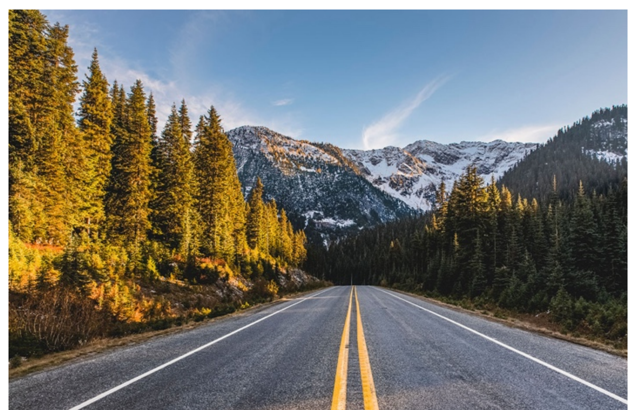
CWE STRATEGIES
CLIMATE, WILDFIRE & ENERGY RESILIENCE

IDAHO POWER WILDFIRE MITIGATION PLAN

2024 Independent Evaluator's Report

Draft



May 15, 2024

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DISCLAIMER

THE CONTENTS OF THIS REPORT REFLECT THE RESULTS OF CLIMATE, WILDFIRE AND ENERGY STRATEGIES, LLC'S ("CWE Strategies") INDEPENDENT REVIEW OF INVESTOR-OWNED ELECTRIC UTILITY WILDFIRE PROTECTION PLANS BASED ON THE INFORMATION AND MATERIALS DISCLOSED IN EACH PLAN AND THE ACTIVITIES BY THE UTILITY PROVIDER AS OF THE DATE OF THIS REPORT.

This Report summarizes findings and conclusions with respect to review and observation of the Utility Provider. In conducting the assessment, CWE Strategies has relied upon the Wildfire Protection Plan, information, documents, and other disclosures made available to it, over the course of CWE Strategies' review. CWE Strategies' summary does not address matters beyond those identified in the Statement of Work except to the extent that they are implicated in CWE Strategies' findings and are required as a matter of completeness or to provide context for CWE Strategies' conclusions. At all times CWE Strategies has conducted its review in accordance with the guidance and instructions provided to CWE Strategies with respect to the appropriate scope of review and resources allocated to the assessment. As such, this Report does not and is not intended to address all matters, subjects, or issues which may be relevant to the Utility Provider or the Oregon Public Utility Commission's (OPUC) investigation. The report is intended to serve only as a guide to assist with achieving compliance with regulatory requirements instituted by the OPUC for an independent evaluation of Investor-Owned Utility providers Wildfire Mitigation Practices.

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1. INTRODUCTION & KEY FINDINGS

This report presents Climate, Wildfire, and Energy Strategies, LLC's (CWE Strategies or IE) independent assessment of the Wildfire Mitigation Plan (WMP or Plan) submitted by Idaho Power on December 29, 2023. According to the assessment methodology described herein, the IE finds that Idaho Power has met 7 requirements, partially met 4 requirements, and failed to meet 0 requirements out of 11 total requirements set forth in Oregon Administrative Rules (OAR) Chapter 860, Division 300, Section 20 (WMP Rules). Of the 11 requirements, the IE finds that Idaho Power's Plan is likely effective in 1 area and is potentially ineffective and/or improvement needed in 10 areas.

On balance, the IE finds that all WMPs lack the data necessary to independently assess each utility's understanding of its risk (including a risk-ranked output of circuits/segments/spans from its risk model), the calculated risk reduction from various mitigations, including an alternatives analysis, and a clear understanding of the risk buy-down for the expenditures proposed in its Plan. The IE finds that a data-driven approach to WMPs is essential to make such determinations and recommends that utilities submit future WMPs containing model and data outputs that can be independently analyzed.

The IE further recommends that WMPs become standardized across utilities to facilitate analysis and assessment of compliance with the OARs. Standardization is necessary to minimize differences in interpretation of regulations and resulting variations in WMPs, as is apparent in the instant WMP filings. Many of the IE's recommendations would likely require dedicated working groups or another appropriate collaborative mechanism to fully implement this recommendation and ensure the shared understanding of parameters, metrics, etc. Understanding risk on the system is critical to ensure effective mitigations are selected under any utility wildfire mitigation plan, and risk modeling is only as strong as the underlying data input into the models and the validity of model assumptions.

1.1. Background & Scope of Review

Pursuant to Senate Bill 762 (2021) and Oregon Administrative Rules (OAR) Chapter 860, Division 300 – Wildfire Mitigation Plans, utilities in Oregon, by December 31st each year, must submit annual WMPs adhering to the requirements set forth in OAR 860-300-0020 as expanded upon in OAR 860-300-0030 (Risk Analysis), OAR 860-300-0040 (Wildfire Mitigation Plan Engagement Strategies), 860-300-0050 (Communication Requirements Prior, During, and After a Public Safety Power Shutoff (PSPS)), OAR 860-300-0060 (Ongoing Informational Requirements for Public Safety Power Shutoffs (PSPS)), OAR 860-300-0070 (Reporting Requirements for Public Safety Power Shutoffs (PSPS)), and OAR 860-300-0080.

The Oregon Public Utility Commission (OPUC) retained the services of CWE Strategies, LLC to provide an independent evaluation of the WMPs submitted by the following investor-owned utilities (IOU or utility):

- PacifiCorp, dba Pacific Power – Docket Number: UM 2207
- Portland General Electric Company – Docket Number: UM 2208
- Idaho Power Company – Docket Number: UM 2209

OPUC tasked the IE with assessing utility compliance with the provisions of OAR 860-300-0020 as described in detail in the Scope of Work.

1.2. Evaluation Methodology & Maturity Rubric

The IE undertook a 2-step evaluation process to assess WMPs. First, the IE assessed general compliance to the regulations. The IE then assessed WMPs for likely effectiveness, as described below. A summary of the IE's findings is contained in Appendices A, B, and C to this report.

1.2.1. Compliance with OAR 860-300-0020 et seq.

The IE first evaluated each utility's WMP and supplemental information request responses to determine if the utility submitted sufficient information to comply with OAR 860-300-0020 and its related requirements. The IE assigned one of three possible outcomes to each of the 11 requirements and sub-requirements set forth in OAR 860-300-0020.

(1) **Met:** The utility has, on balance, provided sufficient information in its WMP, including information requested by OPUC in the previous year's order, such that an evaluator can determine that the utility has met the identified requirement(s).

(2) **Partially Met:** The utility has, on balance, provided some, but not all information in its WMP, including information requested by OPUC in the previous year's order, necessary for an evaluator to determine that the utility has met the identified requirement(s).

(3) **Not Met:** The utility has, on balance, provided no information or insufficient information in its WMP, including information requested by OPUC in the previous year's order, for the evaluator to determine that the utility has met the identified requirement(s).

Table 1. *OAR 860-300-0020 Requirements*

OAR Section	Requirement(s)
OAR 860-300-0020 (1)(a)(A)+(B)	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.
OAR 860-300-0020 (1)(b)	Identified means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk.
OAR 860-300-0020 (1)(c)	Identified preventative actions and programs that the utility will carry out to minimize the risk of the utility's facilities causing wildfire.
OAR 860-300-0020 (1)(d)	Discussion of the 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.
OAR 860-300-0020 (1)(e)	Identified protocol for the de-energization of power lines and adjusting of power system operation 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 860-300-040 through 860-300-0050.
OAR 860-300-0020 (1)(f)	Identification of the community outreach and public awareness efforts that the utility will use before, during, and after a wildfire season, consistent with OAR 860-300-040 through 860-300-050.
OAR 860-300-0020 (1)(g)	Description of the procedures, standards, and timeframes the Public Utility will use to inspect utility infrastructure in areas it has identified as heightened risk of wildfire, consistent with OAR 860-024-0018.
OAR 860-300-0020 (1)(h)	Description of the procedures, standards, and timeframes that the utility will use to carry out vegetation management in areas it has identified as heightened risk of wildfire, consistent with OAR 860-024-0018.
OAR 860-300-0020 (1)(i)	Identification of the development, implementation, and administrative costs for the Plan, which includes discussion of risk-based cost and benefit analysis as well as considerations of technologies that offer co-benefits to the utility's system.
OAR 860-300-0020 (1)(j)	Description of participation in national and international forums, including workshops identified in section 2, chapter 592, Oregon Law 2021, as well as research and analysis the utility has undertaken to maintain expertise in leading-edge technologies and operational practices, including how such

	technologies and operational practices have been used to develop and implement cost effective wildfire mitigation solutions.
OAR 860-300-0020 (1)(k)	Description of ignition inspection programs, as described in Division 24 of these rules, including how the utility will determine and instruct its inspectors to determine conditions that could pose an ignition risk on its own equipment and pole attachments.

1.2.2. WMP Effectiveness

It is reasonable to assume that the purpose of developing a WMP is for the utility to demonstrate an effective pathway for reducing wildfire risk on its system balanced against costs.[1] As such, it is also reasonable to assess the Plan not only as to whether each area of the regulations is addressed but also as to whether the Plan, if implemented, can be understood to reduce risk over the Plan period. The IE therefore evaluated Plan components against the following criteria for overall Plan effectiveness: 1) the utility sufficiently demonstrates that it understands the risk (likelihood and consequence) of a wildfire caused by its equipment as well as the risk present to its equipment in the case of wildfire caused by external sources; (2) the utility sufficiently demonstrates a risk-based approach to selecting mitigations; (3) the utility sufficiently demonstrates a clear process for selecting mitigations and plans for safely deploying mitigations, especially in the case of PSPS; and (4) the utility sufficiently presents mitigation costs and a clear methodology for demonstrating risk reduction benefits against costs.[2]

The IE assigned one of two possible outcomes recognizing that utilities' wildfire mitigation planning should be an ever evolving and maturing effort:

(1) **Likely Effective**: The utility has provided sufficient information to demonstrate likely Plan effectiveness, although recommendations for improvement may be provided.
(2) **Potentially Ineffective/Improvement Needed**: The utility failed to provide sufficient information to demonstrate Plan effectiveness and/or the information provided raises concerns as to the Plan's effectiveness in reducing wildfire risk on the system.

A finding that a Plan section is sufficiently effective is not a guarantee of the utility's performance under the Plan, which is the sole responsibility of the utility.

[1] See ORS 757.963(1). "The public utility must design the plan in a manner that seeks to protect public safety, reduce risk to utility customers and promote electrical system resilience to wildfire damage." See also SB 762.3 (2)(B)(b), which states that utilities must "identify a means for mitigation wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk."
[2] The IE recommends that future WMP evaluation processes contain an up-front standard of review. One such standard that could be applied is set forth in Section 5 of the Office of Energy Infrastructure Safety's 2023-2025 Wildfire Mitigation Plan Process and Evaluation Guidelines in conducting its review. (See 2023-2025 Process and Evaluation Guidelines dated 12/7/2022, accessed on April 9, 2024 at https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2023-wildfire-mitigation-plans/). Elements include assessment of completeness, technical and programmatic feasibility and effectiveness, resource use efficiency, demonstrated year-over-year progress, forward-looking growth, performance metrics, and targets.

1.2.3. Maturity Rubric

The OPUC[3] tasked the IE with developing a maturity rubric and scoring the utility against that rubric. As discussed further in Section 4, the IE recommends the utilities deploy the International Wildfire Risk Mitigation Consortium maturity model and report maturity levels against that rubric in future WMP filings. For WMP requirements listed in OAR 860-300-0020, the IE in some cases offers recommendations for actions the utility could take to improve its maturity in the coming year (or other designated timeframe). Each recommendation is assigned a unique ID (e.g. IE_IP_01).

