6.1 of the 2023 WMP (Elevated Fire Risk Settings), the process for informing when devices would be enabled with Elevated Fire Risk (EFR) Settings and the impact of their implementation was addressed. The information analyzed included the outages attributed to devices that EFR settings enabled, and the impact implementation of the settings had on the company's System Average Interruption Duration Index (SAIDI) score.
(16) Provide updated language for Public Safety Partners and communities regarding modified operational practices, including "sensitive settings," PSPS, and other utility operational modes to mitigate wildfire risk.	Pacific Power has developed several wildfire safety and preparedness collateral pieces, as described in Section 10.2, Support Collateral. Additionally, other information is communicated on the company's website, as described in Section 10.4, Wildfire Safety, Preparedness, and PSPS Webpages.
(17) Coordinate community outreach with partners, including ESF-12, and consider broadening the workshop to include relevant community safety topics, inviting Public Safety Partners regarding other topics appropriate to the community.	As discussed in Section 10.5, Pacific Power broadened its public engagement and worked with public safety partners to support attendance and promotion of events within communities. In 2023, seven in-person and live streamed events provided an open environment for questions and public engagement.

Staff Recommendation	Consideration
(18) Detail methods for determining the effectiveness of customer outreach, distinguishing whether related to customers within or outside the HFCA, and describe any modifications made to outreach strategies as a result.	As discussed above in Section 10.6, Campaign and Engagement Evaluation, Pacific Power conducted bi-annual customer surveys throughout its service territory. Suggested recommendations based on the survey results have been included in this WMP. Additionally, other details, including the matrix presented to staff, can be found in Appendix H – Engagement Campaign Performance.
(19) Provide cost analysis relating frequency of incremental inspections and correction timeframes using the described data analytics tools it is developing.	As discussed in Section 1.4 under Advanced Data Analytics Tool, the functionality is being developed and Pacific Power is seeking to align with the other Investor-Owned Utilities (IOUs) on risk assessments that could potentially inform inspection programs. However, these will be applied to system hardening initiatives first. As part of its industry collaboration efforts (as described in Section 0), Pacific Power will also coordinate with the other IOUs for alignment. This is also discussed in Section 2.2, under FHCA Inspection and Correction Reasoning.
(20) Demonstrate the use of its ignition tracking database and process to support its approach to ignition prevention inspections.	As discussed in Section 1.4 under Advanced Data Analytics Tool, Pacific Power is implementing the functionality to track fire incident data critical to validating modeled ignition risk and fire spread, updating assumptions, and refining calculations. As part of its industry collaboration efforts (as described in Section 0), Pacific Power will coordinate with Idaho Power and PGE to determine the feasibility of a common framework to evaluate the effectiveness of inspection programs in reducing wildfire risk, relative to cost.
(21) Staff recommends Pacific Power utilize the previously recommended risk spend efficiency methodology to determine the risk reduction that enhanced vegetation management delivers to customers.	As discussed above, Pacific Power is implementing Risk Spend Efficiency, as described in Section 1.3, to select capital wildfire mitigations. As part of its industry collaboration work (described in Section 0), Pacific Power will coordinate with Idaho Power and PGE to determine the feasibility of a common framework to evaluate the effectiveness of enhanced vegetation

Staff Recommendation	Consideration
	management programs in wildfire risk reduction relative to cost. This joint IOU work may also align with work currently underway by Electric Power Research Institute (EPRI) to develop a national standard to model effectiveness of vegetation management.
(22) Staff recommends that root cause analysis for vegetation-related risks be conducted to support the determination of how vegetation management is employed, including any analysis of historic events relating to power lines, specific equipment type, vegetation, and wildfires.	As discussed in Section 1.4 under Advanced Data Analytics Tool, Pacific Power is implementing the functionality to track fire incident data critical to validating modeled ignition risk and fire spread, updating assumptions, and refining calculations. As part of its industry collaboration efforts (as described in Section 11), Pacific Power will coordinate with Idaho Power and PGE to determine the feasibility of a common framework to evaluate the effectiveness of inspection programs in reducing wildfire risk, relative to cost. This joint IOU work may also align with work currently underway by Electric Power Research Institute (EPRI) to develop a national standard to model effectiveness of vegetation management.
(23) Staff recommends that Pacific Power demonstrate its use of its ignition tracking database and process to evaluate the logic of its programmatic decisions for vegetation management in FHCAs and outside FHCAs.	As discussed in Section 1.4 under Advanced Data Analytics Tool, Pacific Power is implementing the functionality to track fire incident data critical to validating modeled ignition risk and fire spread, updating assumptions, and refining calculations. As part of its industry collaboration efforts (as described in Section 11), Pacific Power will coordinate with Idaho Power and PGE to determine the feasibility of a common framework to evaluate the effectiveness of inspection programs in reducing wildfire risk, relative to cost. This joint IOU work may also align with work currently underway by Electric Power Research Institute (EPRI) to develop a national standard to model effectiveness of vegetation management.

Staff Recommendation	Consideration
(24) Include a summary of the quantitative analysis used in the choice and prioritization of specific solutions and investments.	Pacific Power's current process for selecting and prioritizing specific mitigations is described in Section 1.3, under Program Selection and Prioritization. As Risk Spend Efficiency is implemented, the company will initiate a project, Annual Mitigation Selection Planning Process, to update its approach to the selection and evaluation of programs and projects to ensure that quantitative and qualitative assessments are well-integrated.
(25) Outline how solutions providing co-benefits have been considered in its investment strategies.	As discussed in Section 13.3, while the mitigation strategies in this plan are designed to reduce the risk of wildfire, many also offer co-benefits to the utility operation and its customers. The joint IOUs have also worked on a common structure for assessing benefits; nonetheless, the way the benefits are assessed can vary from utility to utility. While there are nuances, Section 13.3 identifies which program categories could provide perceived co-benefits. As risk spend efficiency (described in Section 1.3) is implemented, Pacific Power will initiate a project, Annual Mitigation Selection Planning Process, to update the process it uses to evaluate and select programs and projects to ensure that quantitative and qualitative assessments are well-integrated. This work will also evaluate whether co-benefits should be integrated into mitigation assessment.
(26) Discuss the impact of participation in expert forums on identification of solutions most likely to provide the benefits anticipated. This should include: a. Cited research, reports, and studies used in any analysis, unless the source is confidential. b. How the factors unique to the Company's facilities and service territory were used	As discussed in Section 0 (Industry Collaboration), Pacific Power is an active member of multiple forums so that it can enhance its understanding of existing best practices, emerging research, and technologies. In consideration of Staff's recommendation, Appendix E Cited Research and Informed Uses, discusses these participation efforts.

Staff Recommendation	Consideration
when considering the applicability of specific options to its systems.	
(27) In Recommendation 26, Staff recognized certain of the industry learnings were likely related to risk valuation, however directly responsive to the broader research and development and industry participation, Staff recommends Pacific Power provide specifics on program changes made in response to learnings from industry forums, as well as greater detail of who from the company participates and in what roles they function in various industry forums.	As discussed in Section 0 (Industry Collaboration), Pacific Power is an active member of multiple forums so that it can enhance its understanding of existing best practices, emerging research, and technologies. In consideration of Staff's recommendation, Appendix E, Cited Research and Informed Uses, discusses these participation efforts.
(28) Staff recommends Pacific Power and joint utilities evaluate the CPUC WSD maturity model and develop an Oregon IOU rubric as part of their 2024 WMPs; Staff would welcome the opportunity to participate in such a collaborative work effort.	As discussed in Section 0 (Industry Collaboration), Pacific Power, jointly with Portland General Electric and Idaho Power, aligned on the International Wildfire Risk Mitigation Consortium (IWRMC) maturity survey. The IWRMC representation presented at the staff recommendations meeting and the maturity survey confirmed the aligned approach to wildfire maturity for further collaboration in 2024.
(29) Staff recommends Pacific Power demonstrate the use of its ignition tracking database and process to perform root cause analyses which led to any ignition inspection program changes.	As discussed in Section 1.4 under Advanced Data Analytics Tool, Pacific Power is implementing the functionality to track fire incident data critical to validating modeled ignition risk and fire spread, updating assumptions, and refining calculations. As part of its industry collaboration efforts (as described in Section 0), Pacific Power will coordinate with Idaho Power and PGE to determine the feasibility of a common framework to evaluate the effectiveness of inspection programs in reducing wildfire risk, relative to cost.

APPENDIX C – WILDFIRE RISK MODELING DATA INPUTS

The following describes the general model inputs, data sources, update frequency, and update plans for data included in the company's planning and dynamic, seasonal risk model described in Sections 1.2 and 5.4. Many of the data sources below are provided and managed by Technosylva.

