Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

February 1, 2022

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: UE 394 – Portland General Electric Company's Request for a General Rate Revision
PGE Surrebuttal Testimony

Dear Filing Center:

Included for filing in the above referenced docket is Portland General Electric Company's Surrebuttal Testimony containing:

- PGE 2400 / Level III Outage
- PGE 2500 – 2508 / Fee Free Bank Card
- PGE 2600 / Faraday Repowering
- PGE 2700 – 2704 / Trojan NDT
- PGE 2800 – 2810 / Wildfire & Vegetation Management
- PGE 2900 / Deferrals
- PGE 3000 – 3004 / Pricing

Confidential material in support of this filing has been provided to parties under the General Protective Order No. 21-206 issued June 24, 2021 and Modified Protective Order 21-237 issued July 27, 2021. Parties have agreed to use Huddle to distribute confidential and highly confidential exhibits.

Work papers will be emailed to puc.workpapers@puc.oregon.gov, and posted to Huddle.

Additionally PGE requests that all data requests in this docket be submitted via Huddle and addressed to:

Jaki Ferchland
Portland General Electric Company
Manager, Revenue Requirement
121 SW Salmon Street
Portland, OR 97204

Please direct all formal correspondence, questions, and requests related to this filing to pge.opuc.filings@pgn.com

Sincerely,

/s/ Jay Tinker

Jay Tinker
Director, Rates & Regulatory Affairs

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Level III Outage Mechanism

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Larry Bekkedahl
Alex Tooman, Ph.D.

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Larry Bekkedahl. I am the Senior Vice President of Advanced Energy Delivery. My qualifications were previously provided in PGE Exhibit 500.

My name is Alex Tooman. I am a Senior Regulatory Consultant for PGE. My qualifications were previously provided in PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony provided by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Oregon Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to PGE's proposal to revise the Level III outage mechanism (Mechanism).

Q. Please summarize your proposal to revise the Mechanism.

A. PGE proposes to modify the current asymmetric mechanism into one that allows negative balances, but would be limited by maximum balances, and would entail PGE sharing costs with customers (for specific details see Section IV, below). This proposal responds to the Commission's direction that PGE return in this rate case with a proposal supported by additional justification and a chain of causation. PGE's proposed changes to the Mechanism will help ensure that PGE can continue to prioritize safety, reliability, and the prompt restoration of service following outage events.

Q. Do Parties agree with PGE's proposal?

A. No. While Staff and CUB agree that revisions to the Mechanism are appropriate, Staff proposes only an annual update to the accrual, and CUB continues to agree that a negative balance is reasonable but with lower caps and no sharing. AWEC believes that no change to PGE's mechanism is warranted.

Q. What specific issues do you address in your testimony and how is it organized?

A. We address the following issues:

- Section II – Establish the facts regarding PGE's Level III events;
- Section III – Respond to Parties' concerns regarding risks and incentives; and
- Section IV – Summary and Conclusions

II. PGE's Level III Events

Q. Why do you need to establish the facts regarding PGE's Level III events (Events)?

A. Parties make a number of representations in testimony regarding PGE's historical Events and how they justify each party's view of the Mechanism. We will use this section to clarify and correct the record on the history of PGE's Events.

Q. What clarifications and corrections do you need to make?

A. AWEC and Staff have provided certain data and analyses that are incomplete or erroneous and need to be updated for all available information. We address this in Section A, below. CUB has argued that wildfire-related costs are inappropriate to include in the recognized Events or Mechanism. We address this in Section B, below.

A. Analysis of PGE's Events

Q. What information from AWEC and Staff do you need to clarify or correct?

A. AWEC updates PGE's historical Event data to include $10.0 million from 1995 and Staff presents two graphs, both of which lead to erroneous conclusions regarding the need for revising the Mechanism. We respond to these arguments and provide a complete set of information to more fully address the issue of PGE's Events, their possible relation to climate change, and how they justify revising the Mechanism.

Q. What, specifically, does AWEC claim with regard to the 1995 event?

A. AWEC asserts that "PGE starts its analysis in 1996 and ignores $10,000,000 in costs that PGE had attributed to 1995 in connection with these events."[1] Based on this additional data point, AWEC concludes that: "PGE's analysis demonstrates that the distribution of Level III storm

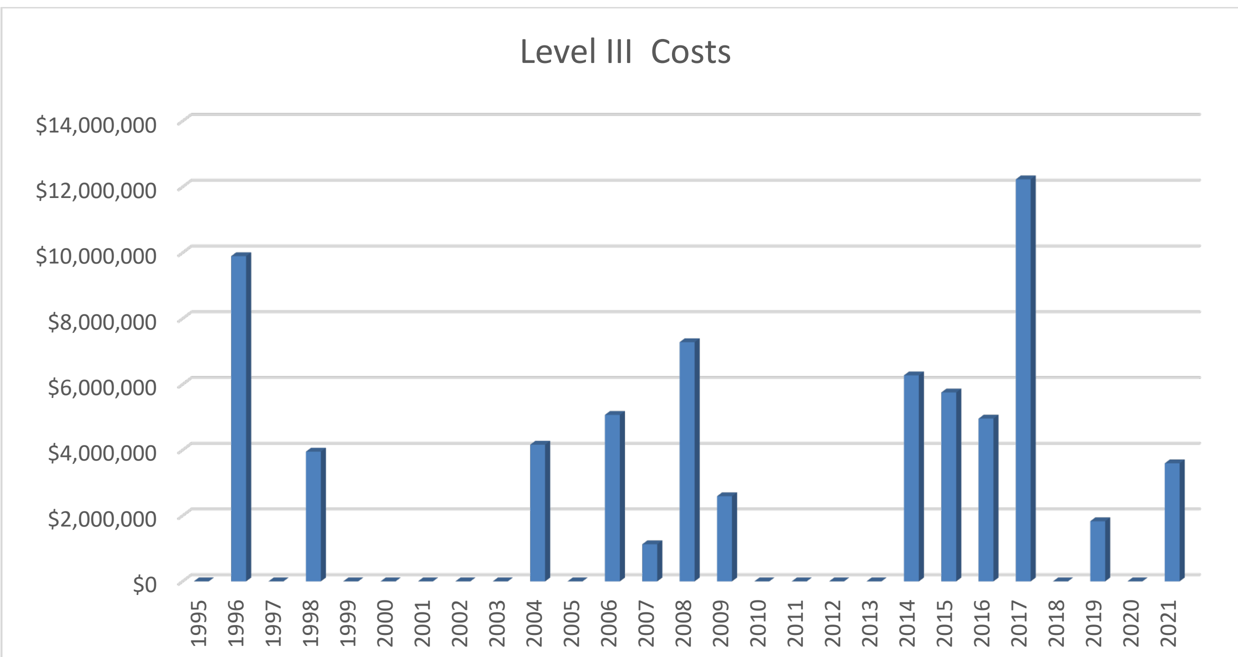
[1] AWEC/300, Mullins/21.

costs has been relatively uniform over time" and "Level III storm costs actually declined over the 27-year period."[2]

Q. How do you respond to AWEC's assertions?

A. First, PGE observes that the December 12, 1995 event that led to the $10.0 million costs referenced by AWEC was declared an emergency by then Governor Kitzhaber. We had specifically excluded declared emergencies from PGE Exhibit 1405 to address events relating solely to the Mechanism. If all declared emergencies are *excluded* from the analysis, PGE's Events can be graphically depicted as follows:

Figure 1
Summary of Costs Attributable to Level III Events Excluding Declared Emergencies
1995-2021 ($2021)

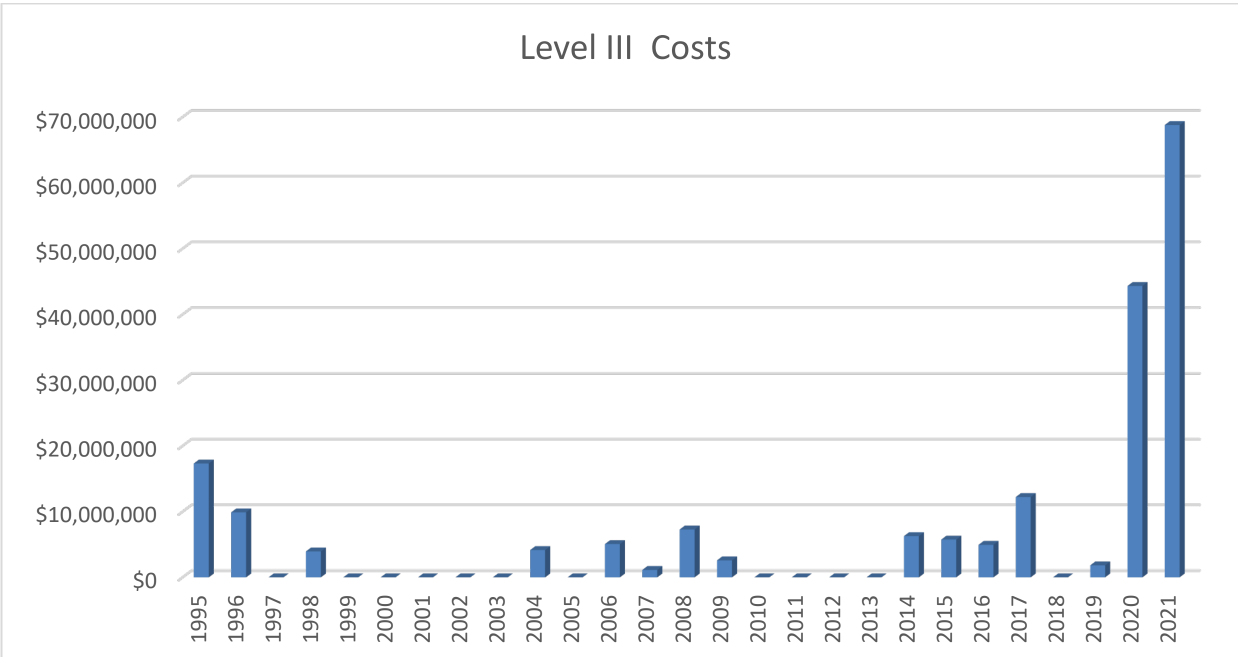


Q. How does the above graph change if you include declared emergencies?

[2] AWEC/300, Mullins/21.