However, as detailed in this report, the IE finds that, on balance, the WMPs submitted by the Oregon utilities lack the level of data and standardization necessary to adequately ascertain the risk profile and risk reduction potential of the Plan, as would be expected given the number of years WMP requirements has been in place in Oregon. Further, all plans lack a robust alternatives analysis and cost/benefit analysis to ascertain the prudence of investments. As discussed below, the IE offers multiple cross-utility recommendations to raise overall Plan maturity to what is reasonable to independently evaluate each utility's understanding of risk on the system and the associated risk buy-down from selected mitigations. Cross-utility recommendations are also assigned unique IDs (e.g. IE_ALL_01).

2. OVERVIEW OF UTILITY SERVICE TERRITORY

Idaho Power's service area covers approximately 24,000 square miles, with approximately 4,745 square miles in Oregon. The utility serves approximately 20,000 customers in Oregon and 600,000 in Idaho. Idaho Power has 24,186 total pole miles with 12 percent of those miles in Oregon. Idaho Power differentiates its high fire risk zones (HFRZs) by tiers, with Yellow Risk Zones (YRZ or Tier 2) and Red Risk Zones (RRZ or Tier 3). In 2024 in Oregon, Idaho Power added 3 new YRZs and 1 new RRZ; the new RRZ is in Oregon. Idaho Power states that it has 23.6 transmission pole miles (0.5 percent of all transmission lines) in YRZs in Oregon and 41.3 distribution pole miles (0.2 percent of all distribution lines) in YRZs in Oregon. Zero transmission pole miles are in RRZs in Oregon and 40 distribution total pole miles (0.2 percent) are in RRZs.

[3] OPUC Commission Orders have recognized that wildfire mitigation plans would require evolution from their initial states.

3. IE ASSESSMENT OF IDAHO POWER'S COMPLIANCE TO OAR 860-300-0020, PLAN EFFECTIVENESS & ASSOCIATED RECOMMENDATIONS

The following sections present the IE's assessment of Idaho Power's compliance with the requirements set forth in OAR 860-300-0020 and its evaluation of Plan effectiveness. The results and associated recommendations are summarized in tabular format in the appendices to this report.

3.1. OAR 860-300-0020 (1)(a)(A)+(B)

This section of the OAR requires the utility to identify areas within and outside the service territory (but within the right-of-way for generation and transmission assets) that are subject to heighted wildfire risk, including determinations for such conclusions. The IE interprets this portion of the OAR to refer to the means the utility uses to identify areas subject to heightened wildfire risk if an ignition occurs (wildfire consequence), which each utility identifies with differing nomenclature. For the purposes of this evaluation, the IE refers to these as HFRZs.

The IE interprets this portion of the OAR to be independent of the utility's understanding of the likelihood of any utility asset sparking an ignition or potential damage to utility assets caused by a wildfire, which appears to be covered more fully under OAR 860-300-0020(1)(b). The IE also understands determinations of HFRZs to be more static in nature and independent of more temporal components, such as a daily fire potential index. The IE interprets HFRZs to represent the base of a risk triangle on top of which all other risk would be overlayed. However, later in this report, the IE recognizes that this interpretation differs across utilities and therefore presents cross-utility recommendations regarding the need for standardization of terminology and shared understanding of the purpose of HFRZ designations.

3.1.1. Compliance with the OAR

The IE finds that Idaho Power has **met** the requirements of this section of the OAR.

Although the IE lacks the data to independently verify the weighting of the various components Idaho Power deploys in making its HFRZ determinations, the IE finds that Idaho Power describes elements considered in making its determination of HFRZs, including elements of fire probability and consequence, such as historical weather, topography, fuel types present, fuel moisture content, and structures present on the landscape. Further, Idaho Power validates its results with local fire authorities; although, Idaho Power has not described how it weights that feedback. Idaho Power updated multiple parts of its model in 2023, including working towards incorporating more granular climatology, updating structural data to better capture growth in the wildland-urban interface (WUI), developing a more granular understanding of vegetation, incorporating disturbances such as burn scars, and modeling fire spread to 12 hours.

3.1.2. Effectiveness

The IE finds that Idaho Power's response to this portion of the OAR is **likely effective**; however, the IE offers recommendations for improvement.

The IE is concerned about the significant differences in understanding and application of this portion of the OAR across utilities and makes associated recommendations in the Cross-Utility Recommendations sections below. However, on balance, the IE finds that Idaho Power is including logical components in its HFRZ determination. However, the IE cannot independently verify the weighting of the various elements included in the HFRZ calculation nor can it verify the natural breaks used to differentiate between YRZs and RRZs.

3.1.3. Recommendations

In addition to the cross-utility recommendations set forth later in this document, the IE recommends:

IE_IP_01. Idaho Power should explain why it chose a 240-meter limit for its HFRZ and explain how it models risk to its assets from outside sources.

IE_IP_02. Idaho Power should report the breaks used to differentiate between YRZs and RRZs, including individual metrics, and how, in totality, the differentiation is delineated.

IE_IP_03. Idaho Power should explain how it incorporates vegetation grow-back in burn scars into its HFRZ determinations.

IE_IP_04. Idaho Power should clarify if areas with undergrounded resources are determined to be ineligible for inclusion in its HFRZ determinations or if undergrounding is only considered as an element in non-HFRZ areas.

3.2. OAR 860-300-0020 (1)(b) and 1(i)

OAR 860-300-0020(1)(b) requires the utility to identify means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting wildfire risk reduction, and OAR 860-300-0020(1)(i) requires the utility to identify the development, implementation, and administrative costs of the Plan, including discussion of a risk-based cost and benefit analysis of technologies that offer co-benefits to the utility's system. In this section, the IE does not evaluate specific mitigations; mitigations are evaluated under OAR 860-300-0020(1)(c).

The IE considers these two regulation sections together because they both appear to require elements of weighing risk against mitigation costs. The IE considers the utility's assessment of both the likelihood of an ignition being caused by its equipment and the consequence of that ignition, including elements such as ingress/egress, social vulnerability, fire suppression capabilities, etc. The IE notes that its assessment is conducted under a different OAR section than that of last year's IE[4] and points to its cross-utility recommendation to create a standardized template and definitions to alleviate differences in interpretations of the OAR that hinder ability to conduct cross-utility comparisons.

3.2.1. Compliance with the OARs

The IE evaluates OAR 860-300-0020(1)(b) by assessing whether the utility supplies the necessary information to demonstrate its understanding of its risk and an explanation of how it selects mitigations by determining risk buy-down against costs. The IE examines the utility's compliance with OAR 860-300-0030, which articulates elements and criteria for utility risk analysis, as part of its assessment of OAR 860-300-0020 (1)(b). However, the IE reserves the bulk of its evaluation of the utility's presentation of overall Plan costs and cost-benefit ratios (or the equivalent) in its assessment of responses to OAR 860-300-0020(i) as well as evaluation of co-benefits.

3.2.1.1. OAR 860-300-0020 (1)(b)

The IE finds that Idaho Power has **partially met** the requirements of this section of the OAR.

Idaho Power describes its overall risk framework and explains the steps it is taking to better understand risk on the system. The utility has developed its understanding of risk drivers and impacts and has constructed a bow-tie risk framework. Idaho Power explains how it intends to use probabilistic modeling (Monte Carlo simulations) to produce a distribution of outcomes.

However, the detail provided by Idaho Power is lacking such that it is not clear if/how Idaho Power's model results in circuit-level (or some other level of granularity) risk rankings or if it accounts for risk impacts from deploying mitigations. It is also unclear if Idaho Power uses multiple models and methodologies (the IE believes it does) and how those fit together to yield Idaho Power's understanding of its risk and its decisions to pursue one mitigation over another. Finally, it appears that Idaho Power is relying on probabilistic modeling to draw conclusions about potential future ignitions, but it is not clear how much historical outage data Idaho Power has collected to input as a proxy for ignitions when developing its risk model. More information is necessary to understand if Idaho Power has fully met the requirements of the OAR, much of which is set forth in the IE's cross-utility recommendations.

3.2.1.2. OAR 860-300-0020 (1)(i)

The IE finds that Idaho Power has **partially met** the requirements of this section of the OAR. The IE finds that Idaho Power **has not met** the requirements pertaining to a risk-based cost and benefit analysis but has **met** all other elements.

[4] *See* Independent Evaluator Report on Wildfire Mitigation Plan Compliance, Bureau Veritas, Docket No. UM 2207, UM 2208, UM 2209, Subject Areas 2 and 9, June 6, 2023.

Idaho Power provides projected cost information for its operations and maintenance (O&M) and capital expenditures over the five-year Plan period, with expenditures broken down to a reasonable level; however, it does not appear to detail Plan administrative costs (although it does reference weather forecasting personnel). Additionally, Idaho Power does not provide a clear breakdown of its cost-benefit rankings, and states that it is developing a methodology. While a methodology may be in development, the IE cannot glean whether Idaho Power is currently relying on a more detailed methodology other than comparing mitigation costs to potential costs if a wildfire were to occur. Given that automatic cost recovery is directly tied to implementation of the WMP, a higher level of detail is warranted to satisfy the requirements of the regulation. Idaho Power does present a table of wildfire mitigation co-benefits, including safety, reliability, and resilience; thus, Idaho Power at the highest level has considered co-benefits.

3.2.2. Effectiveness

3.2.2.1. OAR 860-300-0020 (1)(b), inclusive of OAR 860-300-0030.

The IE finds that Idaho Power's response to this portion of the OAR is **potentially ineffective/improvement needed**.

As described in greater detail in cross-utility recommendations, the IE is concerned about the lack of consistency and visibility into model inputs and outputs, the development of cost-benefit analyses, and the failure to include PSPS as a risk driver in utility wildfire risk modeling efforts. While the IE provides cross-utility recommendations elsewhere, these elements do factor into its assessment of Idaho Power's Plan effectiveness.

For example, Idaho Power does not demonstrate that it has a comprehensive and up-to-date asset registry. In addition, Idaho Power does not satisfactorily demonstrate how it incorporates, including weighting, its outage and ignition history into its risk model nor how (or if) it incorporates risk reductions from mitigations into the model. Further, Idaho Power does not report the percentage of each of its primary ignition drivers nor does it present model output showing overall risk rankings of its circuits. These are examples of data and information omissions that make it difficult for the IE to have satisfactory visibility into Idaho Power's risk model and hinders its ability to assess where Idaho Power is applying its mitigations to ensure that the utility is deploying the bulk of its mitigations over the Plan period to the areas of highest risk.

3.2.2.2. OAR 860-300-0020 (1)(i)

The IE finds that Idaho Power's response to this portion of the OAR is **potentially ineffective/improvement needed**.

Idaho Power's cost-benefit methodology is lacking. As stated above, Idaho Power relies on the presumed cost of wildfires in other states and draws the bold conclusion that WMP benefits exceed wildfire costs. While Idaho Power details its expenditures in a more granular manner than Portland General Electric, there is no mitigation risk buy-down comparison to evaluate the benefits of Idaho Power's strategy. Like other utilities, Idaho Power allocates the bulk of its operations and maintenance (O&M) budget on vegetation management (84 percent). This expenditure represents 62 percent of its entire combined WMP O&M and capital expenditures budget. Absent the ability to evaluate the risks reduced and the perceived benefits of the mitigations, the IE is left blind as to whether Idaho Power is selecting the appropriate mix of mitigations to address its wildfire risk.

The IE discusses assessment of co-benefits in the cross-utility recommendation section of this report.

3.2.3. Recommendations

In addition to the cross-utility recommendations, the IE recommends the following:

IE_IP_05. Idaho Power should provide a schematic of all models used to determine risk and how those models work together to produce a risk-ranked output of utility circuits (or some other appropriate level of granularity).

IE_IP_06. Idaho Power should provide a table with key risk drivers that includes weighting of those drivers, and detail the methodology used to determine key risk drivers. Idaho Power should explain how it is incorporating less frequent and extreme events into its risk modeling process to ensure proper understanding of risk.

IE_IP_07. Idaho Power should explain the temporal period for outage and ignition history used in risk modeling and explain how these two factors are considered in the overall risk methodology.