Dataset	Spatial Resolution (Meters)	Temporal Resolution	Data Vintage	Source
Landscape Characteristics				
Terrain	10	Yearly		United States Geological Survey (USGS)
Surface Fuels	30/10	Pre-Fire Season, Monthly Update in Fire Season, End of Fire Season	2020	Technosylva
Wildland Urban Interface (WUI) and Non-Forest Fuels Land Use	30/10	Twice A Year	2020	Technosylva
Canopy Fuels (CBD, CH, CC, CBH)	30/10	Pre-Fire Season, Monthly Update in Fire Season, End of Fire Season	2020	Technosylva
Roads Network	30	Yearly		USGS
Hydrography	30	Yearly		USGS
Croplands	30	Yearly	1997	USDA
Weather And Atmospheric Data				
Wind Speed	2000	Hourly / 96 Hour Forecast	1990	Atmospheric Data Solutions (ADS)
Wind Direction	2000	Hourly /96 Hour Forecast	1990	ADS
Wind Gust	2000	Hourly / 96 Hour Forecast	1990	ADS
Air Temperature	2000	Hourly / 96 Hour Forecast	1990	ADS
Surface Pressure	2000	Hourly / 96 Hour Forecast	1990	ADS
Relative Humidity	2000	Hourly / 96 Hour Forecast	1990	Technosylva
Precipitation	2000	Hourly / 96 Hour Forecast	1990	ADS
Radiation	2000	Hourly / 96 Hour Forecast	1990	ADS
Water Vapor Mixing Ratio 2 meter	2000	Hourly / 96 Hour Forecast	1990	ADS
Snow Accumulated – Observed	1000	Daily	2008	National Oceanic and Atmospheric Administration (NOAA)
Precipitation Accumulated - Observed	4000	Daily	2008	NOAA
Burn Scars	10	5 Days	2000	National Aeronautics and Space Administration (NASA)/ European Space Agency (ESA)

Dataset	Spatial Resolution (Meters)	Temporal Resolution	Data Vintage	Source
Weather Observations Data	Points	10 Min	1990	Synoptic
Fuel Moisture				
Herbaceous Live Fuel Moisture	250	Daily / 5-Day Forecast	2000	Technosylva
Woody Live Fuel Moisture	250	Daily / 5-Day Forecast	2000	Technosylva / ADS
1-Hour Dead Fuel Moisture	2000	Hourly / 124 Hour Forecast	1990	Technosylva / ADS
10-Hour Dead Fuel Moisture	2000	Hourly / 124 Hour Forecast	1990	Technosylva / ADS
100-Hour Dead Fuel Moisture	2000	Hourly / 124 Hour Forecast	1990	Technosylva / ADS
Values at Risk				
Buildings	Polygon Footprints	Yearly	2020-21	Microsoft/Technosylva
Damage Inspection (DINS)	Points	Yearly	2014-21	Cal Fire
Population	90	Yearly	2019	Landscan, Oak Ridge National Laboratory (ONRL)
Roads	Vector Lines	Yearly	2021	Caltrans
Social Vulnerability	Plexels	Yearly	2021	Esri Geoenrichment Service
Fire Stations	Points	Yearly	2021	Esri, USGS
Building Loss Factor	Building Footprints	Yearly	2022	Technosylva
Critical Facilities	Points	Yearly	2021	Fire Resource Assessment Program (FRAP), Cal Fire
Potential Ignition Locations				
Distribution & Transmission Lines	Linear Segments	Updated Quarterly	2022	Pacific Power
Poles & Equipment	Points	Updated Quarterly	2022	Pacific Power
Outage History	Points	Annual	1989-2022	Pacific Power
Ignition History	Points	Annual	2020-2022	Pacific Power
Fire Activity				
Hotspots MODIS	1000	Twice A Day	2000	NASA
Hotspots VIIRS	375	Twice A Day	2014	NASA
Hotspots GOES 16/17	3000	10 Minute	2019	NASA
Fireguard	Polygons	15 Minute	2020	National Guard
Fire Season Perimeters	Polygons	Daily	2021	National Incident Feature Service (NIFS)
Historic Fire Perimeters	Polygons	Yearly	1900	Cal Fire
Alert Wildfire Cameras	Live Feeds	1 Minute	Real Time	Alert Wildfire Consortium
Lighting Strikes	1000	1 Minute	Real Time	Earth Networks / Others

APPENDIX D – PLANNED PROJECTS

Below are the Oregon projects that Pacific Power has in execution or are scoping with the composite risk scores, if available. Projects with planned 2024 work have a high degree of confidence in their schedule. Projects are grouped by project type and sorted by circuit.

Circuit	Project Name / Scope	Average Distribution Composite Risk Score	Average Distribution Fuels/Terrain Driven Composite Risk Score	Average Distribution Wind Driven Composite Risk Score	Distribution Relay Construction Year	Distribution Line Reclosers	Communications	Covered Conductor	Covered Conductor Construction Year	Transmission Relay Construction Year	DFA Pilot	Expulsion Fuse Replacement Year	Weather Station Installation Year
Grid Hardening Projects													
068043/00	Days Creek to Dixonville - Replace Relays and Add Relay Comm Circuit									2025			
2R143	G Pass Sub: Replace Line 88 - BKR 2R143 relays									2021			
2R16	Grants Pass - Dowell N 2R16 Line 73 Relays									2023			
2R184	Cave Jct Sub: Replace Line 44S relays - BKRs 2R184/2R185 relays and add digital MW Comm to GPass									2022			
2R185	Cave Jct Sub: Replace Line 88 - BKRs 2R185/2R186 relays									2022			
2R186	Cave Jct Sub: Replace Line 44N - BKRs 2R186/2R189 relays									2022			
2R188	Cave Jct Sub: Replace Line 38 relays - BKRs 2R188/2R189 relays									2022			
2R2	Lost Creek - Prospect Central - Lone Pine - 2R2 Relays									2023			
2R26	Lone Pine - Lost Creek - Prospect Central - 2R26 Relays									2023			
2R27	Prospect Central Sub: Replace Line 12 - BKR 2R27 relays									2022			
2R30	Lone Pine - Prospect Central - Lost Creek - 2R30 Relays									2024			
2R8	Grants Pass - Dowell S 2R8 Line 76 Relays									2023			
2R9	G Pass Sub: Replace Line 44 - BKR 2R9 relays									2021			
2U1	Dixonville - Replace Bkr 2U1 Line Relays									2024			
2U151	Clearwater to Toketee - Replace 2U151 Line 51 Relays									2025			
2U153	Clearwater to Lemolo 1 - Replace 2U153 Line 53 Relays									2025			
2U157	Clearwater to Clearwater 1 - Replace 2U157 Line 57 Relays									2025			
2U2	Dixonville - Replace Bkr 2U2 Line Relays									2024			
2U20	Days Creek to Nickel Mtn - Replace BKR 2U20 Relays and Add Relay Comm Circuit									2025			
2U3	Dixonville - Replace Bkr 2U3 Line Relays									2024			
2U6	Dixonville - Replace Bkr 2U6 Line Relays									2024			
2U7	Nickel Mtn to Days Creek - Replace BKR 2U7 Relays and Add Relay Comm Circuit									2025			
2U8	Dixonville - Replace Bkr 2U8 Line Relays									2024			
2U9	Dixonville - Replace Bkr 2U9 Line Relays									2024			
2U90	Dixonville - Replace Bkr 2U90 and Relays									2024			
3L4	Klamath Falls Sub: Add T400L Pilot fault locating to 3L4									2023			
3L40	Klamath Falls - Hamaker BKR 3L40 Relays									2023			

Circuit	Project Name / Scope	Average Distribution Composite Risk Score	Average Distribution Fuels/Terrain Driven Composite Risk Score	Average Distribution Wind Driven Composite Risk Score	Distribution Relay Construction Year	Distribution Line Reclosers	Communications	Covered Conductor	Covered Conductor Construction Year	Transmission Relay Construction Year	DFA Pilot	Expulsion Fuse Replacement Year	Weather Station Installation Year
3R15	Applegate Sub: Replace Line 32 - BKR 3R15 relays									2024			
3R16	Prospect Central Sub: Replace Line 6 - BKR 3R16 relays									2022			
3R17	Prospect Central - Plant #3 - 3R17 Relays									2024			
3R245	CAVE JUNCTION 3R245 RLY Design Line 33									2020			
3R27	Grants Pass - Gold Hill 3R27 Relays									2023			
3R3	Lone Pine LN 6 3R3 Relays									2021			
3R30	Grants Pass - Beacon 3R30 Relays									2023			
3R90	Scenic - Gold Hill Relays									2023			
3U20	Dixonville - Replace Bkr 3U20 Line Relays									2024			
3U66	Roberts Creek - Myrtle Creek/RFP BKR 3U66 Relays									2023			
4D68	4D68 Warm Springs Sub Add HIF firmware upgrade and Add Comm/SCADA to sub and reclosers	0.23	0.22	0.18	2026	Y	2026						
4L50	4L50 Running Y Sub Replace DPU Relays with SEL 751s w/HIFD	0.11	0.15	0.05	2025	Y	2024						
4R1	4R1 Dodge Bridge Sub Add HiFD to SEL 751s for 4R1	0.24	0.27	0.16	2024	Y	2024						
4R13	4R13 Stevens Road Sub Add HIFD to SEL-751 relay for 4R13	0.33	0.27	0.32	2025		2025						
4R16	4R16 Stevens Road Sub Rplc DPU Relays with SEL 751s w/HIFD				2025		2025						
4R17	4R17 Stevens Road Sub Rplc DPU Relays with SEL 751s w/HIFD	0.31	0.28	0.26	2025	Y	2025						
4R33	4R33 Fielder Creek Sub Replace DPU relay with SEL-751 w/HIF	0.37	0.39	0.26	2023	Y	2023	Y	2025+		Y		
4R34	4R34 Fielder Creek Sub Replace DPU relay with SEL-751 w/HIF	0.42	0.48	0.25	2023	Y	2023	Y	2025+		Y		
4R35	4R35 Dodge Bridge Sub Rplc 4R35 Relay with SEL 751 w/HIFD	0.37	0.34	0.31	2024	Y	2024	Y	2025+				
4R41	4R41 Stevens Road Sub Rplc DPU Relays with SEL 751s w/HIFD	0.36	0.39	0.24	2025	Y	2025						
4R70	4R70 Dodge Bridge Sub Add HiFD to SEL 751s for 4R70				2024		2024						
4R9	4R9 Takelma Sub Replace 4R9 Relays with SEL-751 w/HIF	0.29	0.34	0.17	2023	Y	2023	Y	2025+		Y		
4U10	4U10 Roseburg Sub upgrade SEL 751 relay w/HIFD	0.11	0.16	0.05	2025	Y	2025						
4U18	4U18 Winchester Sub Add HIF firmware upgrade to SEL-751	0.19	0.24	0.09	2024	Y	2024						
4U22	4U22 Roseburg Sub Rplc DPU Relays with SEL 751s w/HIFD	0.26	0.31	0.16	2025	Y	2025						
4U23	4U23 Roseburg Sub Rplc DPU Relays with SEL 751s w/HIFD				2025		2025						
4U30	4U30 Southgate Sub Replace Relays with SEL 751s w/HIFD	0.22	0.25	0.13	2025	Y	2025						
4U31	4U31 Southgate Sub Replace Relays with SEL 751s w/HIFD	0.2	0.25	0.09	2025		2025						
4U38	4U38 Cloake Sub Rplc 4U38 Relays with SEL 751 w/HIFD	0.18	0.22	0.1	2026	Y	2026						
4U39	4U39 Cloake Sub Rplc 4U39 Relays with SEL 751 w/HIFD	0.32	0.36	0.2	2026	Y	2026						
4U5	4U5 Roseburg Sub Rplc DPU Relays with SEL 751s w/HIFD	0.16	0.2	0.07	2025	Y	2025						
4U80	4U80 Garden Valley Sub Replace Relays with SEL 751s w/HIFD	0.12	0.16	0.06	2025		2025						
4U81	4U81 Garden Valley Sub Add HIFD to SEL751	0.29	0.33	0.19	2025	Y	2025						
4W8	4W8 Enterprise Sub Replace Relays with SEL 751s w/HIFD	0.23	0.21	0.2	2026	Y	2026						
5K10	5K10 Hood River Sub Rplc DPU relay with SEL 751 w/HIFD				2022		2022						
5K37	5K37 Hood River Sub Rplc DPU relay with SEL-751 w/HIFD	0.17	0.22	0.07	2023	Y	2024				Y		
5K43	5K43 Hood River Sub Rplc DPU relay with SEL 751 w/HIFD	0.18	0.22	0.1	2023		2024						
5K44	5K44 Hood River Sub Rplc DPU relay with SEL 751 w/HIFD	0.12	0.17	0.03	2023		2024						