A. If AWEC is correct that we should add the 1995 declared emergency, then we should also add the 2020 and 2021 declared emergencies for consistency and a more complete depiction of Event costs and the impacts of climate change.[3]

Figure 2
Summary of Costs Attributable to Level III Events Including Declared Emergencies 1995-2021 ($2021)



Q. What do these two graphs indicate?

A. They reveal that Events tend to occur in clusters and that they are increasing in cost over time. They rebut AWEC's incorrect assertions that "PGE's analysis demonstrates that the distribution of Level III storm costs has been relatively uniform over time"[4] and that "Level III storm costs actually declined over the 27-year period."[5] As we stated in PGE Exhibit 1400 regarding non-declared-emergency Events (PGE Figure 1), "57% of the total nominal costs

[3] For Figure 2 and this discussion, PGE is only including restoration O&M costs but not capital-related costs. This is not to say that the capital-related costs are not applicable to the UM 2115 (wildfire) or UM 2156 (ice storm) deferrals, but rather they are omitted here for a consistent comparison of O&M costs in 2021 dollars across all events.
[4] AWEC/300, Mullins/21.
[5] AWEC/300, Mullins/21

and 50% of the real costs have been incurred in just the past eight years of the 26-year period."[6] Regarding all Events (PGE Figure 2), 80% of the total nominal costs and 74% of the real costs have been incurred in just the past eight years of the 27-year period. This is <u>not</u> indicative of costs being relatively uniform or declining over time.

Q. Why is it appropriate to include the declared emergencies when analyzing Event trends if the Commission has established a separate mechanism for those Events?

A. By definition, the 1995, 2020, and 2021 declared emergencies meet the criteria for Events, and as such, they should be part of any analysis or discussion of changing conditions due to climate change. We also note that there are no objective criteria regarding which Events constitute a declared emergency. It is very possible that a severe Event will not be designated a declared emergency, just as it is possible that a declared emergency will not meet the criteria for an Event (as occurred recently on January 3, 2022). Although it is appropriate to include declared emergencies in any analysis of Event trends, we generally agree that recovery for declared emergencies should be addressed using the pre-filed emergency deferral process and should not be: 1) included in the 10-year average of costs with which to calculate the Mechanism annual accrual; or 2) applied against the Mechanism's Level III Reserve account (Reserve).

Q. Does the existence of pre-filed emergency deferral accounts impact PGE's request to improve the Mechanism?

A. No. The Mechanism remains necessary and relevant after the adoption of pre-filed deferrals for declared emergencies. As we just explained, PGE will continue to experience major outage Events that are not declared emergencies, because there are no objective criteria for

[6] PGE/1400, Tooman-Batzler/41.

declaring an emergency. The Commission's adoption of the pre-filed emergency deferral process—at Staff's recommendation—shows the Commission's commitment to aligning recovery incentives with expedited service-restoration efforts. PGE's revisions to the Mechanism better implement this policy.

Q. Do PGE Figures 1 and 2 help to address Staff's analyses that lead to erroneous conclusions?

A. Yes. Staff provides two analyses that lead to erroneous conclusions. The first is reflected in Figure 1 of Staff Exhibit 2700. There, Staff calculates and plots the average cost of non-emergency Events based on PGE Exhibit 1404 and concludes that "Because decreasing restoration costs per storm approximately offset increasing storm frequency, *total* Level III outage restoration costs have not been trending upwards over time"[7] (emphasis added). The second Staff analysis repeats their Mann-Kendall statistical test using expanded data back to 1996, from which Staff concludes that "Notwithstanding the longer time period, the statistic fails to reject the null hypothesis that there is no trend" of increasing Event cost.[8]

Q. How do you respond to Staff's first analysis regarding average Event costs?

A. Average cost per Event does not provide a meaningful measure of intensity. Consider 2014 through 2017, when Events caused PGE to incur a significant amount of restoration costs. Those events and magnitude of damage depleted PGE's Level III Reserve (Reserve) balance and resulted in PGE filing for a deferral for 2017 costs. For the January 2017 Event in particular, CUB observed that "The January 2017 snowstorm was characterized by the National Weather Service as a one in 25-year storm."[9] Staff, however, averages two large

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[7] Staff/2700, St. Brown/4.
[8] Staff/2700, St. Brown/5.
[9] UE 335; CUB/200, Gehrke-Jenks/25.

Events from 2017 with two much smaller Events to derive an average for 2017 that provides no indication of how much damage the 2017 Events did in total. Staff's analysis is analogous to a person who has one hand in boiling water and one hand in ice water and is told that on average, the temperature of their hands is fine. Furthermore, if we include the declared emergency Events in Staff's analysis, as in PGE Figure 2, then evidence of increasing intensity is more pronounced. In summary, Staff Figure 1 is inaccurate and misleading for evaluating Event trends for indications of climate change.

Q. If averaging Event costs is inappropriate, why use a 10-year average to develop the Level III accrual?

A. We do so because Events are too irregular to forecast in any meaningful way. As an alternative to forecasting, we use the 10-year average of actual costs but recognize that it has limitations, which PGE's proposed revisions to the Mechanism would help to mitigate.

Q. Staff and AWEC believe the 10-year average fairly captures the prudently incurred costs and any increases that may occur so that allowing a negative balance is unnecessary. Do you agree?

A. No. The 10-year average captures prudently incurred costs but its resultant accrual has been behind subsequent Events, which has denied PGE recovery of significant Event costs. If we consider PGE Figures 1 and 2, we see that historically, Events tend to come in clusters, where periods of relatively mild conditions are followed by periods of more severe conditions. Under these circumstances, subsequent Events will cause damage that will be subject to inflation and expansion to PGE's service area and/or infrastructure that will <u>not</u> be captured by the historical average.[10] This effect is depicted in Figure 3 below, which shows how an identical Event

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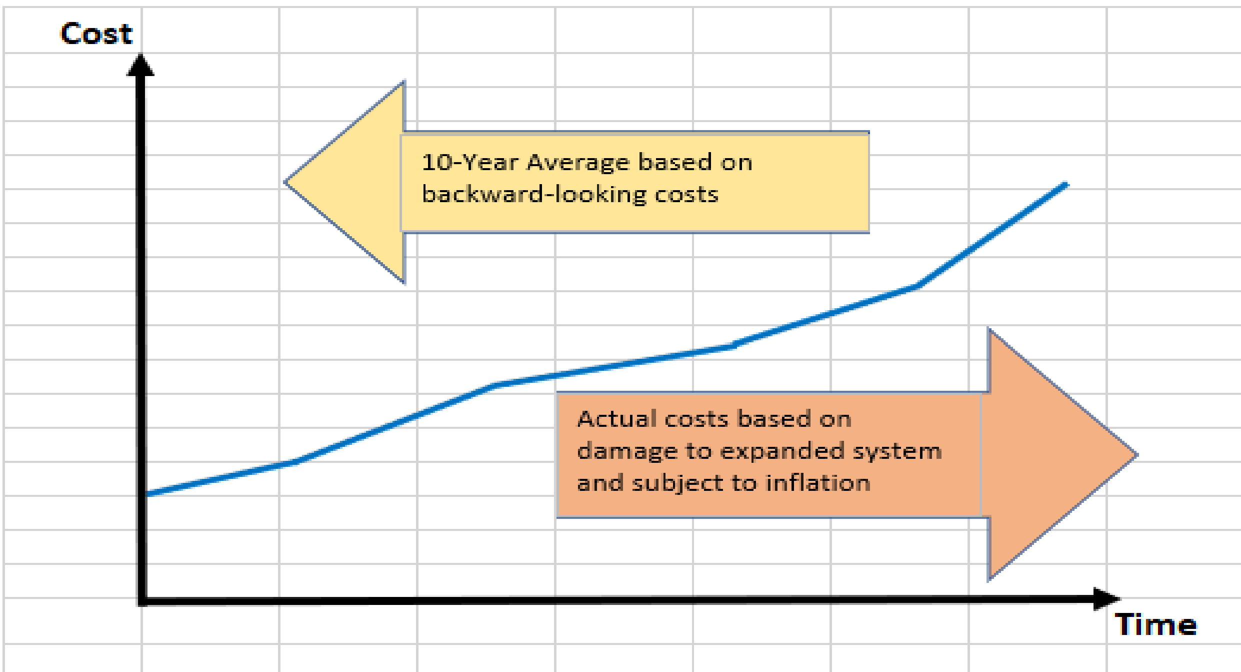
[10] For example, the current level of inflation, which is the highest in approximately 40 years, is not in the 10-year average used to calculate the Level III accrual for this GRC.

occurring over time would result in increasing restoration cost based on an expanding system and inflation. Although the cost of the subsequent Events will continue to be higher (even absent effects from climate change), the 10-year average will only look backward at lower-cost Events.

Figure 3
Example of Costs from the Same Event Over Time



In addition, periods of mild conditions will allow the Reserve to increase, but will also significantly pull down the 10-year average on which the accrual is based, so that it will not accurately reflect the subsequent Events or cluster of Events. In fact, this is what occurred in 2010-2013 (mild conditions) followed by 2014-2017 (severe conditions).[11] This is also reflected in the current accrual, which is declining from \$3.8 million to \$3.5 million due to the recent period of milder conditions (and the exclusion of declared-emergency event costs).

[11] By 2017, the 2014-2016 Events had depleted the \$6 million reserve (from 2011-2013) and \$6 million additional accruals (from 2014-2016) so that the \$2 million accrual in 2017 was inadequate to offset the \$11.4 million in Event costs.

If the pattern of PGE Figure 1 continues, the accrual and Reserve will likely be insufficient when the next cluster of Events occur. Staff and AWEC each implicitly acknowledge that the 10-year average is not adequate. Staff states "To help the Company with cost recovery, Staff's Opening Testimony proposed to annually reset the 10-year average to ensure that if costs rise the Company does not have to wait until its next general rate case to reset the amount recovered for Level III outage recovery costs."[12] This supports PGE's position that the 10-year average, as currently functioning, does not adequately capture the impacts of climate change or increasing costs. AWEC appears to agree with our conclusion and contradicts itself by stating that "The accelerating effects of climate change on storms, for example, cannot readily be isolated to a period of less than 10 years, rendering the 10-year average inadequate."[13] In summary, the 10-year average does not fairly capture the prudently incurred costs because it does not capture increases that will likely occur.

Q. How do you respond to Staff's updated Mann-Kendall test?

A. In supporting its emphasis on the Mann-Kendall test results, Staff asserts that "total cost is the appropriate variable to consider since, as just described, frequency of storms and cost per storm approximately offset each other."[14] We disagree that it is appropriate to focus only on total cost when examining changing event patterns due to climate change. PGE has provided detail that indicates the changing qualitative nature of Events as well as increasing frequency and increasing total costs. As we have been careful to observe, PGE is providing evidence or indications of climate change as revealed by impacts to our Events over the past 27 years. Our

[12] Staff/2700, St. Brown/7-8.
[13] AWEC/300, Mullins/21.
[14] Staff/2700, St. Brown/5.

evidence demonstrates meaningful trends that tend to conform to the information provided by the Fourth National Climate Assessment.[15]

In addition, Staff's Mann-Kendall analysis excludes declared emergency events. As we explained above, these events should be included in the analysis of Event trends, even though the 2020 and 2021 declared-emergency events are not covered by the Mechanism.