IE_IP_08. Idaho Power should demonstrate a methodology for determining the cost-benefit ratio (or risk spend efficiency ratio) for its planned expenditures. Idaho Power should be able to demonstrate the risk buy-down from deployment of selected mitigations.

3.3. OAR 860-300-0020 (1)(c)

OAR 860-300-0020(1)(c) requires the utilities to identify preventive actions and programs they will utilize to minimize the risk of utility facilities causing a wildfire. Here, the IE evaluates the various mitigation programs deployed by the utilities, including situational awareness, vegetation management, grid operations, and grid hardening. Assessment of inspection programs, PSPS deployment, and vegetation management are discussed in corresponding sections of the OAR elsewhere in this report; however, they are included as part of the IE's overall assessment under this portion of the OAR.

3.3.1. Compliance with the OAR

The IE finds that Idaho Power has **met** the requirements of this section of the OAR.

Idaho Power provides information on various selected mitigations, including developing a situational awareness capability, deploying vegetation management, and implementing limited operational capabilities and system hardening. Idaho Power describes the various technologies it is piloting, including wildfire detection cameras and covered conductor. Idaho Power states that it revised its transmission construction standards to utilize steel poles and structures for new line construction built to 138kV and above in the HFRZ. Idaho Power does not report any undergrounding in Oregon as part of its capital expenditures, and it emphasizes transmission and distribution inspection programs as a key element of its mitigation strategy. Idaho Power's current operational strategy involves opening reclosers during the HFRZs during red fire potential index (FPI) conditions. Idaho Power does not list firm commitments for most of its mitigation initiatives.

3.3.2. Effectiveness

The IE finds that Idaho Power's response to this portion of the OAR is **potentially ineffective/improvement needed**.

Idaho Power is exploring or deploying many of the mitigations found to be effective by utilities that are further along in their wildfire mitigation practices; however, absent an independent assessment of risk, transparency into the forecasted risk buy-down and knowledge of where work is occurring (showing that work is occurring in a manner to buy down risk on the riskiest circuits), the IE cannot draw conclusions into the overall effectiveness of Idaho Power's Plan. It is possible that Idaho Power's mitigation strategy is appropriate to the risk on its system, which may be different that of other utilities in Oregon; however, the IE cannot independently make that determination.

Nevertheless, Idaho Power's mitigation strategy appears to be at an early stage. It has developed a Fire Potential Index and appears to be planning to install wildfire detection cameras; however, it has not discussed the granularity of its weather data or if additional weather stations are needed. Idaho Power relies heavily on its inspection program but does not address how inspection findings yield mitigation strategies. In discussing its covered conductor pilot, Idaho Power does not address when it will determine whether to proceed with installation of covered conductor in its service territory nor does it address barriers to its implementation if it is a selected mitigation (i.e. how pole loading pilots and pole replacement programs fit into a covered conductor deployment strategy). It also appears that Idaho Power is focusing the bulk of its reconductoring on transmission versus distribution lines. The IE is concerned that Idaho Power's approach is heavily weighted towards vegetation management, despite other utilities reducing and refining reliance on this mitigation as they mature. The IE does commend Idaho Power's approach to partnerships to address fuel loads and appreciates that it reports out on its internal wildfire team capacity as a measure of maturity.

3.3.3. Recommendations

In addition to the cross-utility recommendations, especially those regarding risk ranking and risk buy-down, the IE recommends the following:

IE_IP_09. Idaho Power should justify its focus on transmission versus distribution hardening/reconductoring by demonstrating that transmission risk is the highest risk on its system.

IE_IP_10. Idaho Power should report out on the results of its covered conductor study and discuss barriers to implementation. Idaho Power should offer covered conductor commitments if it intends to pursue this mitigation.

IE_IP_11. Idaho Power should demonstrate that its reliance on vegetation management is a prudent approach by providing an alternatives or co-mitigation analysis for its riskiest circuits.

3.4. OAR 860-300-0020 (1)(d)

OAR 860-300-0020(1)(d) requires utilities to discuss PSPS and operational settings outreach and communication strategy to regional, state, and local entities. The IE in this section focuses solely on Public Safety Partner (PSP) coordination and preparedness.

3.4.1. Compliance with the OAR

The IE finds that Idaho Power has **met** the requirements of this section of the OAR.

Idaho Power describes its outreach and communications strategy with PSPs at the highest level. Communications appear to focus heavily on preparation; however, it is unclear how Idaho Power coordinates with PSPs during events (wildfires or PSPS). It is also unclear how Idaho Power determines its PSPs; although, Idaho Power states that it is a member of emergency planning committees in counties where they are active. Idaho Power notes that it has an active database for PSP contacts and that it documents communication preferences. Idaho Power discusses feedback received from PSPs, but feedback reported in the WMP is limited.

3.4.2. Effectiveness

The IE finds that Idaho Power's response to this portion of the OAR is **potentially ineffective/improvement needed**.

It is unclear if Idaho Power is actively engaging and working with the incident command system (ICS) framework, that it has adequately trained employees to work within that framework, or that it has a robust plan in place to facilitate coordination with PSPs during events. It is also unclear if Idaho Power communicates changes in operational settings to PSPs (including critical facilities). Idaho Power does not justify its cadence of once per year meetings with PSPs nor does it provide a clear picture of which entities it identifies as a PSP. With limited PSP feedback, the IE is left to wonder how Idaho Power went about soliciting feedback and from whom.

3.4.3. Recommendations

In addition to cross-utility recommendations, the IE recommends the following:

IE_IP_12. Idaho Power should explain if its holds tabletop exercises with PSPs to prepare for wildfire season, and if so, with whom and at what frequency.

IE_IP_13. Idaho Power should report on whether it has primary and secondary 24-hour points of contact for all PSPs and its cadence and process for ensuring information is up to date.

IE_IP_14. Idaho Power should explain in what forums, from whom, and how it solicited PSP feedback and describe how Idaho Power implemented the PSP feedback received in 2023 and any additional feedback received in 2024.

IE_IP_15. Idaho Power should explain if it operates within the ICS framework and if employees are trained in ICS (and if so, how many employees and what level of ICS training has been received).

3.5. OAR 860-300-0020(e)

OAR 860-300-0020(e) requires utilities to describe a de-energization (PSPS) protocol, including a communication strategy consistent with OAR 860-300-0040 and OAR 860-300-0050.

3.5.1. Compliance with the OAR

The IE finds that Idaho Power has **met** the requirements of this section of the OAR.

Idaho Power presents its high-level internal PSPS playbook, which explains the various factors that Idaho Power considers in determining whether to call a PSPS event as well as the overarching responsibilities within the company and notification and communication timeframes, etc. Idaho Power describes its communication and outreach strategy, including educational outreach across multiple mediums. Idaho Power states that it works with PSPs to pre-determine the need for and locations of potential community resource centers (CRCs), and it states that it holds internal planning exercises. Idaho Power does not discuss its strategy to identify and communicate with vulnerable populations nor does it describe strategies to reduce the impact of PSPS on those populations.[5] Idaho Power also does not describe how it will modify its main webpage to make PSPS or wildfire information readily available during an event nor does it discuss outreach with community-based organizations (CBO) to facilitate PSPS preparation.

3.5.2. Effectiveness

The IE finds that Idaho Power's response to this portion of the OAR is **potentially ineffective/improvement needed**.

[5] Idaho Power does allude to an understanding that PSPS may be less likely to be needed in their service territory given usual weather conditions (Page 82).

Idaho Power appears to have all the major components of a PSPS program, but the program appears to be designed at a high level and appears to lack the detailed information necessary to execute a successful PSPS event.[6] It is unclear if Idaho Power assembles its own emergency operations center (EOCs) during a PSPS event (or if Idaho Power employees embed into other EOCs). Given that Idaho Power has not called a PSPS event to date, the IE would like to see an after-exercise report on its internal and PSPS tabletop exercises to assess whether Idaho Power is prepared for an event if it were to occur.

The IE is also concerned about Idaho Power's outreach and engagement strategy, particularly for vulnerable and non-English or limited-English speaking populations. Idaho Power does not discuss if it has a strategy for identifying vulnerable (also known as access and functional needs (AFN)) populations or if it has a strategy for ensuring positive contact with AFN populations during an event. The IE also cannot glean whether Idaho Power has dedicated (and easily accessible) webpages for when an event is called, including how to locate CRCs, search functions for PSPS boundaries, and shapefiles for use by PSPs during an event.

3.5.3. Recommendations

In addition to cross-utility recommendations, the IE recommends the following:

IE_IP_16. Idaho Power should demonstrate how customers who speak languages other than English or have limited English proficiency can access information, both to prepare for a PSPS event and during a PSPS event. Idaho Power should explain its understanding of the prevalence of languages spoken, other than English, within its Oregon service territory.

IE_IP_17. Idaho Power should demonstrate how it will make PSPS real-time event information readily and easily accessible and available from its homepage during an event.

IE_IP_18. Idaho Power should demonstrate it if has conducted benchmarking to other utilities' experiences with calling PSPS events (including reviewing after action reports) to ensure that its program is fully developed should it need to call a PSPS event.

IE_IP_19. Idaho Power should explain how it identifies AFN customers prior to PSPS events and if it has a protocol for ensuring positive contact prior to a PSPS going into effect.

IE_IP_20. Idaho Power should explain how it is proactively identifying CBOs to assist in customer preparedness.

IE_IP_21. Idaho Power should justify the cadence of tabletop exercises with PSPs (and internally) and explain if it has solicited feedback on these exercises, and if so, what changes were made to its program.

[6] Idaho Power does not report on whether it has executed a PSPS event, but the IE assumes it has not.

3.6. OAR 860-300-0020(f)

OAR 860-300-0020(f) requires the utility to identify the community outreach and awareness efforts it will use before, during, and after wildfire season, consistent with OAR 860-300-0040 and OAR 860-300-0050.

3.6.1. Compliance with the OAR

The IE finds that Idaho Power has **met** the requirements of this section of the OAR.

Idaho Power describes its overall wildfire preparedness outreach and communication efforts presented in multiple languages and via various mediums, including print, ad, radio, social media, in-person events, and its webpage. Idaho Power focuses the timing of its outreach around and during wildfire season. Idaho Power presents a series of communications metrics and reports its performance to those metrics; although, for many of the metrics it is impossible to glean effectiveness.[7] Finally, Idaho Power discusses the results of a customer engagement survey on perceptions of risk and support for mitigation measures.

3.6.2. Effectiveness

The IE finds that Idaho Power's response to this portion of the OAR is **potentially ineffective/improvement needed**. Idaho Power's strategy contains the elements required by the regulations, and preliminary feedback appears to show a positive attitude among customers for Idaho Power's efforts. However, it is unclear if Idaho Power has conducted outreach in languages other than English or if it has conducted research to ascertain the customer's understanding of wildfire preparedness (and resources available to them). It is also unclear if Idaho Power has engaged with CBOs to aid in the dissemination of wildfire preparedness information.

3.6.3. Recommendations

In addition to cross-utility recommendations, the IE recommends the following: .

IE_IP_22. Idaho Power should demonstrate that is has made wildfire preparedness information available to customers who speak languages other than English. Idaho Power should also demonstrate if it has partnered with CBOs to further expand its outreach efforts, especially to AFN populations.

IE_IP_23. Idaho Power should explain if it has assessed customer awareness and understanding of the PSPS and wildfire planning outreach it has conducted, and if so, the results of that assessment.

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[7] Several metrics lack a target or metric of success against which to determine effectiveness.

3.7. OAR 860-300-0020(g)

OAR 860-300-0020(g) requires the utility to describe the procedures, standards, and timeframes it will use to inspect utility infrastructure within the HFRZ, consistent with OAR 860-024-0018. The IE differentiates this from the requirements in OAR-860-300-0020(k), which it interprets as addressing how the utility identifies ignition risk drivers and inspects for those drivers.