Circuit	Project Name / Scope	Average Distribution Composite Risk Score	Average Distribution Fuels/Terrain Driven Composite Risk Score	Average Distribution Wind Driven Composite Risk Score	Distribution Relay Construction Year	Distribution Line Reclosers	Communications	Covered Conductor	Covered Conductor Construction Year	Transmission Relay Construction Year	DFA Pilot	Expulsion Fuse Replacement Year	Weather Station Installation Year
5K70	5K70 Hood River Sub Replace DPU relay with SEL-751 w/HIFD	0.16	0.23	0.06	2023	Y	2024	Y	2024-2025		Y		
5K74	5K74 Hood River Sub Rplc DPU relay with SEL 751 w/HIFD	0.16	0.2	0.08	2023	Y	2024	Y	2021				
5L104	5L104 Mile Hi Sub Add HIF firmware upgrade and SCADA to SEL-751	0.41	0.31	0.4	2023		2023						
5L105	5L105 Mile Hi Sub Add SCADA to SEL751 and issue EFR settings	0.3	0.28	0.25	2025	Y	2025						
5L20	5L20 Turkey Hill Sub Replace Relays with SEL 751s w/HIFD	0.19	0.18	0.16	2026	Y	2026						
5L23	5L23 Turkey Hill Sub Add firmware upgrade and issue EFR settings	0.19	0.19	0.14	2026		2026						
5L230	5L230 Merrill Sub Replace bus-tie relays with SEL-751 w/HIF				2026		2026						
5L26	5L26 Merrill Sub Replace 5L26 relays with SEL-751 w/HIF	0.23	0.22	0.18	2026		2026						
5L27	5L27 Merrill Sub Add HIF firmware upgrade and issue EFR settings	0.26	0.25	0.2	2026		2026						
5L36	5L36 Modoc Sub Rplc DPU Relay with SEL 751s w/HIFD	0.16	0.19	0.1	2026		2026						
5L43	5L43 Dairy Sub Add HIFD to SEL 751 for 5L43	0.25	0.28	0.17	2024	Y	2024						
5L55	5L55 Hamaker Sub Replace Relays with SEL 751s w/HIFD	0.36	0.35	0.27	2026	Y	2026						
5L56	5L56 Hamaker Sub Add HIFD to SEL751	0.18	0.21	0.11	2026		2026						
5L57	5L57 Chiloquin Sub Rplc DPU Relay with SEL 751 w/HIFD	0.12	0.14	0.06	2024	Y	2024						
5L79	5L79 Turkey Hill Sub Add firmware upgrade and issue EFR settings				2026		2026						
5R103	5R103 Gold Hill Sub Rplc DPU Relay with SEL 751 w/HIFD	0.38	0.43	0.24	2024	Y	2024						
5R104	5R104 Beacon Sub Rplc 5R104 Relays with SEL 751 w/HIFD	0.14	0.18	0.06	2026		2026						
5R105	5R105 Beacon Sub Rplc 5R105 Relays with SEL 751 w/HIFD	0.11	0.15	0.04	2026		2026						
5R106	5R106 New O'Brien Sub Rplc DPU Relay with SEL 751 w/HIFD	0.35	0.42	0.19	2023	Y	2023	Y	2023-2025+		Y		
5R114	5R114 Park Street Rplc Breaker and add HIFD to SEL-751 relay	0.29	0.33	0.18	2024	Y	2024	Y	2025+				
5R115	5R115 Park Street Rplc Breaker and Relays with SEL-751 w/HIFD	0.14	0.18	0.07	2024	Y	2024						
5R120	5R120 Park Street Rplc Relays with SEL-751 equipped w/HIFD				2024		2024						
5R121	5R121 Park Street Rplc Relays with SEL-751 equipped w/HIFD	0.21	0.25	0.12	2024		2024						
5R123	5R123 Easy Valley Sub Rplc 5R123 Relays with SEL-751s w/HIFD	0.16	0.17	0.11	2024		2024						
5R125	5R125 Easy Valley Sub Rplc 5R125 Relays with SEL-751s w/HIFD	0.21	0.21	0.17	2024		2024						
5R133	5R133 Glendale Sub Rplc CB and relay with SEL-751 w/HIFD	0.38	0.47	0.2	2023	Y	2023	Y	2025+		Y		
5R143	5R143 Glendale Sub Rplc CB and relays with SEL-751 w/HIFD	0.25	0.3	0.15	2023	Y	2023	Y	2025+				
5R164	5R164 Park Street Rplc Relays with SEL-751 equipped w/HIFD	0.11	0.14	0.05	2024		2024						
5R169	5R169 Park Street Rplc Breaker and Relays with SEL-751 w/HIFD	0.11	0.15	0.05	2024		2024						
5R172	5R172 Agness Ave Sub Rplc DPU Relays with SEL 751s w/HIFD	0.34	0.4	0.2	2024	Y	2024	Y	2025+				
5R173	5R173 Agness Ave Sub Rplc DPU Relays with SEL 751s w/HIFD	0.32	0.38	0.18	2024	Y	2024						
5R174	5R174 Scenic Sub Replace Relays with SEL 751s w/HIFD	0.33	0.28	0.3	2026	Y	2026						
5R176	5R176 Scenic Sub Replace Relays with SEL 751s w/HIFD				2026		2026						
5R180	5R180 Scenic Sub Replace Relays with SEL 751s w/HIFD	0.17	0.2	0.1	2026	Y	2026						
5R182	5R182 Scenic Sub Replace Relays with SEL 751s w/HIFD	0.49	0.38	0.48	2026	Y	2026						
5R184	5R184 Scenic Sub Replace Relays with SEL 751s w/HIFD	0.2	0.19	0.16	2026		2026						
5R200	5R200 Griffin Creek Sub Rplc DPU Relay with SEL 751s w/HIFD	0.34	0.31	0.29	2025		2025						
5R204	5R204 Griffin Creek Sub Rplc DPU Relay with SEL 751s w/HIFD	0.16	0.19	0.09	2025		2025						
5R206	5R206 Griffin Creek Sub Rplc DPU Relay with SEL 751s w/HIFD	0.47	0.44	0.38	2025	Y	2025						
5R232	5R232 Merlin Sub Add HIFD to SEL 751 and comm to reclosers	0.44	0.45	0.32	2023	Y	2023	Y	2023-2025+		Y		