Q. Please summarize how you refute Staff's Mann-Kendall analysis.

A. We do so by presenting as much information as is available on the topic and showing that in total, the data: 1) supports PGE's position that event patterns are changing; and 2) indicates that the current structure of PGE's Mechanism is not adequate for the Event pattern and intensity PGE has experienced and should be reconsidered. Staff, however, appears to rely on a single calculation that presents only one statistic with which to evaluate something as complex as climate change and how it should be addressed. We believe this is inadequate and uninformative.

B. Wildfires

Q. Why does CUB argue that wildfire-related costs are inappropriate to include in the recognized Events or Mechanism?

A. CUB states that "There is no evidence that wildfire was contemplated when this mechanism was established in 2010. The Company appears to be parsing the language in a way it was not intended, and its proposal to include wildfire-related costs in the Level III outage restoration mechanism should be denied."[16]

Q. Do you agree with this statement?

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[15] Fourth National Climate Assessment, Chapter 24, at https://nca2018.globalchange.gov/chapter/24/. See summary in PGE Exhibit 800, Section IV, Part A.
[16] CUB/500, Gehrke/15.

A. No. As noted in PGE Exhibit 800, "When Commission Order No. 10-478 first approved PGE's Level III recovery mechanism, it was originally viewed as relating to storms, or more specifically, winter storms."[17] However, at that time as now, the established criteria define an Event, not its cause. The fact that wildfires were not specifically contemplated does not mean they are excluded, any more than a summer wind event would be excluded because it is not a winter storm. Instead, it means that changing conditions due to climate change are resulting in a greater variety of Events, as PGE has demonstrated. These changing conditions and recent events are undoubtedly what the Commission recognized in issuing Order 21-259, which allows utilities to establish pre-filed emergency deferral accounts.

Q. Do any other Parties comment on this issue?

A. Yes, Staff agrees that the Mechanism covers wildfires and states that "The Company makes a good point. Although Level III outage restoration costs are not currently trending upwards, they could in the future due to wildfires."[18]

[17] PGE/800, Bekkedahl-Jenkins/65-66.
[18] Staff/2700, St. Brown/7.

III. Risks and Incentives

Q. Given the evidence that climate change appears to be causing a change in the nature of Events and likely causing an increase in frequency, intensity, and/or cost of associated restoration efforts, what other issues do Parties raise with regard to PGE's proposal?

A. Parties raise the issue of risk and incentives. CUB addresses this by stating that "Currently, the risk of increased Level III restoration costs between general rate cases lies with PGE, who manages its wires system and is therefore best equipped to manage this risk. PGE's proposal places a significant portion of the cost risk on the customers, and significantly limits incentive for PGE to control costs comprehensively."[19] Staff also addresses this issue by stating that "Staff believes that PGE's incentive to harden its system is strongest when Level III outage expenses are set on a forward-looking basis, rather than trued-up after the fact"[20] (i.e., by allowing the accrual balance to go negative).

Q. How do you respond?

A. First, we disagree with Staff's assertion because the 10-year average and associated accrual are always backward looking, and as discussed above, their amounts are most likely to be behind the cost for the next cluster of Events. Second, the issues of risk and incentives relate to both costs that can be controlled and costs that are beyond PGE's control. Costs that can be controlled relate primarily to PGE's efforts to address external, geographic factors that impact electrical infrastructure and account for approximately two-thirds of all outages. As stated in PGE Exhibit 800, "PGE is also proactively investing in its infrastructure to mitigate the impact of Level III event damage before it occurs but also to enhance the resilience and

[19] CUB/500, Gehrke/13.
[20] Staff/2700, St. Brown/6.

reliability of the T&D system ... Further, we are doing so based on a rational approach and without regard to the mechanism under which Level III restoration costs are recovered. In other words, a change in the mechanism will create neither an incentive nor disincentive to continue this work."[21]

Q. How do you address costs that are beyond PGE's control?

A. Costs that cannot be controlled relate primarily to the severity of the Event, the amount of damage it produces, and the amount of resources and effort needed to restore service as quickly as possible. With respect to these costs, PGE Exhibit 800 stated "When Level III events occur, PGE makes every effort to restore power as quickly as possible. This is expected of us by customers, by the Commission, and by ourselves. PGE has always maintained this commitment and will continue to do so, regardless of how some or all of those costs are recovered."[22] In addition, "PGE does not and would not engage in limiting its Level III-related costs by delaying restoration to incur significantly less overtime and contractor hours. Conversely, PGE has no incentive to over-apply resources and costs to a Level III event."[23]

Q. What does this specifically mean?

A. Regarding costs that can be controlled, PGE is already being systematic and rigorous about its efforts to harden the system and comprehensively control its costs. Unfortunately, there is only so much that can be proactively done to prevent damage from Events given geography and overhead systems; capital constraints; other resource demands for reliability, resiliency, and safety; acceptable limits of rate increases; etc. This means that there will always be damage from Events, and PGE will always incur costs that are beyond its control, no matter

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[21] PGE/800, Bekkedahl-Jenkins/70.
[22] PGE/800, Bekkedahl-Jenkins/68.
[23] PGE/800, Bekkedahl-Jenkins/68.

how much PGE is incented to harden its system and control costs. As a result, the issue is ultimately about the recovery of prudently incurred costs.

Q. How does this address CUB's and Staff's concerns regarding risk?

A. In response to Commission Order 19-129, PGE's proposal includes asymmetric cost sharing as part of the mechanism. Whenever the Reserve has a negative balance, PGE would absorb 10% of the costs of all Events until the balance is positive again. There is no corresponding sharing of benefit if the Reserve has a positive balance. Because Parties appear to be more concerned with a growing negative balance, PGE will also absorb 10% of the costs when the Reserve balance exceeds the proposed cap of negative $12.0 million. We believe this is a reasonable sharing proposal for prudently incurred costs.

IV. Summary and Conclusions

Q. Please summarize your testimony.

A. First, as noted in PGE Exhibit 1400, "We appreciate Staff's and CUB's offers for revising PGE's Level III mechanism. We believe these proposals reflect the understanding that climate change is a reality and that there is much complexity and uncertainty regarding its impacts on Level III events."[24] CUB and Staff continue to support their proposed revisions to the Mechanism. Second, we believe that PGE has provided sufficient evidence to satisfy the Commission's request for information as stated in Order 19-129. This information indicates that with the impacts of climate change: 1) the types of Events PGE is experiencing are changing over time; and 2) there appears to be an increasing frequency and intensity of Events. In contrast, we believe that Staff and AWEC have provided no evidence that a negative balance is unwarranted or harms customers.

Q. Please summarize your request of the Commission.

A. Based on the evidence and testimony provided in this case, we request that the Commission approve our proposed revision to the Mechanism, which we summarize as follows: The amount collected in base prices will continue to be based on the ten-year average of Level III restoration costs, which will accrue to a reserve account for use against future Level III events. If Level III restoration costs in a given year exceed a positive reserve balance, the reserve account will allow a negative balance to be maintained until a positive balance is restored by collections exceeding costs based on the following criteria:

- For every year that results in a negative balance, the actual Level III restoration

[24] PGE/1400, Tooman-Batzler/43.

costs that are applied to that negative balance[25] will be shared 90% by customers and 10% by PGE (i.e., 90/10 sharing, where 90% of the costs will be applied to the balancing account and 10% will be absorbed by PGE)

- If the balancing account exceeds a $12 million positive or negative balance, PGE will amortize the excess amount by either collection from (negative balance) or refund to (positive balance) customers based on a 90/10 sharing of the excess amount.

Q. Do you still believe that the combination of CUB's and Staff's proposal represents a reasonable alternative for the Commission to consider if the Commission is not inclined to adopt PGE's proposal?

A. Yes. As noted in PGE Exhibit 1400, "Although we do not advocate for an alternative to PGE's initial proposal, we note that CUB's proposal of a balancing account and specified hard caps coupled with Staff's proposal of annual updates represents a reasonable alternative for the Commission to consider if the Commission is not inclined to adopt PGE's proposal."[26]

Q. Does this conclude your testimony?

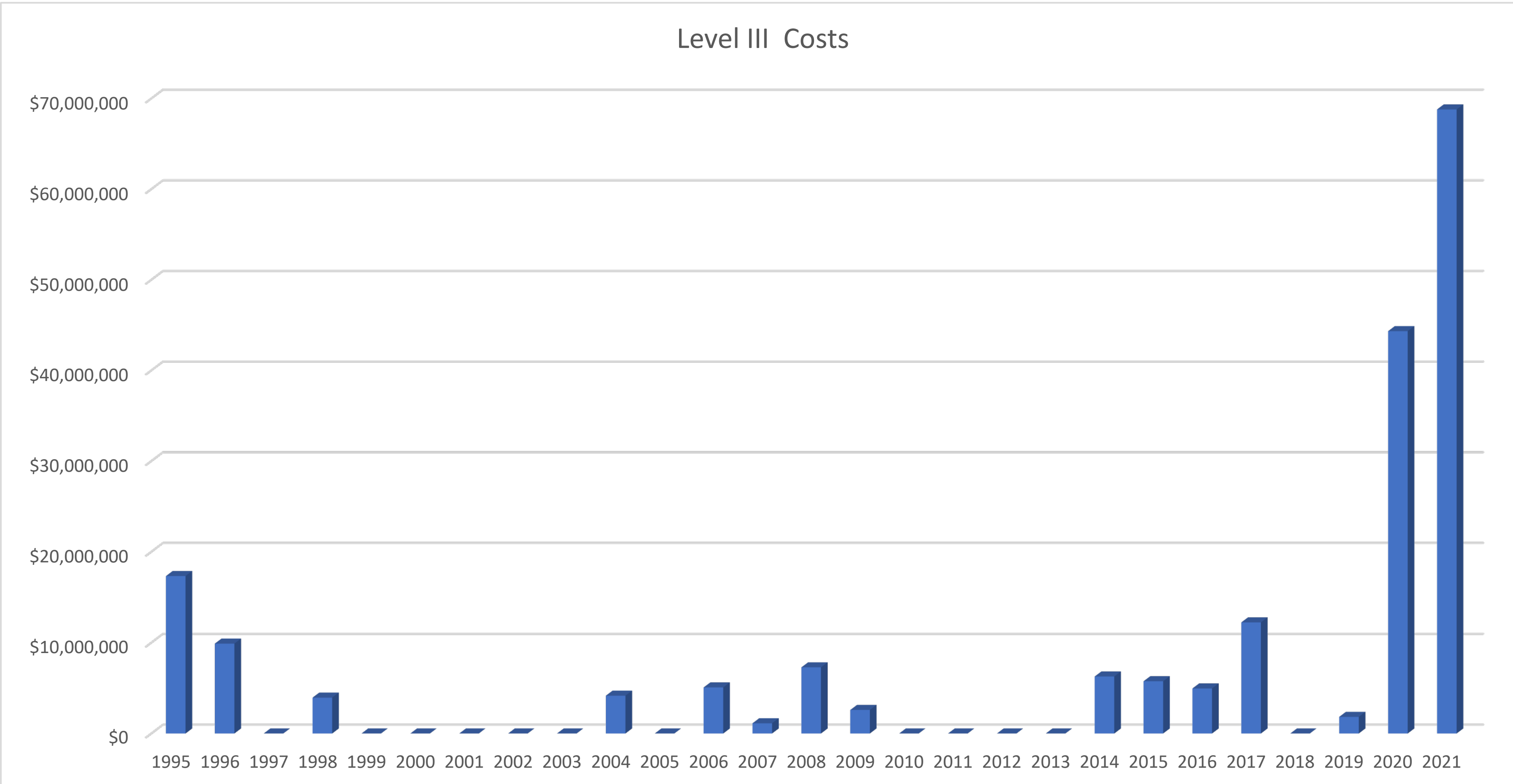
A. Yes.