3.7.1. Compliance with the OAR

The IE finds that Idaho Power has **met** the requirements of this section of the OAR.

Idaho Power details its various transmission and distribution inspections, including ground, aerial, and infrared as well as conducting wood pole inspections. Defects are assigned a priority level (one, two, or three), and corrective action plans are scheduled and repaired consistent with OAR 560-024-0018. Idaho Power explains that as of 2023, it conducts annual ground-based and targeted infrared in Tier 3 HFRZ areas. Idaho Power states that it conducts quality control annually on a randomly selected sample of work, and findings are shared with field workers to foster learning. Idaho Power reports a greater than 95 percent passage rate for its pole inspection quality control assessments. Idaho Power also reports that it has only identified tree attachments within the non-HFRZ and, consistent with regulation, will remove those attachments prior to 2027.

3.7.2. Effectiveness

The IE finds that Idaho Power's response to this portion of the OAR is **potentially ineffective/improvement needed**.

Idaho Power clearly has a thoughtful and thorough inspection program; however, more information is needed for the IE to ascertain effectiveness. Idaho Power does not explain if or how it prioritizes defects within the timeframes for repair for each priority. For example, a defect classified as Priority 2 can be repaired anytime within a 2-year period; however, it is unclear if or how that defect is prioritized for repair if it is located on one of Idaho Power's highest risk-ranked circuits (or segments/zones). Idaho Power also does not explain the rationale for its use of a heightened inspection cadence and procedures for Tier 3 HFRZ areas, but not for Tier 2 areas. Idaho Power notes that Priority 2 defects that are not assigned a corrective plan within 24 months are reviewed by the transmission & distribution vegetation and maintenance engineering leader, but it does not report on the number of defects on which this occurs or how it addresses these defects; for example, if it reinspects and restarts the correction clock. Finally, Idaho Power does not report its quality control passage rate for assets other than poles. The IE addresses this last concern in the cross-utility recommendations.

3.7.3. Recommendations

In addition to cross-utility recommendations, the IE recommends the following:

IE_IP_24. Idaho Power should explain if it further prioritizes defects for repair beyond the Priority repair timelines based on circuit risk-rankings within the HFRZ.

IE_IP_25. Idaho Power should explain its rationale for only increasing the cadence of inspections in the Tier 3 HFRZ (RRZ), but not the Tier 2 HFRZ (YRZ).

IE_IP_26. Idaho Power should explain, with examples, how it analyzes inspection find trends to inform future inspection procedures.

3.8. OAR 860-300-0020(1)(h)

OAR 860-300-0020(1)(h) requires the utilities to describe the procedures, standards, and timeframes for carrying out its vegetation management program in the HFRZ, consistent with OAR 860-300-0018. Here, the IE focuses on the utility's inspection and remediation approaches, but the IE remains concerned with the scale and scope of Idaho Power's vegetation management program, which does not appear to be adequately justified.

3.8.1. Compliance with the OAR

The IE finds that Idaho Power has **met** the requirements of this section of the OAR.

Idaho Power describes its transmission and distribution vegetation management approach, which consists of pruning vegetation to certain specifications and conducting patrols/remediations across varying time scales (that differ for transmission and distribution). For Tier 3 HFRZ (but not Tier 2), Idaho Power conducts patrols on an annual basis and conducts quality control on all work. For transmission lines, cycle buster pruning is conducted on an 18-month basis, and 2 years after the cycle prune for distribution lines. Finally, Idaho Power undertakes pole clearing to twenty feet on 100 percent of transmission lines and an unreported quantity of distribution lines.

3.8.2. Effectiveness

The IE finds that Idaho Power's response to this portion of the OAR is **potentially ineffective/improvement needed**.

Although Idaho Power has met the required elements of the OAR section, absent the ability to review programmatic data, the IE is unable to determine the effectiveness of Idaho Power's vegetation management program. For example, Idaho Power does not explain its rationale for conducting enhanced vegetation management in Tier 3, but not Tier 2 HFRZs. In addition, Idaho Power does not explain how circuit risk is considered in assignment of work through the Terra Spectrum VM Suite. Idaho Power states that it conducts audits on 100 percent of work conducted in HFRZ Tier 3; however, it does not explain find rates and associated changes to vegetation practices. Further, Idaho Power does not explain if it analyzes quality control find rate differences among in-house versus contracted utility arborists, and if so, how those differences are addressed. Idaho Power does not report if its ignitions analyses have yielded insight into species-specific concerns and if any changes have been made to its program as a result. Finally, Idaho Power does not demonstrate how it ensures or measures consistency of application for its higher priority, medium hazard, and lower hazard designations in its distribution inspection program. Some of these issues, among others, are addressed in the cross-utility recommendation section of this report.

3.8.3. Recommendations

In addition to cross-utility recommendations, the IE recommends the following:

IE_IP_27. Idaho Power should explain the rationale behind its determination to conduct increased patrols/pruning in Tier 3 HFRZs (RRZ), but not Tier 2 HFRZs (YRZ).

IE_IP_28. Idaho Power should explain if vegetation work is further prioritized based on circuit (or another more granular measure) risk.

IE_IP_29. Idaho Power should explain if areas requiring extensive remediation are evaluated for alternative non-vegetation mitigations, and if so, the thresholds that are considered in pursuing non-vegetation alternatives.

IE_IP_30. Idaho Power should demonstrate how vegetation inspection findings are integrated into future inspection protocols. In addition, Idaho Power should report its quality control find rates as well as if there are differences in find rates between in-house versus contracted quality control.

IE_IP_31. Idaho Power should provide its rationale for conducting pole clearing on distribution poles (e.g. how poles are selected). Idaho Power should explain if replacement of certain equipment on poles reduces or eliminates the need for pole clearing.

3.9. OAR 860-300-0020(1)(j)

OAR 860-300-0020(1)(j) requires the utility to describe its participation in national and international forums as well as research and analysis the utility has undertaken to maintain expertise in leading-edge technologies and operational practices. The utility must also detail how it has used emerging technologies and operational practices to develop and implement cost-effective wildfire mitigation solutions.

3.9.1. Compliance with the OAR

The IE finds that Idaho Power has **partially met** the requirements of this section of the OAR.

Idaho Power lists its participation in multiple forums, both national and international, and discusses one academic partnership. For example, Idaho Power explains that it partners with Federal, State, and local government agencies in Southern Idaho to identify areas of collective concern and discuss risk mitigation strategies. Idaho Power also discusses at length its engagement with peer utilities, including joining the International Wildfire Risk Mitigation Consortium (IWRMC). In addition to participation in forums, Idaho Power identifies several pilots, including wildfire detection cameras, covered conductor, cross-boundary fuels reduction collaboration, pole loading, situational awareness, and seasonal Enhanced Protection Settings

(EPS). However, aside from a discussion on wildfire cameras, Idaho Power does not detail or explain changes anticipated to be made or pilots implemented resulting from its collaborations/attendance/participation in forums. Idaho Power also does not explain how the emerging technologies and operational practices are being considered to develop cost-effective mitigation solutions.

3.9.2. Efficiency

The IE finds that Idaho Power's response to this portion of the OAR is **potentially ineffective/improvement needed**.

Overall, Idaho Power appears to be seeking out and leveraging learnings from industry and academic forums, and Idaho Power is pursuing pilot projects for multiple technologies that could be beneficial to its wildfire mitigation strategy. However, Idaho Power lists only minimal examples of learnings from its participation in international and national forums. The IE is also concerned that Idaho Power may not be adequately leveraging its participation in the IWRMC, especially given that many members of that consortium have maturing vegetation management programs. Idaho Power also does not identify a budget for pilots/emerging technologies, nor does it explain barriers or constraints to moving out of the pilot phase. For example, Idaho Power is piloting several technologies that have been successfully deployed by other utilities, such as wildfire detection cameras, EPS, and covered conductor. Given the risk on the system, and Idaho Power's substantial investment in vegetation management, bringing other technologies or operational practices to maturity could help reduce the overall cost of Idaho Power's Plan and/or increase its effectiveness. Finally, it is unclear, aside from wildfire cameras, how Idaho Power decided to pursue and/or pilot certain technologies.

3.9.3. Recommendations

In addition to cross-utility recommendations, the IE recommends the following:

IE_IP_32. Idaho Power should report its budget for emerging technologies/pilots and explain how it arrived at that budgeted sum and if that amount is sufficient to bring to maturity technologies that have been demonstrated as effective in other utility service territories.

IE_IP_33. Idaho Power should list all technologies/programs it considered piloting and explain why it selected those that are included in its WMP, detailing barriers to piloting certain technologies/programs that Idaho Power finds may be beneficial to its wildfire mitigation strategy, but for which Idaho Power has not pursued further action.

IE_IP_34. Idaho Power should list specific benchmarking it is conducting with utilities nationally and internationally. This information should be provided in tabular form, including the specific topic of benchmarking, or learning and resulting changes considered, as well as whether those changes were adopted, rejected, or deferred.

IE_IP_35. Idaho Power should explain the results of its EPS pilot and how, or if, it plans to deploy this methodology in the HFRZ. Results should include near misses, causes of outages on EPS lines, if known, and impacts on reliability.

3.10. OAR 860-300-0020(1)(k)

OAR 860-300-0020(1)(k) requires the utilities to describe its ignition inspection program, including how the utility will determine, and instruct its inspectors to determine, conditions that could pose an ignition risk on its own equipment or pole attachments. The IE interprets this section to target having a methodology for tracking and learning from ignitions as well as adhering to the Joint Use and other provisions of OAR 860-300-0018, many of which are considered in other portions of this evaluation.

3.10.1. Compliance with the OAR

The IE finds that Idaho Power has **partially met** the requirements of this section of the OAR.

Idaho Power demonstrates that it will implement the Joint Use provisions of OAR 860-024-018 if necessary, and that it has an ignition reporting program as well as an ignition and outages tracking database. Further, Idaho Power conducts root cause analyses for repetitive equipment or material failure, significant incidents, and near misses. However, Idaho Power provides virtually no detailed information on its outages,[8] root cause analyses (other than an example), and specific changes made to inspection standards because of ignition and outage tracking. Idaho Power states that in 2023 it benchmarked with several western utilities to learn about their ignition tracking methodologies, and in 2024 it will develop a roadmap to enhance its own ignition tracking process. Idaho Power further states that it considers the leading drivers of ignitions and lessons learned as part of its risk bowtie methodology but does not detail a list of leading ignition or outage drivers. Absent more data, the IE cannot determine if Idaho Power has fully met the requirements of this section of the OAR.

3.10.2. Efficiency

The IE finds that Idaho Power's response to this portion of the OAR is **potentially ineffective/improvement needed**.

The IE finds that, while Idaho Power does have an ignition and outage tracking program, the IE cannot independently make a finding of effectiveness. Idaho Power provides minimal detail related to information about the ignitions and outages tracked, including outages of unknown cause, and Idaho Power does not explain how outage information feeds into its inspection program. Further, although Idaho Power demonstrates that it has a root cause analysis program, Idaho Power does not describe how that program has led to changes in inspection procedures (or

[8] Idaho Power does provide outage metrics in Table 18; however, Idaho Power does not detail how outages inform its inspection and mitigation programs. Further, outage metrics lack an "unknown" category; therefore, the IE cannot ascertain how much risk may be on the system from unknown causes.

mitigation strategies). Not only is outage tracking a key leading indicator contributing to the development of a mitigation strategy, but also it can provide insights to avoid future ignitions. It is essential that the IE and OPUC have detailed insight into this data.

3.10.3. Recommendations

In addition to cross-utility recommendations, the IE recommends that:

IE_IP_36. Idaho Power should provide details of its ignition and outage database, including leading causes of outages and ignitions, number of unknown outages and ignitions of unknown cause, and historical outages and ignitions making up its baseline. Idaho Power should explain how it is reducing the number of outages/ignitions of unknown cause.