Circuit	Project Name / Scope	Average Distribution Composite Risk Score	Average Distribution Fuels/Terrain Driven Composite Risk Score	Average Distribution Wind Driven Composite Risk Score	Distribution Relay Construction Year	Distribution Line Reclosers	Communications	Covered Conductor	Covered Conductor Construction Year	Transmission Relay Construction Year	DFA Pilot	Expulsion Fuse Replacement Year	Weather Station Installation Year
5R234	5R234 Merlin Sub Add HIFD to SEL 751 for 5R234	0.35	0.37	0.24	2022		2023	Y	2024				
5R238	5R238 Talent Sub Replace Relays with SEL 751s w/HIFD	0.43	0.44	0.32	2025	Y	2025						
5R239	5R239 Talent Sub Replace Relays with SEL 751s w/HIFD	0.42	0.44	0.31	2025	Y	2025						
5R241	5R241 Ashland Sub Rplc 5R245 Relays with SEL 751 w/HIFD	0.29	0.28	0.23	2025		2025						
5R245	5R245 Ashland Sub Rplc 5R245 Relays with SEL 751 w/HIFD	0.49	0.39	0.48	2025	Y	2025						
5R248	5R248 Merlin Sub Add HIFD to SEL 751 and comm to reclosers	0.35	0.4	0.21	2023	Y	2023	Y	2023-2025+		Y		
5R249	5R249 Merlin Sub Add HIFD to SEL-751 for 5R249				2022		2023						
5R251	5R251 Merlin Sub Add HIFD to SEL-751 for 5R251	0.38	0.41	0.26	2022		2023						
5R258	5R258 Easy Valley Sub Rplc bus-tie 5R258 relays with SEL-751 w/HIFD				2024		2024	Y	2025+				
5R259	5R259 Easy Valley Sub upgrade SEL-751 w/HIFD	0.43	0.39	0.35	2024	Y	2024	Y	2025+				
5R267	5R267 Applegate Sub Rplc DPU Relays with SEL 751s w/HIFD	0.43	0.48	0.28	2022	Y	2023	Y	2025+				
5R278	5R278 Applegate Sub Rplc DPU Relays with SEL 751s w/HIFD	0.33	0.36	0.22	2022	Y	2023						
5R284	5R284 Jacksonville Sub Rplc DPU Relays with SEL 751s w/HIFD	0.42	0.42	0.33	2024	Y	2024						
5R285	5R285 Jacksonville Sub Rplc DPU Relays with SEL 751s w/HIFD	0.28	0.26	0.24	2024	Y	2024						
5R287	5R287 Humbug Creek Sub Replace Relays with SEL 751s w/HIFD	0.43	0.51	0.24	2025	Y	2025						
5R288	5R288 Merlin Sub Add HIFD to SEL 751 and comm to reclosers	0.36	0.38	0.25	2022	Y	2023	Y	2023-2025+				
5R294	5R294 Caveman Sub Rplc 5R294 Relays with SEL 751 w/HIFD				2026		2026						
5R295	5R295 Caveman Sub Rplc 5R295 Relays with SEL 751 w/HIFD	0.11	0.14	0.05	2026		2026						
5R312	5R312 Campbell Sub Rplc 5R312 Relays with SEL 751 w/HIFD	0.28	0.27	0.22	2026	Y	2026						
5R322	5R322 Agness Ave Sub Rplc DPU Relays with SEL 751s w/HIFD	0.12	0.16	0.04	2024		2024						
5R330	5R330 Dowell Sub Rplc 5R330 Relays with SEL 751 w/HIFD	0.17	0.18	0.12	2026		2026						
5R331	5R331 Dowell Sub Rplc 5R331 Relays with SEL 751 w/HIFD	0.17	0.19	0.11	2026		2026						
5R334	5R334 Dowell Sub Rplc 5R334 Relays with SEL 751 w/HIFD	0.27	0.28	0.19	2026	Y	2026						
5R335	5R335 Dowell Sub Rplc 5R335 Relays with SEL 751 w/HIFD				2026		2026						
5R372	5R372 Glendale Sub Rplc DPU2000R relay with SEL-751 w/HIFD				2022		2022						
5R40	5R40 Prospect Central Sub Rplc Relays with SEL 751s w/HIFD	0.28	0.32	0.16	2023		2023	Y	2025+				
5R52	5R52 Cave Junction Sub replace DPU relay with SEL 751 w/HIF	0.4	0.44	0.26	2023	Y	2023	Y	2024-2025+		Y		
5R53	5R53 Cave Junction Sub replace DPU relay with SEL 751 w/HIF	0.36	0.39	0.24	2023	Y	2023	Y	2024-2025+		Y		
5R55	5R55 Oak Knoll Sub replace CB and Add HIFD to SEL-751	0.32	0.33	0.24	2023	Y	2023	Y	2025+		Y		
5R56	5R56 Oak Knoll Sub replace CB and Add HIFD to SEL 751	0.42	0.45	0.29	2022	Y	2022						
5R62	5R62 Jerome Prairie Sub Rplc DPU relay with SEL-751 w/HIFD	0.43	0.48	0.27	2023	Y	2023	Y	2024-2025+		Y		
5R63	5R63 Jerome Prairie Sub Rplc CB 5R63 and Add HIF to SEL-751 and replace TPU2000R w/SEL 387	0.35	0.37	0.24	2023	Y	2023	Y	2025+		Y		
5R65	5R65 Selma Sub Rplc 5R65 Relay with SEL 751 w/HIFD	0.42	0.5	0.25	2023	Y	2024	Y	2023-2025+				
5R67	5R67 Provolt Sub Rplc 5R67 Relay with SEL 751 w/HIFD	0.4	0.4	0.3	2022	Y	2023						
5R68	5R68 Ruch Sub Replace DPU Relays with SEL 751s w/HIFD	0.34	0.4	0.21	2025	Y	2025						
5R69	5R69 Ruch Sub Replace DPU Relays with SEL 751s w/HIFD	0.34	0.42	0.18	2022		2022						
5R77	5R77 Rogue River Sub Rplc DPU Relays with SEL 751s w/HIFD	0.35	0.41	0.2	2023		2024	Y	2025+				
5R78	5R78 Rogue River Sub Rplc DPU Relays with SEL 751s w/HIFD	0.43	0.5	0.25	2023	Y	2024	Y	2025+				
5R82	5R82 Caveman Sub Rplc 5R82 Relays with SEL 751 w/HIFD	0.11	0.15	0.04	2026		2026						

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5R90	5R90 Tolo Sub Add HIFD to SEL751	0.43	0.32	0.43	2025		2025						
5R91	5R91 Tolo Sub Replace Relays with SEL 751s w/HIFD	0.42	0.42	0.32	2025	Y	2025						
5R98	5R98 Caveman Sub Rplc 5R98 Relays with SEL 751 w/HIFD	0.1	0.15	0.03	2026		2026						
5R99	5R99 Caveman Sub Rplc 5R99 Relays with SEL 751 w/HIFD	0.2	0.26	0.09	2026		2026		2025+				
5U1	5U1 Riddle Sub Rplc DPU Relay with SEL 751s w/HIFD	0.19	0.21	0.13	2024	Y	2024						
5U125	5U125 Riddle Sub Rplc DPU Relay with SEL 751 w/HIFD and TPUs w/SEL 387s				2024		2024						
5U134	5U134 Canyonville Sub Add HIFD to SEL 751s for 5U134				2024		2024						
5U15	5U15 Winchester Sub Rplc CB 5U15 and Relays with SEL-751 w/HIF	0.16	0.21	0.07	2024	Y	2024						
5U17	5U17 Winchester Sub Replace Relays with SEL 751s w/HIFD	0.3	0.32	0.2	2024	Y	2024						
5U19	5U19 Winchester Sub Rplc CB 5U19 and Relays with SEL-751 w/HIF	0.32	0.38	0.17	2024	Y	2024	Y	2025+				
5U2	5U2 Riddle Sub Rplc DPU Relay with SEL 751s w/HIFD	0.28	0.34	0.15	2024	Y	2024				Y		
5U23	5U23 Riddle Veneer Sub Rplc DPU Relays with SEL 751s w/HIFD	0.18	0.22	0.1	2024		2024						
5U3	5U3 Riddle Sub Rplc DPU Relay with SEL 751s w/HIFD	0.23	0.27	0.13	2024		2024						
5U46	5U46 Canyonville Sub Add HIFD to SEL 751s for 5U46	0.19	0.23	0.11	2024		2024						
5U48	5U48 Winston Sub Replace Relays with SEL 751s w/HIFD	0.11	0.14	0.04	2025		2025						
5U49	5U49 Winston Sub Replace Relays with SEL 751s w/HIFD	0.32	0.4	0.16	2025	Y	2025						
5U50	5U50 Riddle Veneer Sub Rplc DPU Relays with SEL 751s w/HIFD and TPU w/SEL-387E	0.21	0.25	0.12	2024	Y	2024						
5U52	5U52 Canyonville Sub Add HIFD to SEL 751s for 5U52	0.26	0.31	0.14	2024	Y	2024	Y					
5U76	5U76 Myrtle Creek Sub Rplc DPU Relays with SEL 751s w/HIFD	0.22	0.26	0.12	2022	Y	2023						
5U77	5U77 Myrtle Creek Sub Rplc DPU Relays with SEL 751s w/HIFD	0.24	0.29	0.13	2022	Y	2023	Y	2025+				
5U89	5U89 Tiller Sub Replace Relays with SEL 751s w/HIFD	0.28	0.35	0.14	2025	Y	2025						
5W13	5W13 Enterprise Sub Replace Relays with SEL 751s w/HIFD				2026		2026						
5W15	5W15 Enterprise Sub Replace Relays with SEL 751s w/HIFD	0.12	0.13	0.08	2026		2026						
5W21	5W21 Joseph Sub Replace Relays with SEL 751s w/HIFD	0.28	0.27	0.21	2025	Y	2025						
5W26	5W26 Enterprise Sub Replace Relays with SEL 751s w/HIFD	0.24	0.23	0.2	2026	Y	2026						
7R5	7R5 Red Blanket Sub Rplc 7R5 with self-contained CB & Add SCADA	0.17	0.22	0.08	2023	Y	2023	Y	2025+				
R114	Lincoln City R114 Add Recloser Comm & SCADA	0.15	0.19	0.07	2023	Y	2023						
Expulsion Fuse Replacement Projects													
5R173	Expulsion Fuse Replacement	0.32	0.38	0.18								2024	
5R278	Expulsion Fuse Replacement	0.33	0.36	0.22								2024	
4U31	Expulsion Fuse Replacement	0.20	0.25	0.09								2022-2024	
4U5	Expulsion Fuse Replacement	0.16	0.20	0.07								2022-2024	
5R103	Expulsion Fuse Replacement	0.38	0.43	0.24								2022-2024	
5R106	Expulsion Fuse Replacement	0.35	0.42	0.19								2022-2024	
5R172	Expulsion Fuse Replacement	0.34	0.40	0.20								2022-2024	
5R206	Expulsion Fuse Replacement	0.47	0.44	0.38								2022-2024	