[25] If the Level III restoration costs exceed a positive reserve balance, only the costs that are applied to the negative balance will be subject to the sharing. The costs that take the balance to zero will not be subject to sharing. If the balance is already negative, all Level III restoration costs will be subject to the sharing percentages.
[26] PGE/1400, Tooman-Batzler/43.

List of Exhibits

Summary of Costs Attributable to Level III Events
1995-2021

	With Declared Emergencies				Without Declared Emergencies		
Year (a)	**Level III Costs (b)**	**Inflation (c)**	**$2021 Costs (d)**	**Year (a)**	**Level III Costs (b)**	**Inflation (c)**	**$2021 Costs (d)**
1995	**$10,000,000**	2.82%	$17,327,557	**1995**	**$0**	2.82%	$0
1996	$5,880,000	2.95%	$9,896,388	1996	$5,880,000	2.95%	$9,896,388
1997	$0	2.29%	$0	1997	$0	2.29%	$0
1998	$2,438,440	1.56%	$3,950,452	1998	$2,438,440	1.56%	$3,950,452
1999	$0	2.21%	$0	1999	$0	2.21%	$0
2000	$0	3.36%	$0	2000	$0	3.36%	$0
2001	$0	2.85%	$0	2001	$0	2.85%	$0
2002	$0	1.58%	$0	2002	$0	1.58%	$0
2003	$0	2.28%	$0	2003	$0	2.28%	$0
2004	$2,976,869	2.66%	$4,161,502	2004	$2,976,869	2.66%	$4,161,502
2005	$0	3.37%	$0	2005	$0	3.37%	$0
2006	$3,869,486	3.22%	$5,069,837	2006	$3,869,486	3.22%	$5,069,837
2007	$886,621	2.87%	$1,129,243	2007	$886,621	2.87%	$1,129,243
2008	$5,936,058	3.81%	$7,282,623	2008	$5,936,058	3.81%	$7,282,623
2009	$2,106,514	-0.32%	$2,592,672	2009	$2,106,514	-0.32%	$2,592,672
2010	$0	1.64%	$0	2010	$0	1.64%	$0
2011	$0	3.14%	$0	2011	$0	3.14%	$0
2012	$0	2.07%	$0	2012	$0	2.07%	$0
2013	$0	1.47%	$0	2013	$0	1.47%	$0
2014	$5,623,875	1.62%	$6,274,099	2014	$5,623,875	1.62%	$6,274,099
2015	$5,161,601	0.12%	$5,751,410	2015	$5,161,601	0.12%	$5,751,410
2016	$4,504,081	1.26%	$4,956,282	2016	$4,504,081	1.26%	$4,956,282
2017	$11,351,424	2.14%	$12,229,557	2017	$11,351,424	2.14%	$12,229,557
2018	$0	2.44%	$0	2018	$0	2.44%	$0
2019	$1,772,198	1.81%	$1,830,656	2019	$1,772,198	1.81%	$1,830,656
2020	$43,345,470	1.00%	$44,332,275	2020	$0	1.00%	$0
2021	$68,788,380	2.28%	$68,788,380	2021	$3,594,072	2.28%	$3,594,072
Totals	**$174,641,017**		**$195,572,934**	**Totals**	**$56,101,239**		**$68,718,793**
Last 8 years as % of total	80%		74%	Last 8 years as % of total	57%		50%


Level III Costs
$70,000,000
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$0
1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021


Level III Costs
$14,000,000
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$0
1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Fee Free Bank Card

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

John McFarland
Allison Rowden

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is John McFarland. I am Vice President and Chief Customer Officer. My qualifications were previously provided in PGE Exhibit 500.

My name is Allison Rowden. I am a Customer Service Manager primarily responsible for Credit and Payments. My qualifications appear at the end of this testimony.

Q. Ms. Rowden, do you adopt Mr. McFarland's prior testimony in this matter as your own?

A. Yes. I adopt Mr. McFarland's Direct Testimony (PGE/500, Bekkedahl – McFarland) filed on July 9, 2021 and Mr. McFarland's Reply Testimony and Exhibits (PGE/1700, Bekkedahl – McFarland) filed on December 2, 2021.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the remaining issues and proposed adjustments raised by the Staff of the Public Utility Commission of Oregon (OPUC Staff or Staff) regarding PGE's Fee Free Bank Card (FFBC) program. Specifically, we continue to rebut Staff's proposed $1,500 monthly cap on non-residential FFBC payments and provide support for why a higher limit is necessary in order to provide this option to all Schedule 32, small non-residential customers. We also demonstrate that PGE's revised marginal cost study allows for Schedule 83, large non-residential customers to utilize the program without shifting costs to other rate schedules. Additionally, we rebut Staff's new proposal to make the non-residential FFBC program temporary in nature, as customers had asked for this optionality prior to the COVID-19 pandemic and PGE followed consistent policies and procedures in coordination with our Supply Chain department to ensure that the cost of the program is competitive. Finally, we propose, as an alternative to our non-residential FFBC program cap, reducing the maximum aggregate customer payment per account from $15,000[1] down to $5,000 per billing cycle.

Q. How is your testimony organized?

A. In Section II, we respond to Staff's proposed adjustment to FFBC as well as PGE's counter proposal. In Section III we provide concluding remarks and qualifications.

[1] PGE initial proposal was to allow for a maximum of $5,000 per payment up to three times a billing cycle.

II. Fee Free Bank Card

Q. What is Staff's current position on FFBC?

A. Consistent with their opening testimony (Staff Exhibit 400), Staff proposes "reduc[ing] the transaction limit from PGE's current terms for nonresidential customers from $5,000 three times a billing period to $1,500 per billing period."[2] However, Staff now agrees that PGE's adoption forecast of 5% is reasonable, as the actual month over month adoption rate PGE has experienced for the non-residential program is above 9%. Staff also now agrees with PGE's revised method for allocating the FFBC program costs to customers' specific schedules based on the proportion of revenues collected using the FFBC program. Staff continues to be "critical of PGE pointing to terms defined in a contract the Company entered into without Commission notification or review" and notes that "PGE should have brought [the contract] forward to the Commission for approval prior to offering such a service."[3]

Additionally, based on their unsupported opinion that the terms of PGE's payment processor contract are "potentially excessive"[4] and that the changes due to COVID-19 are temporary in nature, Staff includes a new recommendation that PGE should "terminate [the program] upon the expiration of the COVID-19 related state of emergency."[5] Finally, Staff raises new concerns regarding Amazon Pay fees. This issue, however, was settled in the Third Partial Joint Stipulation, filed with the Commission on January 18, 2022, and is therefore no longer relevant to this case.

Q. What is PGE's current non-residential transaction amount and volume limit for a FFBC?

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[2] Staff/2300, Scala 7
[3] Staff/2300, Scala/8
[4] Staff/2300, Scala/9
[5] Staff/2300, Scala/15

A. Currently, a non-residential customer can make up to a $5,000 payment a total of three times a month per PGE account using the FFBC option. The payment limit is designed to provide up to 99% of Schedule 32 customers the ability to pay off their monthly balance in one transaction. The allowance of up to three payments per month provides flexibility to customers who choose to make several payments a month.

Q. Why do some customers make multiple payments per month?

A. PGE customers sometimes have multiple service accounts consolidated on one PGE account, so allowing multiple payments within a month provides payment flexibility in cases where customers pay service accounts via different debit and credit cards. The ability to make multiple payments within a month also provides customers the ability to make additional FFBC payments to pay off arrears.

Q. Does PGE have an alternative proposal for the FFBC monthly transaction limit that continues to provide flexibility for customers?

A. Yes. To limit the total cost of the program while continuing to provide the opportunity for as many Schedule 32 customers as possible to participate, PGE proposes to cap the monthly aggregate FFBC non-residential customer payment at $5,000. However, customers will be allowed to make more than one payment per month. Thus, the individual payment amount and volume limit will be set by PGE, but per cycle maximum amount will not be allowed to exceed $5,000.

Q. How does a $5,000 limit compare to Staff's proposal?

A. A monthly limit of $5,000 allows 98.94% of Schedule 32 customers to make a payment using the FFBC. Staff's proposal of $1,500 limit allows 93.51% of payments to be made via FFBC. While this percentage difference may seem small, on average, this change would prevent approximately 5,000 monthly Schedule 32 accounts from fully paying their bill using PGE's FFBC program. Table 1 provides a summary of Schedule 32 customer bills.

Table 1^
(All bills for Schedule 32 between January 2019 and October 2021)

Bill Range	Total Bills	Monthly Average	Percent of Bills
$0 - $1,500	2,966,664	87,255	93.51%
$0 - $5,000	3,138,832	92,318	98.94%
Total	**3,172,483**		

^Detail provided in PGE's Response to OPUC DR 938, provided here as PGE Exhibit 2502

Q. Staff states that applying their $1,500 transaction limit "would still allow for approximately 94 percent of all nonresidential transactions, and 99 percent of Schedule 32 transactions."[6] Is this accurate?

A. No. Staff's analysis only accounts for existing FFBC transactions, not all non-residential customer bills. When looking at all non-residential customers and not just those who have previously participated in the FFBC program, Staff's proposed limit would allow 87%[7] of non-residential transactions (other than schedule 32) and 93.5%[8] of Schedule 32 transactions to be made via FFBC.

Q. Is there a good reason for limiting the FFBC program to Schedule 32 customers?

A. No. While this program was initially implemented to alleviate burdens for small business customers, other customer schedules have taken advantage of and value this offering. Since the launch of this offering to non-residentials customers, on April 7, 2020, PGE has seen utilization of the program across a wide range of schedules[9] indicating that customers want this payment option. Additionally, PGE modified its customer service marginal cost study

[6] Staff/2300, Scala/10
[7] See PGE's Response to OPUC DR 939, provided here as PGE Exhibit 2501
[8] See PGE's Response to OPUC DR 938, provided here as PGE Exhibit 2502
[9] See PGE's Response to OPUC DR 941, provided here as Confidential PGE Exhibit 2503C

such that this program now equitably allocates program costs, avoiding subsidization across customer classes. In fact, Staff agrees with this approach, stating that "PGE's proposed methodology follows cost causation principles such that the allocation would have FFBC costs recovered from the customer class and schedule where they are incurred."[10] Therefore, if customers, in classes other than Schedule 32, want to use the FFBC program, subject to the program caps, they should be allowed to participate, as the program costs are appropriately allocated to their rate schedules.