IE_IP_37. Idaho Power should detail all root cause analyses tracked since 2019 for which equipment failure could have resulted in an ignition (or a near miss), including equipment involved, findings, and how findings were integrated into the inspection and mitigation strategy.

IE_IP_38. In its 2024 WMP, Idaho Power should include its roadmap for its enhanced ignition tracking process based on its benchmarking with western utilities. This roadmap should include details of all changes Idaho Power intends to make, including anticipated benefits, and the timeline for implementing those changes.

4. CROSS-UTILITY RECOMMENDATIONS TO IMPROVE MATURITY

The IE has assessed that WMPs must be raised to a standard that the IE considers to be, in many cases, a minimum level of maturity to allow OPUC to independently determine that a utility acting under its WMP can reasonably be assumed to understand its risk and be sufficiently mitigating that risk at a reasonable cost. In addition, the IE finds many areas for continued maturity that are applicable to all utilities. The IE provides recommendations in the spirit of driving maturity such that utility ratepayers can be reasonably assured that their dollars are effectively reducing risk on the system, which at this point they cannot. Robust and accurate data is necessary to produce valid risk model outputs, which are used to inform appropriate mitigations. Further, utilities must be able to track and validate work with sufficient evidence to ensure that work was completed in a manner that results in the projected risk reductions.

Detailed cross-utility recommendations follow; a summary table containing recommendations and recommended timeframes for completion is set forth in Appendix C. The IE notes that for each recommendation, utilities currently demonstrate varying levels of maturity, including providing the recommended information. Inclusion of a recommendation does not necessarily mean that all three utilities failed to present the information; rather, the IE includes the cross-utility recommendations to raise plans to a level that should be expected given the number of years plans have been submitted in Oregon and based on experience elsewhere in the United States.

4.1. Standardized WMP Template

Each utility currently presents its WMP in a unique and non-standardized format. Unique presentations hinder the ability of the OPUC and the public to understand and compare/contrast information in each utility's WMP (and at times across Plan years). To increase public understanding and to facilitate evaluation of WMPs, the utilities should utilize a uniform, data driven WMP template that contains the same information in the same location in the WMP across all utilities. The public and any reader ought to be able to access any Oregon WMP and understand, for example, that "Section X" addresses mitigations and "Section Y" addresses PSPS preparation and communication. Further, uniformity of required information helps to make clear to the public and any reader areas where the utility excels versus areas where it may lack maturity. The IE recommends the following:

IE_ALL_01. Prior to submission of the next WMPs, the utilities should propose, and the OPUC approve, a WMP template containing standardized sections and subsections. The utilities can refer to California's 2023-2025 WMP Technical Guidelines (12/7/2022)[9] as a starting point for designing a standardized template, recognizing that there are differences between California and Oregon requirements. The proposed template should complement a set of standardized data reporting set forth in Recommendation IE_ALL_03.

WMP templates should include, at a minimum, the information contained in the following sections from the California 2023-2025 WMP Technical Guidelines, but the sections must be adapted to OAR 860-300-0020 requirements:

- Statutory Requirements Checklist - Section 3.
- Overview of WMP, including Sections 4.3 (Proposed Expenditures), 4.4 (Risk-Informed Framework).
- Overview of Service Territory, including Sections 5.1 (Service Territory), 5.2 (Electrical Infrastructure), 5.3 (Environmental Settings, including Fire Ecology (5.3.1), Catastrophic Wildfire History (5.3.2), High Fire Threat Districts (5.3.3), and (5.3.4)Climate Change).
- Community Values at Risk - Section 5.4, including 5.4.1 (Urban, Rural and Highly Rural Customers), 5.4.2 (Wildland-Urban Interfaces), and 5.4.3 (Communities at Risk from Wildfire). This information could be presented in a tabular rather than a narrative format.

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[9] See https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2023-wildfire-mitigation-plans/ accessed on April 8, 2024. The IE notes that California is reevaluating its technical guidelines in advance of the 2026-2028 base plan year filings.

- Risk Methodology and Assessment - Section 6, including all tables and schematics). The template should also include information contained in Appendix B to the level of granularity that the OPUC finds sufficient to support its evaluation.
- Wildfire Mitigation Strategy Development - Section 7, including all subsections modified to an appropriate time-fame (e.g. Table 7-3 could cover three years rather than 10 years).
- Wildfire Mitigations - Section 8. The IE emphasizes the importance of reporting on enterprise systems and data governance generally as well as workforce planning, open work orders, and quality assurance and quality control. (See, e.g. Section 8.1.5). In addition, the utility should be able to demonstrate the risk impact of proposed mitigations. The IE suggests that all subsections of Section 8 should be included; however, objectives may not be necessary.
- Section 9 - Public Safety Power Shutoff, including the information in subsections 9.1.1 (Key PSPS Statistics) and 9.1.2 (Identification of Frequently De-energized Circuits). Like Section 8, the IE recommends a focus on targets and performance metrics with the possible removal of objectives.
- Section 10 (Lessons Learned) combined with Section 11 (Corrective Actions). The IE recommends combining these two sections into one section.
- The IE does not recommend inclusion of Section 12 (Notices of Violation and Defect) unless the OPUC sees value in presenting this information in the WMP.

4.2. Standardized Terminology

The utilities present a variety of terms to represent the same or similar concepts. For example, each utility presents a different nomenclature to describe areas that are subject to heightened wildfire risk.[10] In addition, the utilities reference and use terms such as "ignition", "catastrophic wildfire", "outages", "grid settings", "sensitivity settings", "transmission lines", etc., in different ways such that the reader/evaluator cannot be certain that a term is being used uniformly across plans. Therefore, the IE recommends that:

IE_ALL_02. The utilities should develop a list of standardized terms and definitions and present that list to the OPUC for approval prior to submission of the next WMPs. The list of possible terms is extensive, and the IE will not attempt to capture them herein; however, the IE finds that the list must include a standardized term to describe areas at heightened risk of wildfire. The IE recommends the IOUs reference terms contained in Appendix A of the California 2023-2025 WMP Technical Guidelines as well as the definitions contained in each Oregon utility's WMP.

4.3. Standardized Data Reporting

The IE finds that the utilities present mostly narrative explanations to demonstrate fulfillment of the WMP requirements contained in OAR 860-300-0020 *et seq.*; however, the plans fail to present

[10] PGE denotes such areas as High Fire Risk Zones. Pacific Power uses the term Fire High Consequence Area (FHCA) used synonymously with their High Fire Risk Zones, and Idaho Power uses the term Wildfire Risk Zones and has two resulting tiers: Yellow Risk Zones (YRZs) also known as Tier 2 and Red Risk Zones (RRZ) also known as Tier 3).

sufficient data to enable the IE or OPUC to independently verify and evaluate the claims and decisions presented in the WMP. Further, the IE and OPUC cannot independently assess the quality of data nor whether the utility has appropriate data governance processes to ensure data integrity. Finally, data is presented at differing levels of granularity between plans and sometimes across plan years. Absent the ability to view and evaluate standardized data, it is not possible for the OPUC to determine that the utility is buying down an appropriate level of risk for the expenditures claimed in the WMP. At a minimum, the utilities should be able to report their assets, including tree attachments, risks on their system (including fall-in risk, outages, ignitions, etc.), resulting risk ranking at an appropriate level of granularity, mitigations, including risk buy-down, inspection results, PSPS events, spend, and performance metrics. Utilities should also list targets (goals) for each mitigation and performance against those targets.[11]

The IE recognizes that gathering and reporting data is an iterative process and that each utility may not be able to report all available data in the exact adopted template format before submission of WMPs in 2025. However, the need to develop capabilities in this area is not a reason to delay developing a standardized and data-driven reporting methodology. Indeed, setting the requirement now creates a clear roadmap towards data maturity.

Development of data reporting necessitates the development of a uniformly understood data schema. Further, the utility, as part of demonstrating data governance maturity, should be able to demonstrate linkages and uniformity of reporting across internal data sets. For example, a Circuit ID should be the same across all systems in the company, mitigations should be uniformly identified with a tracking ID, assets should be similarly tagged and noted (by latitude and longitude and with an appropriate ID) across systems, and vegetation should be uniquely identified and referenced to utility assets, etc.

Finally, data should be normalized where appropriate, and normalizing factors should be meaningful. This can be an iterative process that may develop and change over time. For example, normalizing data to Red Flag Warning Days may be appropriate for PSPS outages but may be less meaningful for ignitions. The utilities should propose normalizing factors in their data reporting template with the recognition that these may change over time as OPUC and the utilities mature in their development and evaluation of WMPs.

IE_ALL_03. Utilities should develop a standardized set of data, including schema, to be reported in an Excel and Geographic Information System format for submission on an annual basis concurrent with its WMP.[12] Utilities should submit the proposed data reporting framework to the OPUC for approval prior to submission of the next WMPs. Utilities could reference California's Quarterly Data Report (QDR) Utility Data Schema, QDR Wildfire Mitigation Data Tables 1-15, and

[11] Utilities should explain any significant deviations between targets and performance to those targets in their WMPs. What constitutes a significant deviation will need to be defined.
[12] The IE suggests that an annual reporting cadence may be sufficient as opposed to the quarterly reporting cadence currently in use in California but defers to the OPUC for the required cadence.

associated Data Guidelines[13] as a starting point for development of this Oregon WMP reporting requirement. The data framework should include the following information contained in the California QDR framework, modified to Oregon regulations and requirements:

Table 1 Mitigations (with removal of objectives)

Table 2 Performance Metrics

Table 4 Weather Patterns

Table 5 Risk Event Drivers (also known as near misses)

Table 6 Ignition Drivers

Table 7 State of Service Territory and Utility Equipment

Table 8 Location of Utility Equipment Additions or Removals

Table 9 Location of Utility Infrastructure Upgrades

Table 10 Recent Use of PSPS and other PSPS Metrics (recognizing that the term "fast-trip" may equate to enhanced sensitivity settings and should be uniformly applied)

Table 11 Mitigation Initiative Financials

Table 12 WMP midyear and End-of-Year Targets modified to annual targets or goals

Table 13 Open Work Orders/Notification (modify to Oregon regulations)

Table 14 HFTD Area Risk Summary

Table 15 Top Risk Circuit Scores

4.4. Multi-Year WMPs

Planning for and mitigation or wildfire risk is a multi-year, long-term process. A mature WMP planning process will find itself embedded into overall enterprise risk and climate adaptation/resilience plan with a clear understanding of grid-wide co-benefits; however, this represents the frontier of WMP risk planning. Given the long-term horizon for implementing mitigations, the IE recommends that all plans and targets therein cover multiple years. Further, as part of the natural maturing process that occurs in WMP planning, the IE recommends a base year/update year(s) approach to allow time for a utility to ascertain whether certain strategies are

[13] See https://energysafety.ca.gov/who-we-are/department-organization/data-analytics-division/ (accessed April 8, 2024).

working, while minimizing stranded costs associated with frequent changes in strategic direction. The IE recommends the following:

IE_ALL_04. Prior to submission of the next WMPs, utilities and OPUC should work together to set uniform years of coverage for each submitted WMP. Utilities and OPUC could also consider moving to a base-year and update year approach whereby large-scale changes in strategic direction are mostly limited to base years. The approach should designate a point in the utility planning/execution process at which work will continue even if a change in strategic direction deescalates the utility's understanding of the risk buy-down of a specific project.

4.5. Year-Ahead WMP Reporting

Currently, the Oregon utilities submit their WMPs inclusive of the WMP submission year. For example, utilities submitted WMPs that are the subject of this evaluation in late 2023, and evaluation is expected to be completed by mid-2024. This presents some regulatory risk for the utility because work is underway for which WMP approval has not been received.

IE_ALL_05. The utilities and OPUC should consider getting one year ahead in the planning process whereby each WMP being evaluated is for the work to be conducted in the coming year (e.g. plans submitted in December 2025 and evaluated in the first six months of 2026 would cover 2027 and beyond). If this recommendation were to be adopted, OPUC would need to develop a methodology for getting one year ahead and allowing for data true ups.