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5R232	Expulsion Fuse Replacement	0.44	0.45	0.32								2022-2024	
5R239	Expulsion Fuse Replacement	0.42	0.44	0.31								2022-2024	
5R40	Expulsion Fuse Replacement	0.28	0.32	0.16								2022-2024	
5R77	Expulsion Fuse Replacement	0.35	0.41	0.20								2022-2024	
5U15	Expulsion Fuse Replacement	0.16	0.21	0.07								2022-2024	
5U17	Expulsion Fuse Replacement	0.30	0.32	0.20								2022-2024	
5U3	Expulsion Fuse Replacement	0.23	0.27	0.13								2022-2024	
5U46	Expulsion Fuse Replacement	0.19	0.23	0.11								2022-2024	
5U89	Expulsion Fuse Replacement	0.28	0.35	0.14								2022-2024	
7R5	Expulsion Fuse Replacement	0.17	0.22	0.08								2022-2024	
4L50	Expulsion Fuse Replacement	0.11	0.15	0.05								2023-2024	
4R1	Expulsion Fuse Replacement	0.24	0.27	0.16								2023-2024	
4R35	Expulsion Fuse Replacement	0.37	0.34	0.31								2023-2024	
4R41	Expulsion Fuse Replacement	0.36	0.39	0.24								2023-2024	
4R9	Expulsion Fuse Replacement	0.29	0.34	0.17								2023-2024	
4U10	Expulsion Fuse Replacement	0.11	0.16	0.05								2023-2024	
4U18	Expulsion Fuse Replacement	0.19	0.24	0.09								2023-2024	
4U30	Expulsion Fuse Replacement	0.22	0.25	0.13								2023-2024	
4U38	Expulsion Fuse Replacement	0.18	0.22	0.10								2023-2024	
4U80	Expulsion Fuse Replacement	0.12	0.16	0.06								2023-2024	
4U81	Expulsion Fuse Replacement	0.29	0.33	0.19								2023-2024	
4W8	Expulsion Fuse Replacement	0.23	0.21	0.20								2023-2024	
5K70	Expulsion Fuse Replacement	0.16	0.23	0.06								2023-2024	
5K74	Expulsion Fuse Replacement	0.16	0.20	0.08								2023-2024	
5L36	Expulsion Fuse Replacement	0.16	0.19	0.10								2023-2024	
5L43	Expulsion Fuse Replacement	0.25	0.28	0.17								2023-2024	
5L55	Expulsion Fuse Replacement	0.36	0.35	0.27								2023-2024	
5L56	Expulsion Fuse Replacement	0.18	0.21	0.11								2023-2024	
5L57	Expulsion Fuse Replacement	0.12	0.14	0.06								2023-2024	
5R174	Expulsion Fuse Replacement	0.33	0.28	0.30								2023-2024	
5R182	Expulsion Fuse Replacement	0.49	0.38	0.48								2023-2024	
5R241	Expulsion Fuse Replacement	0.29	0.28	0.23								2023-2024	
5R245	Expulsion Fuse Replacement	0.49	0.39	0.48								2023-2024	
5R248	Expulsion Fuse Replacement	0.35	0.40	0.21								2023-2024	
5R284	Expulsion Fuse Replacement	0.42	0.42	0.33								2023-2024	
5R285	Expulsion Fuse Replacement	0.28	0.26	0.24								2023-2024	
5R287	Expulsion Fuse Replacement	0.43	0.51	0.24								2023-2024	
5R312	Expulsion Fuse Replacement	0.28	0.27	0.22								2023-2024	
5R53	Expulsion Fuse Replacement	0.36	0.39	0.24								2023-2024	

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5R62	Expulsion Fuse Replacement	0.43	0.48	0.27								2023-2024	
5R63	Expulsion Fuse Replacement	0.35	0.37	0.24								2023-2024	
5R65	Expulsion Fuse Replacement	0.42	0.50	0.25								2023-2024	
5R69	Expulsion Fuse Replacement	0.34	0.42	0.18								2023-2024	
5R90	Expulsion Fuse Replacement	0.43	0.32	0.43								2023-2024	
5R91	Expulsion Fuse Replacement	0.42	0.42	0.32								2023-2024	
5R98	Expulsion Fuse Replacement	0.10	0.15	0.03								2023-2024	
5U1	Expulsion Fuse Replacement	0.19	0.21	0.13								2023-2024	
5U2	Expulsion Fuse Replacement	0.28	0.34	0.15								2023-2024	
5U49	Expulsion Fuse Replacement	0.32	0.40	0.16								2023-2024	
5U50	Expulsion Fuse Replacement	0.21	0.25	0.12								2023-2024	
5U76	Expulsion Fuse Replacement	0.22	0.26	0.12								2023-2024	
5U77	Expulsion Fuse Replacement	0.24	0.29	0.13								2023-2024	
5W21	Expulsion Fuse Replacement	0.28	0.27	0.21								2023-2024	
Weather Station Installations													
4L16	Brady Butte	0.26	0.26	0.19									2024
4L16	Gerber Rd	0.26	0.26	0.19									2024
4L16	Power Line Rd	0.26	0.26	0.19									2024
4L50	Aspen Lake	0.11	0.15	0.05									2024
4M185	Philomath South	0.18	0.19	0.12									2024
4M209	Dawson Rd	0.19	0.20	0.13									2024
4M360	Creswell	0.16	0.20	0.09									2024
4U18	Forgotten Ln	0.19	0.24	0.09									2024
4U5	SE Summit	0.16	0.20	0.07									2024
4U81	Red Hill	0.29	0.33	0.19									2024
5A83	Crown Camp Rd	0.08	0.11	0.03									2024
5A92	Bear Creek Reservoir	0.19	0.23	0.10									2024
5A93	Columbia River Hwy	0.20	0.26	0.09									2024
5A93	Koppisch Rd	0.20	0.26	0.09									2024
5L43	Grizzly Ln	0.25	0.28	0.17									2024
5L55	Round Lake Ridge	0.36	0.35	0.27									2024
5R143	Panther Creek	0.25	0.30	0.15									2024
5R206	Griffin	0.47	0.44	0.38									2024
5U2	Riddle Bypass	0.28	0.34	0.15									2024
5U44	Roberts Creek Valley	0.23	0.27	0.13									2024
5U44	Round Prairie East	0.23	0.27	0.13									2024
6U13	Illahee Flats	0.32	0.41	0.15									2024

APPENDIX E – COLLABORATION AND INDUSTRY LEARNINGS

MATURITY SURVEY SUMMARY

IWRC Category	Oregon WMP Section	Program	Maturity Progression
Category A: Risk Mapping and Simulation	Section 1 – Risk Modeling and Drivers	Advanced Data Analytics	2023: FireSight model will progress to a regular review of the model. 2024: Increased model capabilities with quarterly updates for asset information in the WFA-E and conducting regular reviews of the model results. 2025: Enhanced circuit level forecast with the estimated probability of ignition at a circuit level, creating a circuit level specific weather forecast, increasing the modeling inputs for PSPS risk reduction estimations, and have a climate change impact on a circuit level.
Category B: Situational Awareness & Forecasting	Section 5 – Situational Awareness	Camera Detection Network HPCC Capacity Increase	2024: Implement a wildfire camera detection network. 2026: Implement additional high performance computing clusters to accelerate forecasting and incorporate multi-member Weather Research Forecast (WRF) ensembles.
Category C: Grid Design and System Hardening	Section 4 – System Hardening	Early Fault Detection	2024: Implement new technologies for continuous monitoring on the transmission lines.
Category G: Data Management and Governance	Section 1 – Risk Modeling and Drivers	Advanced Data Analytics	2025: Utilize machine learning and other advanced approaches to continually refine and improve algorithms and predictive model accuracy.

INDUSTRY AND REGULATORY ENGAGEMENT AND FORUMS

Below is the list of industry and regulatory meetings with verified Pacific Power attendance.

Date	Meeting	State	Agency	Topic	PacifiCorp Attendee Role/Team
2/15/2023	READi: Workstream 1	All	EPRI	Technical Advisors Meeting	Manager Meteorology
2/22/2023	READi: Workstream 2	All	EPRI	Climate Asset: Technical Advisors Meeting	Director Asset Management
3/17/2023	Fast Trip, Unplanned Outages, and Distribution Reliability Workshop	CA	CPUC	Fast Trip, Unplanned Outages, and Distribution Reliability Workshop	Director, Protection and Control
3/22/2023	READi: Oversight Committee	All	EPRI	Oversight Committee Meeting	VP Engineering & T&D Standards
4/25/2023-4/27/23	READi: Workstream 2	All	EPRI	Climate Asset Workshop	Director Asset Management
5/11/2023-5/12/23	READi: Workstream 1	All	EPRI	Workstream 1 Workshop	Manager, Meteorology
5/23/2023	READi: Workstream 2	All	EPRI	Joint Technical Advisors & Affinity Group Meeting	Director Asset Management
6/5/2023	Joint IOU Working Group: New Technologies and Alternatives	CA	OEIS	EFR/Fast Curve Settings: Preparation for 6/21 Meeting	Principal Engineer, Engineering Standards and Grid Modernization, Manager, Data Science
6/6/2023	PacifiCorp-Energy Safety Biweekly Meeting	CA	OEIS	Progress Updates: Grid Hardening and Vegetation Management	Director, Wildfire Mitigation Program Delivery
6/14/2023	READi	All	EPRI	Oversight Committee (ROC) Meeting	VP Engineering & T&D Standards
6/14/2023	Risk Modeling Working Group	CA	OEIS	Ingress and Egress Fire Models	Manager, Data Science
6/16/2023	SMJU Workshop	CA	OEIS	2023-2025 WMP	Director, Wildfire Mitigation Program Delivery
6/20/2023	Joint IOU Working Group: New Technologies and Alternatives	CA	OEIS	EFR/Fast Curve Settings: Preparation for 6/21 Meeting	Principal Engineer, Engineering Standards and Grid Modernization, Manager, Data Science