Q. How has PGE modified the allocation of FFBC program costs?

A. PGE recognized the need to change the allocation methodology of FFBC program, as previously this program was available only to residential customers. In our reply testimony (PGE Exhibit 2200), PGE revised its marginal cost study so that the allocation of costs is based upon the total payment amounts made by each customer schedule using the FFBC program. Staff raised a concern and stated that "Schedule 32 customers represented around [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]." Staff's analysis is correct in the assessment that Schedule 32 customers have a greater number of transactions with a smaller percentage of costs. However, PGE's rate spread proposal for the FFBC program now "allocate[s] costs to each customer class based on the percentage of FFBC costs incurred by that customer class."[11] Thus, as FFBC costs are not allocated based on the number of transactions and instead are allocated based on revenues collected via the FFBC program, each customer class pays for costs incurred by that schedule. As stated in PGE Exhibit 2200, "as a result of this change, in 2022, customer classes with the largest allocation of FFBC fees will be customers in Schedules 32

[10] Staff/2300, Scala/22
[11] PGE/2200, Macfarlane-Tang/25

and 83."[12] PGE Exhibit 2202 provided the detailed work paper with this revised method of cost allocation.

Q. Does PGE agree that the non-residential FFBC program should be temporary?

A. No. Although PGE implemented this program during the pandemic, customers have sought this flexibility for years as the way that businesses work has permanently shifted.[13] In fact, over the last several years, businesses have been shifting to digital operations. The pandemic simply accelerated this trend. Many non-residential customers requested PGE offer FFBC payments prior to the pandemic and the need only grew when more customers were no longer centrally located at the workplace, making it more difficult to issue a company check. Additionally, for many businesses, checks require two people to be on location for signatures, and social distancing guidelines accelerated the need to provide easy and flexible alternatives. Although the shift of work from home was initially believed to be temporary, it is now widely accepted that there have been significant, permanent changes to the way that businesses work. To that extent, PGE believes that the non-residential FFBC program should become a permanent business offering. While Staff is correct that customers can pay their bills electronically through Automated Clearing House (ACH) payments, some customers are unable to use this option due to technical limitations on their end and, in general, ACH payments can be more difficult to set up. PGE's FFBC program is an easier option for customers and the over 9% adoption rate is a clear indication that customers want this payment option.

Q. Did PGE have a requirement to notify Staff of this offering?

[12] PGE/2200, Macfarlane-Tang/26
[13] See Exhibit 2504 for customer comments and PGE customer satisfaction scores.

A. Yes. Pursuant to Commission Order No. 15-356, PGE agreed "to notify Staff no less than forty-five days prior to launching a commercial fee free bankcard payment program."[14] However, due to the urgency of the shift to work from home during the early stages of the pandemic, PGE was not able to provide the full forty-five-day notice but did provide notice to Staff shortly after all PGE employees began working from home in March.[15] In addition to the phone call in March, PGE provided an update to OPUC's manager of Consumer Services, including a multi-page document via email on May 12, 2020 discussing recent changes made along with support for why we made the changes.[16] This document specifically mentions that PGE was planning on providing the FFBC option to non-residential customers on a permanent, post-pandemic basis. This indication of a potential permanent offering was almost six months prior to PGE formally amending its FFBC contract to include the current commercial FFBC rate.[17] Additionally, consistent with traditional ratemaking principles, PGE has included and provided support for the costs of this program within its first general rate case proceeding program expansion.

Q. Staff repeatedly makes statements in its testimony suggesting that PGE failed to obtain a required approval for extending this program. Was there a requirement that PGE seek approval prior to offering this option to customers?

A. No. As we state above, PGE was only required to notify Staff prior to offering the program. There were no other requirements. Staff argues that because this contract impacts customer prices, PGE should have sought Commission approval prior to offering the service, suggesting

[14] Commission Order No. 15-356, page 5.

[15] As discussed in PGE's Response to OPUC DR 946, PGE notified OPUC's Energy Rates, Finance and Audits Administrator via a phone call in March 2020 and the commercial FFBC program began April 7, 2020.

[16] Provided here as Confidential PGE Exhibit 2505C

[17] PGE's Response to OPUC Data Request No. 852, Attachment 852-A provides the current FFBC contract and amendments, which are proved here as Highly Confidential PGE Exhibit 2506HC

that PGE somehow intentionally skirted regulatory process regarding this program. In fact, PGE negotiates new and existing contracts regularly, following consistent policies and procedures in coordination with our Supply Chain department, and there is no regulatory requirement that PGE seek approval prior to execution of a contract of this size or nature. This would not only be impractical, but unreasonable and inefficient. While we recognize that the required notice was provided less than 45 days in advance, there were extenuating circumstances because of the COVID-19 pandemic and PGE's need to rapidly respond to customer needs during this time. However, a notice requirement does not equate to the program approval requirement Staff suggests we needed. Consistent with traditional ratemaking principles, PGE assumed the risk of entering into this contract with a supplier, utilized our experience and expertise to negotiate favorable contract terms after running a competitive solicitation, and are now justifying that decision and seeking recovery within a general rate case proceeding of a prudently executed contract that benefits customers.

Q. Staff claims that PGE's FFBC program was "restricted to residential customers."[18] Does PGE agree the program was "restricted"?

A. No. This is simply incorrect. PGE's current rate structure was established based upon a FFBC program for residential customers only. However, there has never been a preclusion or restriction on PGE's ability to offer this service to non-residential customers. As we discuss above, the only directive to PGE regarding a commercial FFBC program is the notice requirement contained in Commission Order No. 15-356. This directive is clearly not a restriction.

[18] Staff/2200, Muldoon/4

Q. Staff claims that the terms of PGE's FFBC processor contract are potentially excessive. How do you respond?

A. Staff's argument, relying on a cursory review of other utility fees, is not sufficiently supported and is unconvincing. The information provided by Staff is limited at best and does not provide nearly enough detail for an apples-to-apples comparison between services and total program cost. Additionally, there are no contract terms, or a price provided for the only *comparable* utility Staff includes in their testimony who also provides a FFBC option to non-residential customers; a utility who recovers the cost of their non-temporary commercial FFBC program through Oregon Commission authorized prices.

Q. How does PGE ensure that contracts entered into by the business are least cost and least risk?

A. PGE has policies in place that leverage the expertise of our Supply Chain department and specifically, for contracts exceeding $50,000, a competitive solicitation must be conducted.[19] As such, prior to entering into an agreement with our current payment processor, PGE's Supply Chain department and business team requested and received proposals from numerous national payment processors that included both price and functionality. As part of negotiations, PGE secured the lowest residential and commercial fees possible. Due to the high volume of residential transactions, the residential fee had a higher priority, however, PGE was still able to negotiate a competitive rate for non-residential customers that was lower than offers from certain other payment processors. Some vendors were willing to offer a lower non-residential rate at the expense of the residential rates, however, PGE did not want residential customers to bear the cost of the commercial customers. Therefore, PGE entered

[19] To see PGE's Supply Chain Policy, See PGE's Response to OPUC DR 852, provided here as Confidential PGE Exhibit 2507C

into and finalized the contract that was provided in PGE's response to OPUC Data Request No. 852.[20] Table 2 below provides the combined expected results for residential and commercial customers of PGE's FFBC contract negotiations as presented[21] to the Customer Service Business Group. [BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. How do you respond to Staff's argument that PGE's exclusivity contract term resulted in a non-competitive contract?

A. Exclusivity clauses are standard language in financial contracts as they provide certainty and stability to the service provider. Additionally, as part of final contract negotiations, PGE secured a reduced duration for exclusivity, allowing PGE more flexibility to seek and secure the best price and offering for customers in the future, should the market change.

Q. How does PGE respond to Staff's testimony regarding Amazon Pay?

A. Staff improperly raises an issue that has been stipulated to and resolved through the Third Partial Joint Stipulation, to which Staff was a signatory. As such, PGE does not believe Staff's arguments on the subject should be considered in this docket and thus we will not be responding to them at this time.

[20] Provided here as Highly Confidential PGE Exhibit 2506HC
[21] Presentation slides provided here as Highly Confidential PGE Exhibit 2508C

III. Conclusion and Qualifications

Q. Please summarize your position regarding issued identified by Parties.

A. We recommend the Commission:

- Accept PGE's alternate proposal to allow non-residential customers to participate in the FFBC program to pay bills up to $5,000 per billing cycle. The individual payment amount and volume limit will be set by PGE to allow customer flexibility, however, per cycle maximum amount will not exceed $5,000 per PGE account. This proposal would allow up to 98.9% of Schedule 32 customers to participate in the FFBC program.
- Reject Staff's latest proposal to terminate the FFBC for non-residential customers when the State of Emergency related to Covid-19 is lifted. The pandemic has led to a significant and permanent shift to the ways that businesses operate, and current adoption rates suggest that this offering is welcome and valued by our customers. Additionally, the new allocation method of the FFBC costs provides that each customer class is appropriately allocated program costs, eliminating cross subsidization.
- Dismiss staff's claim that PGE's non-residential contract with our payment processor was "potentially excessive,"[22] as PGE holistically negotiated a competitive price for both residential and commercial customers through a competitive solicitation using the expertise and leverage of our Supply Chain organization.