4.6. Standardization of Purpose and Use of Areas at Heightened Risk of Wildfire (HFRZs)

OAR 860-300-0020 (1)(a)(A)&(B) requires that each utility identify areas that are subject to a heightened risk of wildfire, including determinations for such inclusions, and are within the service territory of the utility and outside the service territory of the utility but within the utility's right-of-way for generation and transmission assets.[14]

The utilities have arrived at different understandings and determinations of "areas that are subject to a heightened risk of wildfire" such that comparison across utilities is difficult. Of greater concern is that absent a more standardized development of and understand of risk on the landscape, utilities could potentially use metrics that could overstate or understate risk resulting in over or underinvestment in mitigation measures. Finally, unique applications can result in potentially significant different understandings of risk at adjacent locations depending on which utility owns the assets.

There are multiple schools of thought on the development of underlying risk maps. Some methodologies attempt to capture and incorporate the value of assets at risk if a wildfire occurs (a

[14] Regulatory requirements are in summary and are not verbatim.

difficult and potentially contentious process), while others lean towards an understanding of fire behavior given the environmental conditions present on the landscape (fuels, fire behavior, historical wind patterns, etc.). Others use a blend of the two methodologies.

The IE recommends the State pursue a methodology that enables understanding of areas where fire may spread quickly or become widespread *regardless of ignition source*. Such areas, once determined, may be relatively static as compared to seasonal or day-to-day assessments of risk on the system. Indeed, given current climate trends, such areas could be expected to increase in size over time. Determining HFRZs can be viewed as a baseline measure of risk on which to consider the impact of utility risks and mitigations.

Importantly, determinations of areas of high risk should be independent or minimally dependent on the presence or absence of utility assets[15] or the actions a utility takes to mitigate the threat caused by a spark from its assets in an HFRZ. Undergrounding a line in a high-risk area does not mean that the area is no longer high risk if an ignition were to occur. Indeed, employing a methodology that removes designations of risk based on utility actions could result in unintended adverse outcomes; for example, utility personnel being cleared to operate equipment during high fire potential days that may cause sparks or arcs in an area where a line has been undergrounded.

IE_ALL_06. Ideally, the State of Oregon would develop a high fire risk map for use by all Oregon utilities whether community or investor-owned; however, absent this, the IE recommends that the utilities work together to develop significantly more standardized and uniformly applied maps identifying areas subject to heightened risk of wildfire based on fire behavior. IOUs should also coordinate with their cooperatively- or municipally-owned counterparts. Utilities should report on a timeframe and roadmap for standardization in their next WMP submissions.

4.7. Determining Wildfire Risk from Utility Assets

OAR 860-300-0020 (1)(b) requires that the WMP identify a means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk. The IE recognizes the Oregon IOUs for their continued maturation in understanding their wildfire risk, and the IE makes utility-specific recommendations elsewhere in this report. However, the IE presents several recommendations relating to risk modeling and mitigation selection applicable to all the utilities. (The IE addresses cost-benefit analysis in a separate section.)

4.7.1. Baseline Risk Determination & Performance Metrics

Key to understanding the efficacy of utility mitigations is the assessment of key performance metrics against a pre-determined baseline period. Some utilities do report historical metrics, such as ignitions, outages, etc.,(e.g. Idaho from 2019-2021) while others do not. The IE recognizes that

[15] Once high-fire risk areas have been determined, utility assets could be overlayed on the maps to refine borders to avoid incongruent results, for example a line passing in and out of a risk area because its direction does not comport with the map boundaries that was developed without this overlay.

not all utilities may have the necessary data to establish baseline historical risk performance metrics (such as ignitions and outages broken down by cause: vegetation contact, animal contact, equipment failure, etc., risk-events (also known as near-misses), etc.). Indeed, it is not clear that some utilities track performance metrics at all. However, absent establishment of a baseline and tracking of performance metrics, it is difficult to evaluate long-term risk reduction and mitigation efficacy. The IE recommends that:

IE_ALL_07. Utilities should establish a baseline period against which to measure wildfire mitigation performance. The baseline period need not be the same for all utilities but should be set to a timeframe before a utility deployed significant wildfire-specific mitigation measures. Utilities should propose the baseline period and rationale for that time period as the baseline in their next WMP submissions.

IE_ALL_08. Utilities should develop uniform performance metrics against which to evaluate future performance. Examples of possible performance metrics can be found in the data reporting templates currently in use in California (IE_ALL_03) and/or those used by Idaho Power. The utilities should present proposed performance metrics to OPUC prior to submission of the next WMPs and report out baseline performance metrics and year-over-year performance metrics since submission of their initial WMPs in their next WMP filing.[16]

4.7.2. Asset Registry

Utilities discuss an asset tracking system; however, it is unclear to the IE that each IOU can make an affirmative showing that it has a single-source-of-truth database that positively recognizes and locates all assets on the system at a granular (component) level. An asset registry should include all components designated by latitude/longitude and with a unique identifier consistently used across all systems in the company. Further, each piece of equipment should be logged and categorized, at a minimum, by age, manufacturer, installation date, and known defects/failures (and associated repairs).

IE_ALL_09. Each utility should demonstrate that is has a robust and granular asset registry system where assets are uniquely identified by a code consistently applied across all utility systems and where updates to asset information (health, age, installation date, manufacturer) flow from one single source and across all linked systems. Assets should be tracked by location (latitude/longitude, age, health, manufacturer, installation date, etc.). In addition, utilities should report elements of this data in aggregate and in a uniform fashion using the data tables set forth in previous recommendations.

[16] The IE recommends caution when evaluating future utility performance against baseline performance determinations. Performance in any given year can be affected by numerous elements outside the utilities' control (weather, insect infestations, moisture). Performance should be determined using outcomes over a period of time (several years at least) and normalized for fluctuating elements such as those mentioned above, among others.

4.7.3. Risk-Ranking of Circuits (or Segments/Spans/Zones)

All utilities present differing but maturing methodologies for calculating risk (likelihood multiplied by consequence) on their systems. The utilities state that the outcomes of risk models are used to select mitigations and prioritize work. However, absent presentation of risk outcome data, the evaluator lacks the ability to independently verify risk rankings and assess that mitigations are being implemented on high-risk circuits.

IE_ALL_10. The utilities should provide a risk-ranked listing of all circuits, circuit segments, spans (or some other appropriate level of granularity) in their next WMP submissions (and justify the granularity of the designation). This recommendation cross-references to Table 15 in IE_ALL_03. The utilities should explain how risk rankings change over time as mitigations are applied and demonstrate mitigations are incorporated into risk models.

4.8. Assessment of Risk Reduction vs. Costs

OAR 860-300-0020 (1)(b) and 1(i) pertain to the reporting of WMP costs balanced against mitigation benefits. The IE interprets these sections to pertain to both administrative costs associated with developing the WMP itself, but more importantly, the risk buy-down of various mitigations balanced against costs. In 2023, OPUC recommended that the utilities demonstrate progress towards developing a uniform risk-spend valuation methodology.

Given the magnitude of costs associated with the proposed mitigations in each utility's WMP and given that the WMP is the primary vehicle for demonstrating the reasonableness of mitigation measures, the IE finds that, while progress is being made, there is not sufficient data to fully evaluate the cost reasonableness of the Plans. The IE supports the need for a uniform methodology for calculating risk buy-down versus costs and recognizes that development of such a methodology takes time; however, in the interim, utilities should be able to demonstrate their independent assessments of costs versus risk reductions.

Further, it is unclear given current data whether the most effective mitigations are being deployed on the highest risk areas on the utility's system. It would be reasonable to expect that the vast majority (80 percent or more) of mitigations each year would be deployed on the highest risk areas (top 20 percent of risk), and recognizing that once applied, a mitigation can reduce risk on that circuit/segment/span, thus reorganizing the top-risk assets.

IE_ALL_11. Utilities should deploy a uniform framework for demonstrating cost/benefit (risk/spend) prior to submission of subsequent WMPs or provide a clear pathway to doing so. Utilities should leverage already existing frameworks in other states rather than developing a novel methodology from scratch, which is time consuming and costly. While differences are present across utilities and regulations, established frameworks exist and are publicly available for consideration. Utilities should also consider deploying a cost-benefit analysis given the reliance on more universally understood parameters (e.g. value of a statistical life) in the cost-benefit approach. If a cost-benefit analysis approach is not deployed, utilities should explain the rationale for using a risk-spend efficiency ratio approach. The adopted methodology should include both capital and O&M costs.

IE_ALL_12. Utilities should demonstrate their decision-making framework for selecting mitigations, including submitting the risk buy-down for each mitigation and a clear alternatives analysis, including methodology.

IE_ALL_13. Utilities should present mitigation costs broken down at a sufficient level of granularity to understand where dollars are flowing and associated risk buy-down. Utilities can leverage the data tables developed in IE_ALL-03. OPUC may wish to consider requiring additional filings in this year's docket to demonstrate risk buy-down and associated cost effectiveness, which are not demonstrated by the current plans, as a condition of approval.

4.9. PSPS as a Risk

All utilities present and describe wildfire risk on their system (caused by utility equipment and present on utility equipment from externally ignited wildfires); however, it is unclear to the IE whether any utility captures risk to customers resulting from the deployment of PSPS as a mitigation measure. Deployment of PSPS may reduce the risk of wildfire caused by utility equipment to near zero; however, it results in other risks to customers reliant on electric service, especially those customers designated as Access and Functional Needs (e.g. customers dependent on durable medical equipment, medications that must be kept at certain temperatures, etc.). Therefore, PSPS should be viewed as a mitigation of last resort that should be deployed as surgically as possible to mitigate reliability consequence.

IE_ALL_14. Utilities should be able to demonstrate that PSPS risk is calculated and weighted in its risk model and show how PSPS risk is considered when selecting PSPS as a mitigation measure.

4.10. Mitigating PSPS Risk Through Identification of Frequently De-Energized Circuits and Associated Customer Mitigations

Recognizing that PSPS provides both wildfire mitigation benefits and creates reliability risk, utilities should be tracking the frequency of deployment of PSPS across the system as well as offering methods for mitigating the adverse impacts of PSPS, especially on vulnerable customers. The IE recognizes that some utilities are already proactively piloting or deploying back-up generation, such as portable batteries, as well as proactively identifying vulnerable populations. As such, the IE offers the following recommendations:

IE_ALL_15. Utilities should report out the number of de-energization events (including events for which notice was given but power remained on) across its service territory at the most granular level possible[17] and, for those circuits that are frequently de-energized (as that term is ultimately

[17] See Table 10 in IE_ALL_03 and Section 9.1.2 in IE_ALL_01 for examples of how the utility could report this information.

defined), the utility should report how it will reduce de-energization frequency on the circuit (or segment/span) and over what time horizon. If the utility has not or has minimally deployed PSPS, the utility should conduct analyses on previous weather events for which a PSPS would have been deployed had the tool been available to develop insights into potentially frequently de-energized circuits.

IE_ALL_16. Utilities should report on programs and pilots meant to reduce PSPS risk on vulnerable populations, as that term is defined, including potential deployment of back-up generation, such as portable batteries. Utilities should detail how customers were identified and selected for PSPS mitigations and the percentage of vulnerable customers offered mitigations as compared to the identified total eligible population.

IE_ALL_17. Utilities should provide greater insight into the methodology for citing customer resource centers (CRCs). Utilities should be able to demonstrate that selected locations and numbers of CRCs are tied to an understanding of the number of vulnerable customers potentially impacted and that the location and number of CRCs has been vetted by local public safety partners and community-based organizations. To meet this recommendation, the utilities would need to demonstrate how vulnerable (AFN) customers are identified and tracked and explain why the number and location of CRCs is appropriate given the number of vulnerable (AFN) customers.