Date	Meeting	State	Agency	Topic	PacifiCorp Attendee Role/Team
6/20/2023	PacifiCorp-Energy Safety Biweekly Meeting	CA	OEIS	Progress Update: Vegetation Management	Director, Wildfire Mitigation Program Delivery
6/21/2023	Joint IOU Working Group: New Technologies and Alternatives	CA	OEIS	EFR/Fast Curve Settings	Principal Engineer, Engineering Standards and Grid Modernization, Manager, Data Science
6/21/2023	Northern California Cal Fire Site Visit	CA	Cal Fire	PSPS Preparedness, Grid Hardening, Vegetation Management	Program Manager, Wildfire Mitigation Program Delivery
7/11/2023	Joint IOU Working Group	CA	OEIS	Central Valley RWQC	Program Manager, Wildfire Mitigation Program Delivery
7/11/2023	Risk Modeling Working Group	CA	OEIS	Approaches to Modeling Long Duration, High intensity Wildfires	Manager, Data Science
7/13/2023	Joint IOU Working Group: New Technologies and Alternatives	CA	OEIS	Distribution Fault Anticipation (DFA)	Business Integration Manager, Wildfire Mitigation Program Delivery
7/13/23-7/14/23	OEIS Workshop	CA	OEIS	Workshop on Addressing GO Safety Standards	Project Manager, Wildfire Mitigation Program Delivery
7/17/2023	Joint IOU Working Group: New Technologies and Alternatives	CA	OEIS	Distribution Fault Anticipation (DFA)	Principal Engineer, Engineering Standards and Grid Modernization
7/21/2023	Joint IOU Working Group: M&I Practices	CA	OEIS	Prep for July 24 Workshop	Business Integration Manager, Wildfire Mitigation Program Delivery
7/24/2023	Joint IOU Working Group: M&I Practices	CA	OEIS	M&I Training Practices	Asset Planning Manager, Asset Management
7/31/2023	Joint IOU: New Technologies and Alternatives	CA	OEIS	Preparation for September 20 workshop on Early Fault Discharge (EFD)	Director and Principal Engineer, Engineering Standards and Grid Modernization
8/2/2023	Joint IOU Working Group: 2023 OR WMP Recommendations	OR	OPUC	Engagement plan and clarification of recommendations with IOUs and Staff	Director, Wildfire Mitigation Program Delivery, State Regulatory Affairs Manager, and Project Manager Wildfire Mitigation Program Delivery
8/2/2023	Joint IOU WMP Recommendations	CA	OEIS	WMP Recommendations	Director, Wildfire Mitigation Program Delivery

Date	Meeting	State	Agency	Topic	PacifiCorp Attendee Role/Team
8/7/2023	Joint IOU Working Group: Estimated and Recorded Effectiveness	CA	OEIS	Covered Conductor Testing Results	Business Integration Manager, Wildfire Mitigation Program Delivery
8/9/2023	Risk Modeling Working Group	CA	OEIS	PSPS Planning Models	Director, Asset Risk, Manager, Data Science
8/14/2023	Joint IOU: New Technologies and Alternatives	CA	OEIS	Prep for September Meeting	Principal Engineer, Engineering Standards and Grid Modernization
8/16/2023	READi: Workstream 1	All	EPRI	Technical Advisors Meeting	Manager Meteorology
8/21/2023	Joint IOU Working Group: 2023 OR WMP Recommendations	OR	OPUC	Maturity Model and Effectiveness of Customer Outreach	Director, Wildfire Mitigation Program Delivery
8/21/2023	Joint IOU Working Group: Estimated and Recorded Effectiveness	CA	OEIS	Next steps in testing effectiveness	Business Integration Manager, Wildfire Mitigation Program Delivery
8/22/2023	Joint IOU Working Group: 2023 OR WMP Recommendations	OR	OPUC	Meeting with OPUC Staff on Recommendations	VP Wildfire & Asset Management, Director Wildfire Mitigation Program Delivery, and Project Manager Wildfire Mitigation Program Delivery
8/22/2023	READi: Workstream 2	All	EPRI	Technical Advisors Meeting	Director Asset Management
8/28/2023	Joint IOU Working Group: Covered Conductor Effectiveness: New Technologies	CA	OEIS	Prep for meeting with OEIS on EFD equipment	Principal Engineer, Engineering Standards and Grid Modernization
9/6/2023	READi	All	EPRI	Oversight Committee (ROC) Meeting	VP Engineering & T&D Standards
9/11/2023	Joint IOU: New Technologies and Alternatives	CA	OEIS	Preparation for Early Fault Detection (EFD) meeting with Energy Safety	Principal Engineer, Engineering Standards and Grid Modernization
9/12/2023	Joint IOU Working Group: 2023 OR WMP Recommendations	OR	OPUC	Meeting with OPUC Staff on Recommendations	Director, Wildfire Mitigation Program Delivery, Director Asset Risk, and Project Manager Wildfire Mitigation Program Delivery
9/14/2023	Risk Modeling Working Group	CA	OEIS	Avoiding Bias in Wildfire Probability Modeling	Director, Asset Risk
9/19/2023	Joint IOU Working Group: Covered Conductor Coordination	CA	OEIS	Reporting on ACIs	Business Integration Manager, Wildfire Mitigation Program Delivery

Date	Meeting	State	Agency	Topic	PacifiCorp Attendee Role/Team
9/20/2023	OR Wildfire Mitigation Pacific Power + OPUC Staff meeting	OR	OPUC	Discuss PAC only recommendations	Director and Project Manager Wildfire Mitigation Program Delivery, Director, Asset Risk, Director, Emergency Management, Director, Asset Management, Project Manager, Regulatory Policy and Operations,
9/20/2023	Joint IOU: New Technologies and Alternatives	CA	OEIS	Early Fault Detection (EFD)	Director and Principal Engineer, Engineering Standards and Grid Modernization
9/25/2023	Joint IOU: New Technologies and Alternatives	CA	OEIS	EFD benchmarking survey development	Principal Engineer, Engineering Standards and Grid Modernization
10/5/2023	Joint IOU Working Group: 2023 OR WMP Recommendations	OR	OPUC	Meeting with OPUC Staff on Recommendations	Director, Wildfire Mitigation Program Delivery, Director Asset Risk, and Project Manager Wildfire Mitigation Program Delivery
10/9/2023	Joint IOU: New Technologies and Alternatives	CA	OEIS	Preparation for November 8 workshop on Rapid Earth Fault Current Limiter (REFCL)	Business Integration Manager, Wildfire Mitigation Program Delivery
10/11/2023	Risk Modeling Working Group	CA	OEIS	Standardized Risk Type Classifications and in Situ Wildfire Risk Assessment	Director, Asset Risk, Manager, Data Science
10/16/2023	Joint IOU: Wildfire Protection Settings & R&D	OR	OPUC	Wildfire Protection Setting methodology; Lessons Learned o Effectiveness and reliability o Updates/changes that have been incorporated based on learnings Future plans	Director, Protection and Control
10/17/2023	Joint IOU Working Group: Covered Conductor Coordination	CA	OEIS	Measuring mitigation effectiveness	Business Integration Manager, Wildfire Mitigation Program Delivery
10/19/2023	Risk Management Workgroup Monthly Meeting	All	IWRMC	Vendor Presentation: ABB - Powerful CB Fault Current Limiting Circuit Breaker (FLCB) Pilot	Project Manager, Wildfire Mitigation Program Delivery
10/23/2023	Joint IOU: New Technologies and Alternatives	CA	OEIS	Preparation for November 8 workshop on Rapid Earth Fault Current Limiter (REFCL)	Principal Engineer, Engineering Standards and Grid Modernization
10/26/2023	Data Management & Governance Quarterly Meeting	All	IWRMC	PG&E Wildfire Dashboards & Ignition Data Sharing External Presentation: Dryad	Project Manager, Wildfire Mitigation Program Delivery

Date	Meeting	State	Agency	Topic	PacifiCorp Attendee Role/Team
				Member Presentation: Essential Energy's Data Governance Journey	
11/7/2023	Operations & Protocols Workgroup Quarterly Webinar	All	IWRMC	KPI Discussion: Member Wildfire Metrics Maturity Model use and application	Project Manager, Wildfire Mitigation Program Delivery
11/8/2023	Asset Management Workgroup Quarterly Webinar	All	IWRMC	Vender Presentation: NV Energy - Sharper Shape Member Presentation: PGE - Pano Camera Technology and Deployment	Project Manager, Wildfire Mitigation Program Delivery
11/8/2023	Joint IOU: New Technologies and Alternatives	CA	OEIS	Rapid Earth Fault Current Limiter (REFCL)	Principal Engineer, Engineering Standards and Grid Modernization
11/8/2023	Risk Modeling Working Group	CA	OEIS	Model Maintenance and Data Collection	Director, Asset Risk, Manager, Data Science
11/8/2023	READi: Annual Workshop	All	EPRI	•Company Profile •Stakeholder Engagement •Peer-2-Peer On the Spot Benchmarking •READi Adjacent Updates	VP Engineering & T&D Standards
11/9/2023	READi: Annual Workshop	All	EPRI	•Physical Climate Data Guidance: WS1 Update and Discussion •Case Study: Localizing Climate Information Illustrative Analysis •Asset Exposure and Vulnerability: WS2 Update & Discussion •Case Study: Climate Vulnerability Assessment – A Nuclear Facility Pilot	VP Engineering & T&D Standards
11/9/2023	Joint IOU Meeting with OPUC Staff	OR	OPUC	Discuss lessons learned from 2023; WMP review and approval process; Review and collaborate on a proposed 2024 WMP review and approval process	VP Wildfire & Asset Management, State Regulatory Affairs Manager, and Project Manager Wildfire Mitigation Program Delivery
11/15/2023	READi: Workstream 1	All	EPRI	Joint Technical Advisors & Affinity Group Meeting	Manager Meteorology
11/15/2023	Vegetation Management Workgroup Quarterly Webinar	All	IWRMC	Vendor Presentation: Sentient Energy - Predictive Analytics for Detecting Vegetation Contact on Power Lines Roundtable Discussion: Network-	Project Manager, Wildfire Mitigation Program Delivery