Q. Ms. Rowden please describe your qualifications.

A. I received a Bachelor of Arts Degree in Liberal Studies with minors in Business and

[22] Staff/2300, Scala/9

Psychology from Eastern Oregon University. I joined PGE in April of 1998 and have served in multiple management positions in customer service since 2001, Most recently I am the Manager of Customer Service in Credit and Payments.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
2501	PGE's response to OPUC Data Request No. 939, Attachment A
2502	PGE's response to OPUC Data Request No. 938, Attachment A
2503C	PGE's response to OPUC Data Request No. 941, Attachment A
2504	PGE's Customer Comments and Satisfaction Rating
2505C	PGE's FFBC Email to Staff
2506HC	PGE's response to OPUC Data Request No. 852, Attachment A
2507C	PGE's response to OPUC Data Request No. 852, Attachment B
2508HC	Customer Service Business Group Presentation

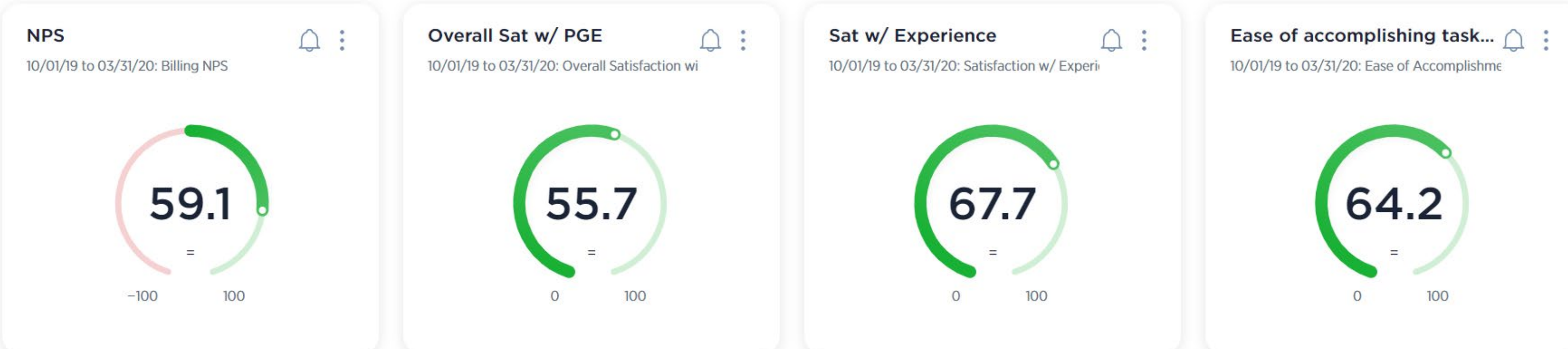
Exhibit 2501 is voluminous in size and provided only in electronic format

Exhibit 2502 is voluminous in size and provided only in electronic format

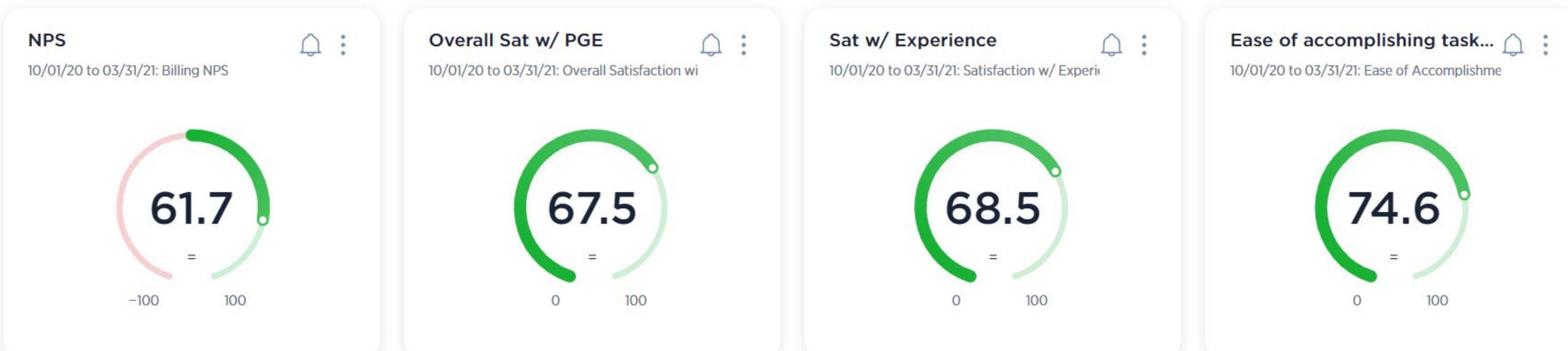
Exhibit 2503C is Confidential
and provided only in
electronic format

Billing & Payment Customer Scores (same period to avoid seasonality)

10/1/2019 – 3/31/2020 (Before Non-Res FFBC)



10/1/2020 – 3/31/2021 (Same time period after Non-Res FFBC)



NPS = Net Promoter Score;
Sat w/PGE = Overall Satisfaction with PGE;
Sat w/Experience = Satisfaction with paying using a Card
CES = Customer Engagement Score (ease to accomplish paying with card).

Customer Comments for Card*

“I would like to be able to set up Auto Pay with Credit Card. It is a hassle to come to the website each month and pay with bill matrix. I do not like that I have to make 2 payments when the bill is over $600, bill matrix should allow the full amount to be paid in one transaction.” 10 / 12/ 2020

“You are the only utility company that does not offer a CC payment option free & inexplicably cap it at $600. Magnified more now due pandemic and ancillary problems. Would be nice to have that offered to give businesses more time to budget, while you still get paid.” 08/02/2020

“trying to make payment of $6700 and only accept $600 at a time and almost $5 per transaction that meant i would have to pay additional $55+ for the Billpay. Not sure why still one transaction and cap was put on it for a payment. My perception was pge trying to make $ for their merchants and not for their customers.” 03/19/2020

“I think it's ridiculous that you will only let me pay $600 per transaction by credit card. So I have to make more than one payment, and then you're charging me $4.95 per payment. That is absolutely a rip off.” 04/19/2019

Source: Customer Connections Surveys

* Business Definition based on judgement

Exhibit 2505C is Confidential
and provided
only in electronic format

Exhibit 2506HC is Highly
Confidential and provided
only in electronic format

Exhibit 2507C is Confidential
and provided only in
electronic format

Exhibit 2508HC is Highly Confidential and provided only in electronic format

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Faraday Repowering

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Larry Bekkedahl
Jay Tinker

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Larry Bekkedahl. I am the Senior Vice President of Advanced Energy Delivery. My qualifications appear at the end of PGE Exhibit 500.

My name is Jay Tinker. I am the Director of Rates and Regulatory Affairs at PGE. My qualifications appear at the end of this testimony.

Q. Mr. Tinker, do you adopt Mr. Jenkins's and Mr. Cristea's prior testimony in this matter as your own?

A. Yes, I adopt Mr. Jenkins's and Mr. Cristea's Opening Testimony (PGE Exhibit 700, Jenkins-Cristea) filed on July 9th, 2021 and Mr. Cristea's Reply Testimony and Exhibits (PGE Exhibits 1900-1905, Bekkedahl-Cristea), filed on December 2nd, 2021.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide PGE's recommendation regarding the process that the Commission should adopt to allow parties to review the prudence of the Faraday Repowering Project and for PGE to place this important asset into rates upon its completion. PGE also addresses certain issues raised by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Alliance of Western Energy Consumers (AWEC), and the Oregon Citizens' Utility Board (CUB) (collectively, Parties), with respect to the prudence and the ratemaking treatment of the Faraday Repowering Project.

Q. What ratemaking treatment does PGE propose?

A. PGE proposes that the Commission allow a continuation of the 2022 general rate case (GRC) as a second phase (2022 GRC - Phase II) starting in the July-August 2022 timeframe that will be focused on the Faraday Repowering Project. The 2022 GRC – Phase II in this docket will give Parties the opportunity to review the prudence of the Faraday Repowering Project within approximately three months of the project's in-service date, allow for a timely Commission decision regarding the recovery of prudently incurred costs, and provide for a matching of Faraday's costs and benefits in PGE's rates.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have three sections:

- Section II: Faraday Repowering Project Ratemaking
- Section III: Summary and Conclusion
- Section IV: Qualifications

II. Faraday Repowering Project Ratemaking

Q. Please summarize the prior testimony regarding the Faraday Repowering Project.

A. PGE's direct testimony (PGE Exhibit 700) explained that PGE is repowering the Faraday Hydro Facility on the Clackamas River to replace units 1 through 5, which are more than 100 years old, and to strengthen the powerhouse and flood protection systems. PGE explained that these upgrades will increase the reliability and efficiency of this important, non-emitting generation resource. Both Staff and AWEC raised concerns regarding the Faraday Repowering Project. In opening testimony (Staff Exhibit 1000) Staff raised questions regarding PGE's decision to repower Faraday and management of costs.[1] AWEC argued that "the completion of this project in time for the rate effective date in this proceeding is highly uncertain, particularly considering the ongoing global supply chain problems"[2] and that customers "should not be responsible for any of the excessive costs[.]"[3]

PGE responded to the issues raised by Staff and AWEC in PGE Exhibit 1900. In summary, PGE testified that the Faraday Repowering Project benefits customers by ensuring access to a reliable, non-emitting capacity resource for decades to come. Additionally, PGE detailed how all viable options were assessed prior to making the decision to repower Faraday[4] and provided thorough information regarding the contracting of the project[5] and the causes for the project delays.[6] PGE also provided an update that the project was 70 percent complete, with the expected in-service date now in the fourth quarter of 2022.

[1] Staff/1000, Enright/21, at 15-19
[2] AWEC/100, Mullins/20, at 10-12.
[3] AWEC/100, Mullins/21, at 9-10.
[4] PGE Exhibit 1900, Bekkedahl-Cristea/15-17
[5] PGE Exhibit 1900, Bekkedahl-Cristea/22-23 and 25
[6] PGE Exhibit 1900, Bekkedahl-Cristea/23-24

Q. Did Parties reach an agreement regarding the Faraday Repowering Project in the third stipulation?

A. Yes, given the delay in the project in-service date, Parties agreed to remove Faraday Repowering Project capital costs of approximately $119.4 million from the revenue requirement for the May 9, 2022 price effective date. The adjustment resulted in a reduction of approximately $17.2 million to the 2022 test year revenue requirement. However, PGE and Parties agreed that they are free to present arguments in this rate case regarding the most appropriate cost recovery method for the Faraday Repowering Project prudently incurred costs.

Q. Did PGE discuss in reply testimony possible alternative cost recovery options for the Faraday Project prudently incurred capital investments?

A. Yes. PGE listed in Exhibit 1900 for the Commission's consideration potential options for PGE to request recovery of prudently incurred costs for the Faraday Repowering Project. From the potential options listed, PGE proposed that the Commission allow a tariff rider that would enable PGE to recover the Faraday Repowering Project prudently incurred costs "shortly after a PGE officer has provided an attestation that the project has been placed in service."[7]

Q. What is Parties' position on the ratemaking options proposed by PGE?

A. AWEC, CUB, and Staff oppose any form of special ratemaking treatment for allowing recovery of Faraday Repowering Project prudently incurred costs outside of a GRC.

Q. What is AWEC's position?

A. AWEC opposes any special ratemaking treatment associated with the recovery of Faraday Repowering Project costs on the basis that there continues to be significant uncertainties

[7] PGE Exhibit 1900, Bekkedahl-Cristea/28, lines 13-15

regarding project in-service date and costs.[8] AWEC argues that the Faraday Repowering Project should be considered in "PGE's next GRC, where the final project, including the Company's decision to construct the project, can be fully evaluated for prudence"[9]

A. What is your response to AWEC's position?

Q. PGE's proposal for a Phase II of this GRC allows for a prudence review shortly before Faraday will go into service. This addresses AWEC's concern that the prudence review should occur when Faraday's final costs and in-service date are more certain.