4.11. Changes to PSPS Thresholds

There are many elements that factor into a determination to deploy a PSPS. However, as hardening measures and other mitigations are deployed, it is reasonable to assume that the criteria to deploy PSPS should change. For example, replacing wood poles with steel poles could increase the wind threshold under which the utility would consider deploying PSPS in a particular location. The IE recommends that:

IE_ALL_18. Utilities should report out at the circuit or circuit segment/span or other appropriate level of granularity how they expect implementation of mitigation measures to impact thresholds for deploying PSPS over the Plan period as well as how PSPS risk itself is reduced through deployment of mitigation measures.

4.12. Impact of Operational Mitigations on Reliability

Several utilities report reliability metrics related to operational mitigations (e.g. reclosers); however, metrics are not universally reported. In addition, it appears that there is limited deployment across the utilities of increased sensitivity settings whereby a line trips at a lower threshold than during normal operations.

IE_ALL_19. Utilities should develop a uniform set of reporting metrics to measure the impacts of operational mitigations on reliability (in addition to reporting on these mitigations' wildfire risk impact discussed elsewhere). Operational mitigation reliability reporting should be broken out by mitigation (e.g. increased/enhanced sensitivity settings, changes in recloser settings, etc.).

4.13. Asset Inspection Find/Repair Rates and Trends

Each utility presents methodologies for asset inspection cadence, designations of severity and resulting repair timeframes; however, not all utilities report their performance against these methodologies, including trends.

IE_ALL_20. Utilities should report their performance against their asset inspection standards, including find rates for each level of severity both in and outside of high risk areas, on-time close rate, any backlog, plan to reduce backlog (including whether location based, risk-based or time-based), find trends and, if find trends exist, how those trends are incorporated into risk models and resulting changes on the system, and time lag between field work and entry into the system of record.

4.14. Asset Inspection Quality Assurance/Control

Utilities present varying asset inspection and quality control measures; however, it is difficult to glean how assets are selected for quality control (when less than 100 percent are evaluated), quality control passage rates, and any measured difference between in-house versus contracted inspectors (if contracted inspectors are used).

IE_ALL_21. Utilities should present their quality control performance and target quality rates for the duration of the Plan. Utilities should justify asset inspection selection processes for inspections of less than 100 percent of assets (and for 100 percent, why that number is appropriate). In addition, utilities should explain any pervasive findings and resulting changes. Finally, utilities should report on any differences in quality control passage rates between in-house and contracted inspectors and associated remedies.

4.15. Maturing Vegetation Management

Proposed vegetation management expenditures are significant. Both Idaho Power and PGE apportion the bulk of their O&M expenses towards vegetation management, and O&M expenditures are sizable compared to capital expenditures. Therefore, it is vital that utilities rapidly mature their vegetation management capabilities to maximize risk reduction while reducing environmental impact and costs to ratepayers. An indicator of a maturing vegetation management program is often a targeted program based on an understanding of risk combined with system hardening/operations such that the system is better able to withstand or respond to vegetation contact. In many cases, vegetation management scope and expenditures should decrease over time as operational or hardening measures are deployed. The IE makes the following recommendations related to overall vegetation management programs. Vegetation inspections are addressed in the subsequent section.

IE_ALL_22. Utilities should report on whether they have a comprehensive tree inventory, including species, health, age, height, estimated mature height (if young), etc. Utilities should report on how individual trees are identified (including removals and additions), how trees are tied to nearby utility assets (including whether the vegetation inventory relies upon a single-source-of-truth asset registry), the lag time between findings in the field and entry into the system, and whether there is a single underlying data source identifying trees/vegetation that is used across all relevant software platforms in the company and whether changes in the single data source system flow to other platforms.

IE_ALL_23. Utilities should demonstrate that they are tracking vegetation related outages and ignitions to understand the characteristics of trees/vegetation involved and creating a feedback loop to inform vegetation management practices. Utilities should report the types of vegetation most frequently involved in contacts. If utilities are already tracking this information, they should demonstrate how this nuanced understanding of vegetation is being accounted for in risk modeling and resulting vegetation management mitigations, including frequency and extensiveness of vegetation management for different tree species and landscape management (e.g. working with partners to replace high blow-in risk trees with lower blow-in risk vegetation or fuel load management projects where appropriate).

IE_ALL_24. Utilities should demonstrate that trees identified for remediation are worked in a risk-based manner with highest risk areas and highest-risk tree species being worked earlier in the year. Some utilities do provide vegetation management plans where vegetation in higher risk areas (for example a Tier 3 area in Idaho Power's service territory) are prioritized for work. However, it is unclear that work is prioritized based on an understanding of risk at a more granular level, such as a circuit or circuit segment level.

IE_ALL_25. Utilities should clearly identify all vegetation management programs and show that programs are not duplicative. Further, utilities should detail the computer systems/programs used to track vegetation management programs including whether vegetation is identified with a unique identifier that flows across all systems/programs. Utilities should detail how information flows across all programs (if there are multiple programs) to ensure accuracy of information, and utilities should describe steps being taken to ensure quality and accuracy of data collected across systems, including any efforts to merge systems.

IE_ALL_26. Utilities should report on the customer refusal rate for all trees designated to be worked or removed in the previous year. Utilities should detail their process for addressing customer concerns, and, if access is not granted, how risk is otherwise remediated (including hardening or operational measures) and how that ongoing risk is accounted for in utility risk models and resulting mitigation decisions.

IE_ALL_27. Utilities should report how slash is addressed. Utilities should include information on whether slash is chipped, removed, or left unaltered and, for chipping and slash left behind, the condition and location of the debris. Finally, utilities should demonstrate that they have procedures in place (and that those procedures are followed) to ensure slash is not blocking waterways, impacting ingress/egress, or otherwise causing damage to the ecosystem.

IE_ALL_28. Utilities should demonstrate that contractors used for vegetation management have the appropriate training and certifications to ensure trees are properly worked. For example, on a vegetation management crew, it is generally recommended that the crew foreperson would possess appropriate International Society of Arboriculture certifications and any other utility-required certifications. In addition, utilities should demonstrate that their Requests for Proposals and resulting contracts clearly detail requirements to ensure that vegetation is worked consistently whether work is conducted by a utility employee or contractor. Utilities should report on the percentage of vegetation management work, if any, performed by in-house crews versus contracted crews and whether quality control is conducted by in-house or contracted employees.

IE_ALL_29. Utilities should demonstrate that they have the appropriately sized workforce, including contractors, to deliver on their vegetation management programs over the duration of the Plan, and if not, how they intend to bolster the workforce to ensure that programmatic goals are achieved.

4.16. Vegetation Hazard Identification Program, Quality Assurance/Quality Control

Utilities discuss their varying vegetation management inspection programs; however, given that utilities rely heavily on vegetation management as a mitigation measure, and at significant cost, more information is needed to determine the effectiveness of remediation programs. For example, some utilities discuss the use of patrol inspections in high-risk areas, but it is unclear how patrols are conducted. Additionally, patrols can occur on foot or by vehicle, and patrols can involve inspection of only one portion of the tree (for example, facing the road on a drive-by inspection) or can be 360-degree inspections. At times, inspections can also deploy intrusive methods or rely solely on upon external/visual inspections. In addition, the timing of pre- and post-work inspections is critical to measuring the quality of work undertaken. Finally, vegetation management programmatic performance is critical; therefore, reporting on vegetation related outages and ignitions is essential. The IE recommends the following:

IE_ALL_30. Utilities should detail the types and frequency of different patrol/hazard tree identification methodologies employed and the criteria for determining the type of inspection undertaken, including vehicle, on-foot, and 360-degree patrols.

IE_ALL_31. Utilities should detail the timing of pre- and post-work quality control inspections, including how quickly after vegetation is identified for work and how quickly after vegetation is remediated quality control is conducted. The utility should also report the rate at which hazard vegetation identified for pre-work quality control is already remediated prior to quality control being conducted (if at all).

IE_ALL_32. Utilities should report their performance against their vegetation inspection remediation standards, including find rates for each level of severity both in and outside of high risk areas, on-time close rate, any backlog, plan to reduce backlog (including whether location based, risk-based or time-based), find trends; and if find trends exist, how those trends are incorporated into risk models and resulting changes on the system, and time lag between field work and entry into vegetation management systems and risk models.

IE_ALL_33. Utilities should report their quality control internal passage rate target and report on progress against that target for each element of their vegetation management quality control. For example, an internal target might be a 95 percent passage rate, while actual might be 94.5 percent.

4.17. Criteria for Assessing Co-Benefits

OAR 860-300-020(1)(i) requires utilities to consider technologies that offer co-benefits to the utility's system. Utilities take different approaches to reporting on co-benefits, all of which could benefit from increased rigor. The IE recommends:

IE_ALL_34. Utilities should develop standardized criteria for assessing co-benefits, including definitions. The IE recommends the definitions and criteria contained in Idaho Power's WMP as a starting point.

IE_ALL_35. Utilities should begin to develop a methodology for quantitatively calculating and reporting on co-benefits associated with various mitigations. Utilities should report on progress and methodology in their subsequent WMPs.

4.18. Identifying Lessons Learned & Technology Pilots

OAR 860-300-020(1)(j) requires the utilities to describe their participation in national and international forums and describe research conducted to maintain expertise in leading-edge technologies and operational practices. While all utilities report on their participation in a wide variety of forums, there are significant differences in reporting on changes/updates to WMPs as a result. The IE recommends the following:

IE_ALL_36. As part of the WMP template, utilities should develop a standardized way of reporting participation in various forums and research, and specific changes slated to be made or being considered based on knowledge/experience gained. Information should be presented in a tabular format and include the major areas of a WMP strategy, including risk, situational awareness, grid hardening, grid operations, vegetation management, etc. and resulting changes/pilots/research the utility is deploying.

4.19. Implementing a Maturity Model

In the opinions adopting the utilities' 2023 WMPs, OPUC requested that the utilities evaluate the Office of Energy Infrastructure Safety's maturity model[18] and report on feasibility of implementing that model in Oregon. Utilities reported back on both that model as well as a model developed by the International Wildfire Risk Mitigation Consortium (IWRMC) and offered varying opinions on the value and feasibility of implementing a model.

The purpose of a maturity model framework is for utilities to clearly identify current and future maturity over the life of the WMP according to a standardized framework. A best practice in developing a maturity model is to calibrate the model over certain time periods to ensure that current best practices are incorporated into the model, which can result in utility scores changing against best practices between iterations. Application of a maturity model in the wildfire space is still in its early phases; however, deployment of a model, even if it is less than perfect, provides valuable insight to utilities, regulators, and the public. The IE recommends the utilities start with the IRWMC model

IE_ALL_37. In their 2025 WMPs, utilities should explain how they will deploy the IRWMC maturity model and, if already deployed, the utilities should report on maturity across the Plan years for each capability. Utilities should explain the rubric for calculating each element of maturity.

[18] The OPUC decisions refer to the California Public Utilities Commission's Wildfire Safety Division maturity model. In July of 2021, the Wildfire Safety Division became an independent office of the California Natural Resources Agency (the Office of Energy Infrastructure Safety (OEIS)). In 2022, OEIS released an updated version of its maturity model for use in its 2023-2025 WMP evaluations.