Date	Meeting	State	Agency	Topic	PacifiCorp Attendee Role/Team
				initiated efforts to address labor shortages Maturity Model Review: Category - 23. Vegetation grow-in inspection and trimming / treatment process & cycles	
11/16/2023	Risk Management Workgroup Quarterly Webinar	All	IWRMC	Vendor Presentation: Ororatech – Wildfire Risk Modeling Detailed Topic: Wildfire Model Calibration, based on prompts from Essential Energy	Project Manager, Wildfire Mitigation Program Delivery
12/5/2023	Asset Management Workgroup Monthly Meeting	All	IWRMC	Member Presentation: Climate Change and Asset Resilience – Alex Hoon, NV Energy Member Presentation: IML-RESI System – Karl Harrison, Powercor	Project Manager, Wildfire Mitigation Program Delivery
12/11/2023	Joint IOU Working Group: Estimated and Recorded Effectiveness	CA	OEIS	Outage Risk Drivers	Director, Asset Risk, Manager, Data Science
12/13/2023	Vegetation Management Workgroup Monthly Meeting	All	IWRMC	External Presentation: Recent legal & regulatory improvement recommendations to CA's Wildfire Safety Advisory Board – Lawrence Kahn, UVM Institute Member Presentation: Body Worn Cameras for Field Personnel Security – Spencer Few, AusNet	Project Manager, Wildfire Mitigation Program Delivery
12/13/2023	Risk Modeling Working Group	CA	OEIS	Review of Wildfire Related Operational Models	Manager Meteorology, Director, Asset Risk, Director, Wildfire Mitigation Program Delivery
12/20/2023	2024 WMP Review Plan	OR	OPUC	Joint IOU call with OPUC Staff to review 2024 plan for data requests and workshops	VP Wildfire & Asset Management

CITED RESEARCH AND INFORMED USES

Initiative	Date	Title	Proprietary or Confidential Information	Publisher	Topic
Annual FireSight (WRRM) Planning Model Updates	Apr-23	PG&E 2023-2025 Wildfire Mitigation Plan	No	PG&E	Composite Risk Variables
Annual FireSight (WRRM) Planning Model Updates	Apr-23	SCE 2023-2025 Wildfire Mitigation Plan	No	Southern California Edison	Composite Risk Variables
Annual FireSight (WRRM) Planning Model Updates	Apr-23	SDG&E 2023-2025 Wildfire Mitigation Plan	No	San Diego Gas & Electric	Composite Risk Variables
Risk Spend Efficiency (RSE) Model Refresh	23-Oct	2023 -2025 WMP Joint IOU Covered Conductor Working Group Report	No	PG&E	Effectiveness of Covered Conductor
Evaluation of Impacts of Climate Change on Risk Models	Jul-23	Scoping Meeting: Climate Change and Fire Risk-Consequence Modeling	No	California Office of Energy Infrastructure Safety (OEIS)	Climate Change and Fire Risk-Consequence Modeling
FHCA Refresh	May-23	Independent Review Team Report on the Production of the California Public Utility Commission's Statewide Fire Map 2	No	OEIS	Discussion of approach for developing California's High Fire Threat District Maps
FHCA Refresh	May-23	OPUC OAR 860-300-0030	No	Oregon Public Utility Commission (OPUC)	Identification of regulatory requirements for establishing FHCAs such as thresholds, buffers, etc.

Initiative	Date	Title	Proprietary or Confidential Information	Publisher	Topic
FHCA Refresh	May-23	Fire-Threat Maps and Fire-Safety Rulemaking	No	California Public Utility Commission (CPUC)	Identification of regulatory requirements for establishing FHCAs such as thresholds, buffers, etc.
FHCA Refresh	May-23	IPUC Rules	No	Idaho Public Utility Commission	Identification of regulatory requirements for establishing FHCAs such as thresholds, buffers, etc.
FHCA Refresh	May-23	R746 Rules	No	Utah Office of Administrative Services:	Identification of regulatory requirements for establishing FHCAs such as thresholds, buffers, etc.
FHCA Refresh	May-23	Title 54 Public Utilities	No	Utah State Legislature	Identification of regulatory requirements for establishing FHCAs such as thresholds, buffers, etc.
FHCA Refresh	May-23	Title 80: Public Utilities	No	Washington State Legislature	Identification of regulatory requirements for establishing FHCAs such as thresholds, buffers, etc.
FHCA Refresh	May-23	Public Service Commission Rules	No	State of Wyoming	Identification of regulatory requirements for establishing FHCAs such as thresholds, buffers, etc.

Initiative	Date	Title	Proprietary or Confidential Information	Publisher	Topic
FHCA Refresh	May-23	Oregon Explorer: Wildfire Risk	No	Oregon Department of Forestry and US Forest Service	Identification of wildfire risk levels as assessed by the State
FHCA Refresh	May-23	Wyoming Wildfire Risk Assessment Portal	No	Wyoming State Forestry Division	Identification of wildfire risk levels as assessed by the State
Annual FireSight (WRRM) Planning Model Updates	Jan-23	Model Documentation	Yes	Technosylva	Describes science and methodology underlying models
Annual FireSight (WRRM) Planning Model Updates	Jun-23	Technosylva POF Model Documentation	Yes	Technosylva	Describes how probability of failure is calculated for understanding of risk models
Annual FireSight (WRRM) Planning Model Updates	Sep-22	Weather Day Selection	Yes	Technosylva	Describes how weather days were selected for risk model

APPENDIX F – PROGRAM GOALS

Below is a table showing the milestones per year for the programs described throughout the document.

	2023 Goals	2024 Goals	2025 Goals	2026 Goals	2027 Goals	2028 Goals
Risk Modeling and Drivers						
FHCA Baseline Risk Refresh	Deliver updated FHCA Baseline Risk map.	Release refreshed map to operations				Perform baseline risk map update
Risk Assessment and Reduction	Deliver updated composite risk and RSE calculations and domain expansion.	Annual model verification with updates to the composite risk and RSE calculations	Annual model verification with updates to the composite risk and RSE calculations	Annual model verification with updates to the composite risk and RSE calculations	Annual model verification with updates to the composite risk and RSE calculations	Annual model verification with updates to the composite risk and RSE calculations
Advanced Data Analytics	Improve outage tracking and event reporting.	Improve outage tracking and event reporting.	Improve outage tracking and event reporting.	Analyze new features based on need and gap analysis	Analyze new features based on need and gap analysis	Analyze new features based on need and gap analysis
Asset Inspection & Correction - Perform incremental inspections as part of the wildfire mitigation program.[43]						
Overhead Safety Patrol Inspection	55,000 (Structures)	60,250 (AVG Structures)	60,250 (AVG Structures)	60,250 (AVG Structures)	60,250 (AVG Structures)	60,250 (AVG Structures)
Overhead Detail Inspection	11,000 (Structures)	12,050 (AVG Structures)	12,050 (AVG Structures)	12,050 (AVG Structures)	12,050 (AVG Structures)	12,050 (AVG Structures)
Infrared Inspection	2,000(mi)	2,000(mi)	2,000(mi)	2,000(mi)	2,000(mi)	2,000(mi)

[43] Asset inspection and correction numbers are average structure numbers from the 2018 FHCA.

	2023 Goals	2024 Goals	2025 Goals	2026 Goals	2027 Goals	2028 Goals
Vegetation Management - Perform incremental vegetation inspections and mitigations as part of the wildfire mitigation program.[44]						
Vegetation Inspections and Mitigations	1,500 (mi)	1,500 (mi)	1,500 (mi)	1,500 (mi)	1,500 (mi)	1,500 (mi)
Vegetation Pole Clearing	26,130 (poles)	26,000 (poles)	26,000 (poles)	26,000 (poles)	26,000 (poles)	26,000 (poles)
Vegetation Inspection Transition to 3yr Cycle	200(mi)	200(mi)	-	-	-	-
System Hardening						
Line Rebuild	125 (mi)	125 (mi)	125 (mi)	125 (mi)	125 (mi)	125 (mi)
System Automation	65 (devices)	65 (devices)	65 (devices)	65 (devices)	65 (devices)	65 (devices)
Fuse Replacement	10,500 (devices)	9,000 (devices)	5,500 (devices)	5,500 (devices)	5,500 (devices)	5,500 (devices)
Communicating Fault Indicators		300 (devices)				
Communicating Fault Indicators Data	1,100 (devices)	1,400 (devices)	1,400 (devices)	1,400 (devices)	1,400 (devices)	1,400 (devices)
Fast Trip Fault Indicators	-	2500 (devices)	2500 (devices)		2500 (devices)	TBD
Early Fault Detectors (pilot)	-	4 (devices)	TBD	TBD	TBD	TBD

44 The line miles and poles are based off the 2018 FHCA.

	2023 Goals	2024 Goals	2025 Goals	2026 Goals	2027 Goals	2028 Goals
Facility Lease	Leased facility space in strategic locations to decrease delays in line rebuild construction projects	Leased facility space in strategic locations to decrease delays in line rebuild construction projects	Leased facility space in strategic locations to decrease delays in line rebuild construction projects	Leased facility space in strategic locations to decrease delays in line rebuild construction projects	Leased facility space in strategic locations to decrease delays in line rebuild construction projects	Leased facility space in strategic locations to decrease delays in line rebuild construction projects
System Allocated*	Oregon's portion of the system allocation transmission spend.	Oregon's portion of the system allocation transmission spend.	Oregon's portion of the system allocation transmission spend.	Oregon's portion of the system allocation transmission spend.	Oregon's portion of the system allocation transmission spend.	Oregon's portion of the system allocation transmission spend.
Situational Awareness						
Meteorology Department	Meteorologists supporting the weather station placement and operational weather forecasting	Meteorologists supporting the weather station placement and operational weather forecasting	Meteorologists supporting the weather station placement and operational weather forecasting	Meteorologists supporting the weather station placement and operational weather forecasting	Meteorologists supporting the weather station placement and operational weather forecasting	Meteorologists supporting the weather station placement and operational weather forecasting
Operational Weather Forecasting	Improve integration of weather data into internal systems. Full integration of the 30yr historic weather data analysis into operational planning processes. Necessary software subscriptions.	Implement improvements to weather forecasting and develop machine learning improvements to situational awareness websites. Design infrastructure needed to implement a multiple WRF ensemble. Necessary software subscriptions.	Improve weather forecasting systems, identify refinements for the FPI calculations, and build out the computing clusters needed for additional modeling capabilities. Necessary software subscriptions.	Full implementation of WRF ensembles with accelerated forecasting, identified refinements to the FPI model are updated. New computing systems online to manage additional modeling. Necessary software subscriptions.	Implement refinements to the FPI model and calculations, hosting support and maintenance for the computed clusters and accelerated forecasting capabilities. Necessary software subscriptions.	Implement refinements to the FPI model and calculations, hosting support and maintenance for the computed clusters and accelerated forecasting capabilities. Necessary software subscriptions.