Q. Please summarize CUB's position.

A. CUB argues that "Faraday's revenue requirement impact should be measured based on a 2023 test year" and thus the "Commission should reject PGE's request for a tariff rider."[10] CUB's recommendation is based on the argument that the Faraday Repowering Project expected in-service date is too late in 2022 and the project will "hardly operate within the test year, which is the basis for our [CUB's] analysis of costs and revenues in this case."[11]

Q. How do you respond to CUB's recommendation?

A. PGE disagrees that prudence of the Faraday Repowering Project and cost recovery should not be addressed in the context of the 2022 GRC simply because the project is expected to come online in the fourth quarter of 2022. The project's expected in-service date is during the 2022 test year and within seven months of the 2022 GRC rate effective date. In addition, the benefits of Faraday's continuing operation as a hydro facility are reflected in net variable power costs (NVPC) for 2022, as discussed below. In accordance with the general principle of matching incurred costs with the benefits of a certain asset, it is appropriate for the Commission to allow

[8] AWEC/300, Mullins/18, lines 1-11
[9] AWEC/300, Mullins/18, lines 17-18.
[10] CUB/400, Jenks-Gehrke/27, lines 8-10
[11] CUB/400, Jenks-Gehrke/23, lines 17-18.

recovery of Faraday prudently incurred costs upon the project in-service date, following a prudence determination. Furthermore, all 2022 test year forecast costs other than capital costs are measured as of the end of the test year.

Q. Please summarize Staff's arguments.

A. Staff opposes the alternative ratemaking treatments that PGE proposed in Exhibit 1900 arguing that "there are substantive prudence issues that need to be investigated"[12] and thus "Staff anticipates that the prudence review [of the project] may be complex and is uncertain of the results."[13] Additionally, Staff argues that "the length of time that will pass between the effective date of tariffs in this docket and the in-service date of the Faraday Repowering Project is beyond what may be a reasonable period to support the tracking approach"[14] and that in prior cases where the Commission approved tariff riders, Parties had agreed on the prudence of the investment before the tariff rider was allowed.

Q. What other issues does Staff raise?

A. Aside from discussing the appropriate ratemaking for the Faraday Repowering Project, Staff also argues that PGE failed to provide an explanation for why decommissioning the Faraday hydro plant was not considered to be a viable option when the repowering project was approved.

Q. Do you agree with Staff's assertion that PGE failed to explain why decommissioning was not considered?

A. No. As described in PGE Exhibit 1900, pages 15 and 16, PGE did not consider the decommissioning of Faraday to be a beneficial option for customers given the non-emitting,

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[12] Staff/2500, Enright/15, lines 6-7
[13] Staff/2500, Enright/8 lines 2-3
[14] Staff/2500 Enright/8

firm capacity nature of the resource, and the increasing value and scarcity of hydro generating resources. Decommissioning Faraday would result in a reduction to PGE's resource portfolio when PGE is already resource capacity deficient based on the portfolio analyses performed in PGE's 2016[15] and 2019 Integrated Resource Plans.[16] Additionally, simply decommissioning the plant would only exacerbate the regional capacity shortage observed in the Pacific Northwest Power Pool in recent years. As explained in PGE Exhibit 1900, this regional capacity shortage results in increased power market price volatility and scarcity pricing events during weather driven load excursions or other market events. The Mid-C power market exhibited such behavior during the June-July 2021 heat event, with market power prices settling as high as $489/MWh.

Q. Are there similar resources in the market that could easily be added to PGE's resource portfolio to replace Faraday?

A. No. Given the renewable portfolio standards in the WECC region and the recently adopted emission reduction requirements in Oregon and Washington, hydro resources are extremely valuable. Thus, replacing the non-emitting, firm capacity hydro resource that is Faraday with a similar new resource or a capacity agreement would be extremely challenging in today's energy market environment.

Q. What energy value does the Faraday hydro plant provide to customers in the 2022 NVPC forecast?

[15] See PGE's 2016 IRP Filing in Docket No. 66, Section 5.1.1 starting at page 114: "The Company has a relatively small capacity deficit in the initial years, increasing to an 819 MW deficit in 2021".

[16] See PGE's 2019 IRP filing in Docket LC 73, Section 4.3.2 starting at page 106: "The capacity adequacy assessment shows a range of potential need in the near term (from 309 MW to 1066 MW in 2025) with growing uncertainty over time, […]. In the Reference Case, the capacity shortage increases from 190 MW in 2021 to 685 MW in 2025 and grows to 2,639 MW in 2050."

A. Faraday provides customers with an energy benefit of approximately $5.0 million in the 2022 NVPC forecast approved by the Commission in Docket UE 391. That is, if Faraday was decommissioned and did not generate, the 2022 NVPC forecast would be higher by this amount. Additionally, customers would not receive the Production Tax Credits (PTCs) associated with the incremental generation resulting from the Faraday Repowering Project. While the 2022 AUT forecast value of Faraday PTCs was only $14 thousand because the Faraday Repowering Project was modeled with an online date of December 1, 2022, the full-year modeling of both the energy and PTC values will increase significantly for PGE's 2023 forecast. PGE's proposal seeks to match in rates the 2022 and 2023 NVPC and PTC benefits with the costs incurred to produce these benefits.

Q. Staff also claims that PGE relied upon the passage of HB 2021 to justify its decision to proceed with the Faraday Repowering Project. Is this correct?

A. No. Contrary to Staff assertion, PGE did not justify a decision made in 2016 on the 2021 passage of HB 2021. PGE made the decision to proceed with the Faraday Repowering Project after carefully assessing all options available, as detailed in PGE Exhibit 1900. It should also be noted that, although the Faraday Repowering Project replaces units 1 through 5 with more efficient, higher capacity units 7 and 8, resulting in an increase to overall plant energy generation, increasing the overall plant generation and capacity was not the primary objective or scope of the project. PGE proceeded with the Faraday Repowering Project to address the safety and reliability issues described in PGE Exhibit 1900[17] and effectively provide customers with the energy benefits of a new 46 MW hydro plant that is expected to be in-service for decades to come. The alternatives of either doing nothing or decommissioning the

[17] PGE Exhibit 1900, Bekkedahl-Cristea/14

plant were not viable options for the reasons described in PGE Exhibit 1900[18] and this testimony.

With respect to the recent passage of HB 2021 and the carbon-reduction requirements under the bill, PGE does emphasize that it is now more critical than ever to retain and repower Faraday. HB 2021 requires PGE to submit plans to reduce emissions by 80% from a baseline amount by 2030, 90% by 2035, and completely eliminate emissions by 2040. Faraday, as a non-emitting, firm capacity resource, is an important component of PGE's HB 2021 compliance plan.

Q. Staff argues that "the forecasted in-service date of March 2022 provided in the Company's initial filing is questionable at the very least" and thus "PGE should not be allowed to use the fact that the Project was included in its general rate case filing as a basis for concluding a single-issue rate proceeding at some future time to determine the ratemaking treatment for the plant."[19] Do you agree?

A. No. PGE estimated the project in-service date based on the construction reports provided by the general contractor in June 2021, right before filing the 2022 GRC and after assessing the progress at the construction site. Specifically, the construction report received on June 9, 2021 reflected a January 11, 2022 in-service date. PGE used a more conservative estimated in-service date of March 30, 2022 for the 2022 GRC initial filing to account for the construction progress observed at the construction site. This estimated in-service date was based on the best information known by PGE at the time of filing. The schedule table referenced by Staff[20]

[18] See PGE Exhibit 1900, Section II.B, at pages 14 through 17.
[19] Staff/2500, Enright/12, lines 3-7
[20] Staff/2501, Enright/2

was part of the contract Amendment Number 3 that was negotiated after PGE filed the 2022 GRC in this docket.

Q. What is the current expected in-service date for the Faraday Repowering Project?

A. The Faraday Repowering Project is expected to be placed in service in the fourth quarter of 2022. The newly hired general contractor will provide a detailed construction schedule by mid-February 2022.

Q. Did PGE provide details regarding why the project experienced delays?

A. Yes. In PGE Exhibit 1900, PGE explained why the delays in the construction schedule were outside of PGE's control, primarily due to extraordinary events that occurred during 2020 and 2021, which could not have been foreseen when the construction contract was executed. More specifically, the construction schedule and costs were impacted by a combination of the 2020 wildfires, flooding events in 2020 and early 2021, the February 2021 ice storm, and by the ongoing COVID-19 pandemic which caused the construction site to shut down for safety reasons when there was a COVID-19 outbreak. Therefore, PGE should not be penalized for project delays that were caused by extraordinary and unforeseeable events that were outside of its control.

Q. Are there additional factors that further delayed the project in-service date from March 2022 to the fourth quarter of 2022?

A. Yes. Two additional factors caused the delay of Faraday's project in-service date from March 2022 to the fourth quarter of 2022. First, the project was slowed down from production delays by the original construction general contractor due to quality and safety issues. Then, concurrently with and because of the quality and safety issues, administrative, legal, and contractual efforts to **[Begin Confidential]** [redacted]

[redacted] **[End Confidential].** While construction work slowed down during this period, we expect a return to full production by mid-February 2022.

Q. How do you respond to Staff's and AWEC's arguments with regards to the ratemaking treatment of the Faraday Repowering Project?

A. PGE takes notice of the Parties' positions and recognizes that the prudence determination for the Faraday Repowering Project will involve a thorough review of costs by the Parties. PGE's proposal for a second phase of this case allows time for this, while providing PGE with an opportunity to recover prudently incurred costs of the Faraday Repowering Project once the project is placed in-service. We provide additional arguments in support and describe our proposal for appropriate ratemaking treatment below.

Q. Before discussing PGE's ratemaking treatment proposal, please address Staff's concerns regarding the lag between the 2022 GRC effective date and the project in-service date.

A. PGE disagrees that the length of time between the UE 394 rate effective date and the online date for the project does not support a Commission decision to allow recovery of Faraday Repowering Project costs within this docket. The Faraday project is expected to come online in the fourth quarter of 2022. As Staff points out, this represents a lag of approximately 199 days. This lag is comparable to the lag experienced when Carty came online (i.e., 212 days) or the Mona-to-Oquirrh transmission project referenced by Staff in Exhibit 2500.[21] PGE agrees that more process is needed to allow Parties ample time to review project prudence. To

[21] Staff/2500, Enright/9, Table 1 – Summary of Recent Tariff Riders

allow for more process in an efficient manner, we propose a second phase to this proceeding that focuses solely on the Faraday Repowering Project.

Q. Why is a 2022 GRC – Phase II appropriate in this case?

A. The Faraday Repowering Project represents a significant capital investment that is expected to be placed in service during the 2022 test year, within approximately seven months of the 2022 GRC rate effective date. Because PGE customers will start receiving the benefits of the repowered Faraday hydro plant when the project is placed in service, they should also pay for the prudently incurred costs. Additionally, customers already receive forecasted Faraday Repowering Project energy and PTC benefits modeled based on a December 1, 2022 estimated in-service date via updated Schedule 125 (Annual Power Cost Update) prices in Docket No. UE 391. It is thus appropriate under the general principle of matching costs and benefits for the Commission to allow recovery of prudently incurred project costs upon the in-service date of the Faraday Repowering Project.