APPENDIX A: COMPLIANCE WITH OAR 860-300-0020 ET SEQ. & EVALUATION OF PLAN EFFECTIVENESS

Table 2. *IE Assessment of Idaho Power's WMP*

Code	Requirement	Assessment of Compliance (Met/Partially Met/Did Not Meet)	Assessment of Plan Effectiveness (Sufficiently Effective or Potentially Ineffective/Improvement Needed)
OAR 860-300-0020 (1)(a)(A)+(B)	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	Met	Likely Effective
OAR 860-300-0020 (1)(b)	Identified means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk	Partially Met	Potentially Ineffective/Improvement Needed
OAR 860-300-0020 (1)(c)	Identified preventative actions and programs that the utility will carry out to minimize the risk of the utility's facilities causing wildfire	Met	Potentially Ineffective/Improvement Needed
OAR 860-300-0020 (1)(d)	Discussion of the outreach efforts to regional, state, and local entities, including municipalities, regarding a protocol for the de-	Met	Potentially Ineffective/Improvement Needed

	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		
OAR 860-300-0020 (1)(e)	Identified protocol for the de-energization of power lines and adjusting of power system operation 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 860-300-040 through 860-300-050	Met	Potentially Ineffective/Improvement Needed
OAR 860-300-0020 (1)(f)	Identification of the community outreach and public awareness efforts that the utility will use before, during, and after a wildfire season, consistent with OAR 860-300-040 through 860-300-050	Met	Potentially Ineffective/Improvement Needed
OAR 860-300-0020 (1)(g)	Description of the procedures, standards, and timeframes that utilities will use to inspect utility infrastructure in areas it has identified as heightened risk of wildfire, consistent with OAR 860-024-0018	Met	Potentially Ineffective/Improvement Needed
OAR 860-300-0020 (1)(h)	Description of the procedures, standards, and timeframes that the utility will use to carryout vegetation management in areas it has identified as heightened risk of wildfire, consistent with OAR 860-024-018	Met	Potentially Ineffective/Improvement Needed

OAR 860-300-0020 (1)(i)	Identification of the development, implementation, and administrative costs for the Plan, which includes discussion of risk-based cost and benefit analysis, and considerations of technologies that offer co-benefits to the utility's system	Partially Met	Potentially Ineffective/Improvement Needed
OAR 860-300-0020 (1)(j)	Description of participation in national and international forums, including workshops identified in section 2, chapter 592, Oregon Law 2021, as well as research and analysis the utility has undertaken to maintain expertise in leading-edge technologies and operational practices, and how such technologies and operational practices have been used to develop and implement cost effective wildfire mitigation solutions	Partially Met	Potentially Ineffective/Improvement Needed
OAR 860-300-0020 (1)(k)	Description of ignition inspection programs, as described in Division 24 of these rules, including how the utility will determine and instruct its inspectors to determine conditions that could pose an ignition risk on its own equipment and pole attachments	Partially Met	Potentially Ineffective/Improvement Needed

APPENDIX B: UTILITY-SPECIFIC RECOMMENDATIONS

Table 3. *Summary of Utility-Specific Recommendations: Idaho Power*[19]

IE ID Number	Description	Recommended Completion Date
IE_IP_01	Explain 240-meter limit for HFRZ and explain how risks to assets from outside sources is modeled	With 2025 WMP Submissions
IE_IP_02	Report breaks used to differentiate between YRZs and RRZs	With 2025 WMP Submissions
IE_IP_03	Explain incorporation of vegetation grow-back in burn scars	With 2025 WMP Submissions
IE_IP_04	Clarify inclusion (or not) of undergrounded resources in HFRZ determinations	With 2025 WMP Submissions
IE_IP_05	Provide schematic of all models used to determine risk and how models work together	With 2025 WMP Submissions
IE_IP_06	Provide table with key risk drivers, including weighting of those drivers in risk models, detail methodology for determining risk drivers, explain incorporation of less frequent and extreme events into risk modeling	With 2025 WMP Submissions
IE_IP_07	Provide timeframe for outage and ignition data used in risk model and explain how each is considered in risk methodology	With 2025 WMP Submissions
IE_IP_08	Demonstrate cost-benefit methodology for planned expenditures, including risk buy-down	Before 2025 WMP Submissions
IE_IP_09	Justify mitigation focus on transmission	With 2025 WMP Submissions
IE_IP_10	Report results of covered conductor study, including barriers to implementation. Provide covered conductor commitments	With 2025 WMP Submissions
IE_IP_11	Provide alternative/co-mitigation analysis for vegetation management on riskiest circuits	With 2025 WMP Submissions

[19] Detailed recommendations are contained in the body of this report.

IE_IP_12	Explain if tabletop exercises held for wildfire preparation (not just PSPS preparation)	With 2025 WMP Submissions
IE_IP_13	Report on whether track primary and secondary 24-hour contacts for PSPs and process for ensuring up to date	With 2025 WMP Submissions
IE_IP_14	Explain what forums, from whom, and how PSP feedback solicited and describe how feedback from 2023 and 2024 implemented	With 2025 WMP Submissions
IE_IP_15	Explain operation within ICS framework, including training	With 2025 WMP Submissions
IE_IP_16	Demonstrate how non-English speakers can access PSPS information. Explain prevalence of languages spoken within service territory	With 2025 WMP Submissions
IE_IP_17	Demonstrate availability of real-time PSPS information from homepage	With 2025 WMP Submissions
IE_IP_18	Demonstrate benchmarking to other utilities who have called PSPS events	With 2025 WMP Submissions
IE_IP_19	Explain identification process for AFN customers and if a positive contact protocol is in place	With 2025 WMP Submissions
IE_IP_20	Explain how CBOs are proactively identified	With 2025 WMP Submissions
IE_IP_21	Justify cadence of tabletop exercises and describe feedback received and changes made as a result	With 2025 WMP Submissions
IE_IP_22	Demonstrate that wildfire preparedness information is available to non-English speakers. Demonstrate partnership with CBOs to expand reach for wildfire preparedness	With 2025 WMP Submissions
IE_IP_23	Explain assessment of customer awareness and understanding of PSPS and wildfire preparedness outreach	With 2025 WMP Submissions
IE_IP_24	Explain any further prioritization of defects beyond Priority repair timelines	With 2025 WMP Submissions
IE_IP_25	Explain rationale for increased cadence of inspections in RRZ but not YRZ	With 2025 WMP Submissions

IE_IP_26	Explain analysis of inspection find trends and resulting inspection procedure updates	With 2025 WMP Submissions
IE_IP_27	Explain rationale for increased patrols/pruning in RRZ but not YRZ	With 2025 WMP Submissions
IE_IP_28	Explain if vegetation management work further prioritized based no risk rankings	With 2025 WMP Submissions
IE_IP_29	Explain if areas requiring heavy vegetation management are evaluated for alternative mitigations, including thresholds	With 2025 WMP Submissions
IE_IP_30	Explain how vegetation management findings are evaluated and integrated into future inspection protocols. Report quality control find rates and differences between in-house vs. contracted inspections	With 2025 WMP Submissions
IE_IP_31	Explain rationale for distribution pole clearing and changes to equipment reduces need for pole clearing	With 2025 WMP Submissions
IE_IP_32	Report budget for emerging technologies/pilots, including sufficiency of amount allocated	With 2025 WMP Submissions
IE_IP_33	List all pilots considered and explain rationale for those selected, including barriers	With 2025 WMP Submissions
IE_IP_34	Detail specific utility benchmarking, including whether learnings were adopted, rejected, or deferred	With 2025 WMP Submissions
IE_IP_35	Report results of EPS pilot including deployment plans	With 2025 WMP Submissions
IE_IP_36	Provide details of ignition tracking database including elements tracked, leading causes of outages and ignitions, unknown outages/ignitions factoring into baseline. Explain if reducing number of ignitions/outages of unknown cause	With 2025 WMP Submissions
IE_IP_37	Detail root cause analyses tracked since 2019 for equipment failures and explain how findings integrated into inspection and mitigation strategy	With 2025 WMP Submissions
IE_IP_38	Provide roadmap for enhanced ignition tracking process	With 2025 WMP Submissions

APPENDIX C: CROSS-UTILITY RECOMMENDATIONS

Table 4. *Summary of Cross-Utility Recommendations*[20]

IE ID Number	Description	Recommended Completion Date
IE_ALL_01	Create standardized WMP template	Prior to 2025 WMP Submissions
IE_ALL_02	Create standardized terms and definitions	Prior to 2025 WMP Submissions
IE_ALL_03	Create standard annual data submissions, including schema; submit data with next WMP	Prior to 2025 WMP Submissions
IE_ALL_04	Set uniform years of coverage across WMPs	Prior to 2025 WMP Submissions
IE_ALL_05	Consider year ahead WMP submissions	Prior to 2026 WMP submissions
IE_ALL_06	Create consistent HFRZ methodology across utilities	With 2025 WMP submissions
IE_ALL_07	Establish and report on baseline performance metrics	With 2025 WMP submissions
IE_ALL_08	Develop standardized performance metrics and report performance	With 2025 submissions (Related to IE_ALL_03)
IE_ALL_09	Demonstrate asset registry and consistent use of asset IDs across systems and programs	With 2025 WMP submissions
IE_ALL_10	Provide risk-ranking of all circuits (or other level of granularity)	With 2025 WMP submissions
IE_ALL_11	a. Deploy uniform framework for assessing cost/benefit; b. consider implementing a cost-benefit analysis or justify use of RSE	a. With 2026 WMP submissions b. With 2025 WMP submissions
IE_ALL_12	Present mitigation decision-making framework and alternatives analysis	With 2025 WMP submissions
IE_ALL_13	Present mitigation costs broken down by mitigation and associated risk buy-down	Prior to 2025 WMP submissions (supplemental filing)

[20] Detailed recommendations are contained in the body of the report.

IE_ALL_14	Demonstrate that PSPS is included as a risk in risk-modeling frameworks	With 2025 WMP submissions
IE_ALL_15	Report PSPS events and identify frequently (or potentially frequently) de-energized circuits Describe approach to reduce PSPS events on those circuits	With 2025 WMP submissions
IE_ALL_16	Report on programs/pilots to reduce impact of PSPS on vulnerable customers. Explain how customers are identified and selected for pilots/programs	With 2025 WMP submissions
IE_ALL_17	Explain rationale for CRC locations	With 2025 WMP submissions
IE_ALL_18	Explain how mitigations will change PSPS thresholds	With 2025 WMP submissions
IE_ALL_19	Develop uniform reliability reporting and provide results	With 2025 WMP submissions
IE_ALL_20	Report performance to asset inspection standards, including find rate, backlog, on-time close rate, etc.	With 2025 WMP submissions
IE_ALL_21	Report QC performance and target QC metrics, report on trends, explain asset selection process	With 2025 WMP submissions
IE_ALL_22	Describe tree inventory, how trees are identified, how data moves across the system, lag time between find and entry to system	With 2025 WMP submissions
IE_ALL_23	Describe vegetation related outages at the species level and feedback loop for the vegetation management program	With 2025 WMP submissions
IE_ALL_24	Describe how identified vegetation is prioritized for remediation in a risk-based manner	With 2025 WMP submissions
IE_ALL_25	Identify all vegetation management programs and demonstrate that they are not duplicative; explain vegetation management data governance	With 2025 WMP submissions
IE_ALL_26	Report on customer refusal rate for vegetation management and how risk model/mitigations are adjusted	With 2025 WMP submissions
IE_ALL_27	Describe how slash is addressed	With 2025 WMP submissions
IE_ALL_28	Describe contractor training program and percentage of vegetation management work performed by in-house versus contracted employees	With 2025 WMP submissions

IE_ALL_29	Demonstrate workforce capacity to address vegetation management programs	With 2025 WMP submissions
IE_ALL_30	Detail types and frequency of different patrol/hazard tree identification and criteria for determining inspection type	With 2025 WMP submissions
IE_ALL_31	Detail timing of pre- and post-work QC	With 2025 WMP submissions
IE_ALL_32	Report performance against vegetation management standards, including find rate, backlog, etc.	With 2025 WMP submissions
IE_ALL_33	Report QC passage rate and target	With 2025 WMP submissions
IE_ALL_34	Develop standardized criteria for assessing co-benefits	With 2025 WMP submissions
IE_ALL_35	Develop methodology for quantifying co-benefits	With 2026 WMP submissions
IE_ALL_36	Develop standardized forum/research participation template including changes/pilots across mitigations	With 2025 WMP submissions
IE_ALL_37	Explain how will deploy IRWMC maturity model and, if already deployed, report results	With 2025 WMP submissions