	2023 Goals	2024 Goals	2025 Goals	2026 Goals	2027 Goals	2028 Goals
Weather Station Installs	47 (devices)	25 (devices)	17 (devices)	8 (devices)	5 (devices)	5 (devices)
Weather Station Maintenance and Data	102 (devices)	155 (devices)	180 (devices)	197 (devices)	205 (devices)	210 (devices)
Wildfire Detection Network	5 (devices)	Annual maintenance for installed cameras	Annual maintenance for installed cameras	Annual maintenance for installed cameras	Annual maintenance for installed cameras	Annual maintenance for installed cameras
System Operations						
EFR Settings	Field labor to implement EFR setting upon the daily risk assessment	Field labor to implement EFR setting upon the daily risk assessment	Field labor to implement EFR setting upon the daily risk assessment	Field labor to implement EFR setting upon the daily risk assessment	Field labor to implement EFR setting upon the daily risk assessment	Field labor to implement EFR setting upon the daily risk assessment
Field Operations & Work Practices						
PSPS Watch Patrols	High-risk patrols that are not PSPS events	High-risk patrols that are not PSPS events	High-risk patrols that are not PSPS events	High-risk patrols that are not PSPS events	High-risk patrols that are not PSPS events	High-risk patrols that are not PSPS events
Fire Preparedness Equipment	Field tools for wildfire mitigation	Field tools for wildfire mitigation	Field tools for wildfire mitigation	Field tools for wildfire mitigation	Field tools for wildfire mitigation	Field tools for wildfire mitigation
Rapid Response Communications	2 COWs 6 Starlink	Data plans for communications devices	Data plans for communications devices	Data plans for communications devices	Data plans for communications devices	Data plans for communications devices
Training Applications and eBooks	Development of WMP training applications and eBooks	Delivery of training applications and eBooks				

	2023 Goals	2024 Goals	2025 Goals	2026 Goals	2027 Goals	2028 Goals
PSPS Program						
PSPS Event	Work associated with a PSPS event	Work associated with a PSPS event	Work associated with a PSPS event	Work associated with a PSPS event	Work associated with a PSPS event	Work associated with a PSPS event
Battery Rebate Program	Delivery of rebate portal, website updates, and customer communications.	200 rebates issued	200 rebates issued	200 rebates issued	200 rebates issued	200 rebates issued
Public Safety Partner Coordination						
Tabletop Exercises	2 tabletop exercises performed	Potential of 8 tabletop exercises performed	Potential of 8 tabletop exercises performed	Potential of 8 tabletop exercises performed	Potential of 8 tabletop exercises performed	Potential of 8 tabletop exercises performed
Emergency Management Team	Emergency management teams work for preparedness and action during PSPS watch and PSPS events	Emergency management teams work for preparedness and action during PSPS watch and PSPS events	Emergency management teams work for preparedness and action during PSPS watch and PSPS events	Emergency management teams work for preparedness and action during PSPS watch and PSPS events	Emergency management teams work for preparedness and action during PSPS watch and PSPS events	Emergency management teams work for preparedness and action during PSPS watch and PSPS events
WMP Engagement Strategy						

	2023 Goals	2024 Goals	2025 Goals	2026 Goals	2027 Goals	2028 Goals
Communication Campaign	Fire season wildfire safety communications with video, social, media, and various other methods of communications. Email campaigns for customers along with a customer survey.	Fire season wildfire safety communications with video, social, media, and various other methods of communications. Email campaigns for customers along with a customer survey.	Fire season wildfire safety communications with video, social, media, and various other methods of communications. Email campaigns for customers along with a customer survey.	Fire season wildfire safety communications with video, social, media, and various other methods of communications. Email campaigns for customers along with a customer survey.	Fire season wildfire safety communications with video, social, media, and various other methods of communications. Email campaigns for customers along with a customer survey.	Fire season wildfire safety communications with video, social, media, and various other methods of communications. Email campaigns for customers along with a customer survey.
Industry Collaboration						

	2023 Goals	2024 Goals	2025 Goals	2026 Goals	2027 Goals	2028 Goals
EPRI Climate READi	Evaluate data availability, suitability and localizing climate information Identify climate hazards and data required for various applications Understand and document best practice climate-related data, application, and climate trends	Define common set of climate data to assess asset vulnerability both at component and grid level Guideline for applying climate trends and projections when selecting, specifying, designing, and installing new assets, as well as maintaining existing assets	Develop cost-benefit analysis, risk mitigation and adaptation strategies Establish framework and guidance for best approach in prioritizing investments and grid hardening technologies			
IWRMC Membership	Active participations in IWRMC (maturity survey, meetings, etc.)	Active participations in IWRMC (maturity survey, meetings, etc.)	Active participations in IWRMC (maturity survey, meetings, etc.)	Active participations in IWRMC (maturity survey, meetings, etc.)	Active participations in IWRMC (maturity survey, meetings, etc.)	Active participations in IWRMC (maturity survey, meetings, etc.)
Plan Monitoring & Implementation						
Wildfire Mitigation Program Delivery	Wildfire mitigation program delivery developing and ensuring compliance with the wildfire mitigation plan.	Wildfire mitigation program delivery developing and ensuring compliance with the wildfire mitigation plan.	Wildfire mitigation program delivery developing and ensuring compliance with the wildfire mitigation plan.	Wildfire mitigation program delivery developing and ensuring compliance with the wildfire mitigation plan.	Wildfire mitigation program delivery developing and ensuring compliance with the wildfire mitigation plan.	Wildfire mitigation program delivery developing and ensuring compliance with the wildfire mitigation plan.
Grant Opportunities	Resources to write grant application tied to funding wildfire mitigation initiatives	Resources to write grant application tied to funding wildfire mitigation initiatives				

APPENDIX G – PUBLIC SAFETY PARTNER EVENT REGISTRY TEMPLATE

The table below provides a sample template that will be used to track engagement with public safety partners in 2024.

Partner Name	Partner Type	Location	Date	Meeting Title	Meeting Topic	Feedback	Action Items	Due Date	Participants

APPENDIX H – ENGAGEMENT CAMPAIGN PERFORMANCE

The table below provides an overview of Pacific Power's engagement campaign performance. The metrics included are indicators for the effectiveness of customer engagement campaigns, but they are not definitive and may be heavily influenced by factors outside the control of the company's corporate communications group and/ or its consultants. For example, customers who have been directly impacted by PSPS may have a higher level of engagement in PSPS messaging and thus be more likely to complete a PSPS video. Therefore, these metrics are combined with other considerations, like customer feedback gathered from the bi-annual customer surveys, professional judgment, and input from external consultants, for engagement campaign decision-making.

Metric	Definition	Success Criteria	Reason for Metric	Results/ Discussion	Considerations for Future
Digital Display Ads - Grid Hardening					
Impressions	The number of times an ad has been served.	Growth in impressions	Helps gauge total reach.	The number of impressions for grid hardening messaging was low in comparison to other topics, indicating lower customer reach related to the topic.	Place emphasis on other topics (e.g., data science, PSPS) in the next year's ad campaign to encourage customer engagement.
Click Through Rate	Number of people who clicked/ number of people who are served an ad, expressed as a percentage.	Industry average	Identifies how well customers are engaging with messaging.	The click through rate for grid hardening messaging was high in comparison to the industry average, indicating a higher level of engagement among customers reached.	Continue grid hardening messaging, but consider using other communications mediums (e.g., social media).
Over The Top (Video) Advertising - Preparedness, PSPS					
Impressions	The number of times an ad has been served.	Growth in impressions	Helps gauge total reach.	The number of impressions for Pacific Power's video advertising on the topic of leadership was high, indicating that overall reach to customers was effective.	Continue messaging on Pacific Power's leadership and resilience regarding wildfire.
Video Completion Rate	The percentage of ad plays that were viewed through completion.	Prior year's VCR for a category of vi deo messaging	Identifies how well customers are engaging with messaging.	The click through rate for video advertising on the topic of leadership was low, indicating that customers had lower engagement with the messaging.	Target video advertising on topics that are of greater interest to customers.
Digital Audio (Radio) Advertising - Public Safety Power Shutoff					
Impressions	The number of times an ad has been served	Growth in impressions	Helps gauge total reach	The number of impressions for Pacific Power's audio advertising on PSPS was high, which indicates that the overall reach to customers was successful.	Consider putting PSPS messaging into another medium, like email messaging specific to the topic.
Click Through Rate	Number of people who clicked/ number of people who are served an ad, expressed as a percentage	Growth in CTR	Identifies how well customers are engaging with messaging	The click through rate for audio advertising on the topic of PSPS was low, indicating that customers had lower engagement with the messaging.	Consider putting PSPS messaging into another medium, like email messaging specific to the topic.
Customer Email - Wildfire Season Preparedness					

Metric	Definition	Success Criteria	Reason for Metric	Results/ Discussion	Considerations for Future
Number Sent	Total number of emails sent	Customer feedback	Identifies the number of customers receiving the message on widely preferred channel	Customer recall on email messaging remained high relative to other communications mediums (e.g., community meetings or events).	Consider a targeted push on specific wildfire preparedness topics like PSPS mitigation programs.