Q. You mention above that approval of a 2022 GRC – Phase II to allow a prudence determination and recovery of prudently incurred costs is consistent with the matching principle. Please address the change in rate base between the April 30, 2022 rate base used for the 2022 GRC prices and an estimated in-service date of December 1, 2022 for the Faraday Repowering Project, for the purpose of this analysis.

A. Exclusive of Faraday Repowering Project costs, PGE estimates a net plant increase of approximately $100 to $120 million by December 1, 2022 relative to the rate base included in the 2022 GRC. Therefore, at the time when the Faraday Repowering Project will be placed in service, PGE customers will receive the benefits of additional estimated net plant of approximately $100 to $120 million without paying for the incurred capital costs associated with this expected added net plant. The estimated net plant increase accounts for estimated depreciation expense on the 2022 GRC rate base, estimated plant additions and retirements during this period, and estimated depreciation expense associated with plant additions. Consequently, if approved, PGE customers would pay for prudently incurred costs and receive the benefit of Faraday without PGE updating other GRC rate base items, such that the $100 to $120 million estimated net plant addition during this period will continue to experience lag before PGE will be able to recover the associated costs. Table 1 below provides the estimated net plant change between the April 30, 2022 rate base effective date for the 2022 GRC and December 1, 2022.

Table 1: Net Plant Change April 30, 2022 – December 1, 2022 ($millions)

April 30, 2022 GRC Rate Base	$6,232.43	
Forecast Additions Range: GRC Rate Base-November 2022	$344.88	$364.88
Depreciation on GRC Rate Base: May-November 2022	-$237.98	
Forecast Depreciation on Plant Additions Range: May-November 2022	-$6.74	-$4.74
Net Plant Forecast Range at December 1, 2022	$6,332.59	$6,354.59
Net Plant Change Range	**$100.16**	**$122.16**

Q. Are there other arguments in support of a 2022 GRC – Phase II focused on Faraday prudence determination and cost recovery?

A. Yes. While PGE is experiencing other cost pressures, including inflation at a 40-year high,[22] allowing a continuation of this GRC in a second phase focused on Faraday will reduce the need or pressure for PGE to file a GRC for a 2023 test year to recover the prudently incurred costs associated with the Faraday Repowering Project so closely on the heels of this GRC. Therefore, a 2022 GRC – Phase II will provide significant administrative efficiencies by

[22] According to the US Bureau of Labor Statistics, the all items Consumer Price Index "rose 7.0 percent for the 12 months ending December [2021], the largest 12-month increase since the period ending June 1982." See the article here: https://www.bls.gov/news.release/pdf/cpi.pdf

allowing all parties and the Commission to devote the resources involved in preparing and litigating a full 2023 general rate case to other important priorities.

Q. Does a 2022 GRC – Phase II comply with the third stipulation between Parties?

A. Yes. In the third stipulation, Parties agreed that PGE will remove Faraday from the GRC for the May 9, 2022, effective date. However, the third stipulation does not preclude the Commission from authorizing a second phase of this GRC for Parties to review project prudence and the Commission to allow cost recovery when the project is place in service.

Q. Does the Commission have authority to allow the continuation of this GRC in a second phase that will be focused on Faraday?

A. Yes, we understand that the Commission has authority to adopt a phased approach and extend the timeline for resolving certain issues in a GRC filing, as long as the utility agrees to extend the suspension period for that particular issue, which PGE does in this case. The Commission has exercised this authority in prior rate cases, although not in the exact format that PGE is proposing for the Faraday Repowering Project. As detailed in Staff Exhibit 2500, the Commission allowed tariff riders for several plant additions[23] that could be viewed as a second phase of the respective GRCs. The primary difference from a ratemaking perspective is that the prudence of these projects was determined "prior to the tariff rider being allowed."[24] A 2022 GRC – Phase II would allow parties time to review the prudence of the Faraday Repowering Project, while still permitting the resource to come into rates when it goes into service subject to Commission approval.

Q. What process does PGE envision for the 2022 GRC - Phase II?

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[23] Staff/2500, Enright/9, Table 1 – Summary of Recent Tariff Riders
[24] Staff/2500, Enright/9 at line 19.

A. While PGE is open to discussing the appropriate process with parties, PGE envisions that the 2022 GRC - Phase II will commence in July or August 2022 when the repowering project is nearing completion. PGE suggests that the schedule allow for three rounds of testimony, a hearing if desired, and briefing.

III. Summary and Conclusion

Q. Please summarize your position on the issues raised by Parties with respect to the Faraday Repowering Project.

A. While PGE does not agree with Parties' criticisms regarding the project prudence, we recognize that Parties require more process to fully review the project costs and prudence. Therefore, PGE is proposing that the Commission allow a continuation of the 2022 GRC in a second phase starting in the third quarter of 2022 that will be focused on reviewing the Faraday Repowering Project costs and allowing PGE to recover prudently incurred costs of the project starting with the project in-service date.

Q. Does this conclude your testimony?

A. Yes.

IV. Qualifications

Q. Mr. Tinker, please describe your qualifications.

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department at PGE since 1996.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Trojan NDT

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Ryan Van Oostrum
Stefan Cristea

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Ryan Van Oostrum. My position at PGE is Manager of Financial Reporting and Research and Asset Accounting. My qualifications appear at the end of this testimony.

My name is Stefan Cristea. My position at PGE is Senior Regulatory Analyst in the Rates and Regulatory Affairs department. My qualifications appear at the end of PGE Exhibit 700.

Q. Mr. Van Oostrum, do you adopt Mr. Bekkedahl's prior testimony in this matter as your own?

A. Yes, I adopt Mr. Bekkedahl's Reply Testimony in this matter (PGE Exhibit 1900, Bekkedahl-Cristea) filed on December 2, 2021.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address proposed adjustments provided by the Alliance of Western Energy Consumers (AWEC) and the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), (collectively, Parties) with respect to the Trojan Nuclear Decommissioning Trust (NDT).

Q. How is the remainder of your testimony organized?

A. After this introduction, we have three sections:

- Section II: Trojan Nuclear Decommissioning Trust
- Section III: Summary and Conclusion
- Section IV: Qualifications

II. Trojan Nuclear Decommissioning Trust

Q. Please provide a bit of background regarding the Trojan NDT funding.

A. The Trojan NDT provides financial assurance for PGE's decommissioning obligations for the Trojan nuclear generating unit, as required by the Nuclear Regulatory Commission. As described in detail in PGE/1900, the trust has been funded by a combination of reimbursements PGE received from the United States Department of Energy (DOE) pursuant to a settlement agreement, and by PGE customer contributions. In the past, PGE refunded DOE reimbursements to customers via Schedule 143 and collected from customers an annual accrual amount that was contributed to the trust. After PGE's 2019 general rate case, PGE began contributing the DOE reimbursements directly into the trust rather than refunding them to customers via Schedule 143, and reduced the annual accrual amount collected from customers accordingly, as agreed by Parties in Docket No. UE 335.

Q. Please summarize the opening testimonies from Parties regarding the Trojan NDT.

A. OPUC Staff testified that they "analyzed the assets included in the [Trojan Nuclear Decommissioning] trust and the Company's financial assumptions about the trust" and found "no notable outliers in the financial assumptions used by the Company."[1] Staff concluded that no adjustment is needed for the Trojan NDT.[2]

However, AWEC recommended that PGE refund to customers approximately $10.5 million that PGE received from the DOE between 2015 and 2019 as reimbursements associated with the Trojan Independent Spent Fuel Storage Installation (ISFSI).[3] Additionally, AWEC recommended that PGE refund to customers the $1.9 million Trojan

[1] Staff/500, Fjeldheim/46, lines 2-3 and 18-19.
[2] Staff/500, Fjeldheim/47.
[3] AWEC/100, Mullins/42.

annual accrual collected in 2020 on the basis that PGE did not add this amount to the Trojan NDT in 2020.[4]

Q. Did PGE respond to the recommendations provided by AWEC in opening testimony?

A. Yes. PGE responded to AWEC's arguments in PGE Exhibit 1900. PGE explained that AWEC's recommendations are not reasonable because they did not consider that:

- PGE refunded DOE reimbursements to customers until Schedule 143 prices were set to zero in January 2020;
- Customers currently receive the benefit of lower Trojan annual accruals due to the Trojan accrual modeling assumption that DOE reimbursements for allowable costs incurred in a certain year are contributed to the trust and start earning interest in the immediately following year, irrespective of when the transfers of funds to the trust actually occur; and
- PGE proposed to maintain the current annual accrual rate of $1.9 million in this rate case, despite the fact that the Trojan NDT model suggests the annual accrual amount should be increased since the Trojan NDT will be deficient starting in 2056.

A. Response to AWEC's Rebuttal Testimony

Q. Did AWEC revise their recommendation in rebuttal testimony?

A. Yes. AWEC recognized that its original recommendation was based on incorrect assumptions.[5] AWEC now recommends that "PGE refund $3,312,642 to ratepayers over a 12-month period through Schedule 143, representing the 2018 claim year reimbursements and the residual interest balance."[6]

[4] AWEC/100, Mullins/42.
[5] AWEC/300, Mullins/10.
[6] AWEC/300, Mullins/16, line 8-9

Q. What is the basis for AWEC's revised recommendation?

A. AWEC supports its recommendation with the argument that PGE incorrectly contributed the 2018 claim year DOE reimbursement received in December 2019 to the Trojan NDT and thus, PGE should refund this amount to customers. However, AWEC also provides that PGE can "either withdraw the funds from the trust or offset the amount against future customer contributions."[7] Additionally, AWEC recommends that PGE refund to customers the residual balance of the Schedule 143 Balancing Account.

Q. How did AWEC determine the amount that they recommend PGE should refund to customers?

A. The amount is the sum of:

1. $352,098, the Schedule 143 Balancing Account residual balance, and
2. $2,960,544 representing the 2018 claim year DOE reimbursement received by PGE in December 2019.

Q. What is the basis for AWEC's recommendation regarding the first component, the residual Schedule 143 balance?

A. AWEC states that $352,098 in interest remains in the Schedule 143 balancing account that should be refunded to customers.[8]

Q. Does PGE agree with this aspect of AWEC's recommendation?

A. Yes, PGE agrees to refund to customers via Schedule 143 the $352,098 residual balance. The residual balance is primarily comprised of interest accrued on amounts recorded as regulatory liability in the Schedule 143 Balancing Account. These amounts include the 2018 and 2019

[7] AWEC/300, Mullins/16, lines 11-12
[8] AWEC/300, Mullins/16.

claim years DOE reimbursements (received in December 2019 and December 2020, respectively) that PGE contributed to the trust in December 2021.

Q. What is the basis for AWEC's recommendation regarding the second component, the 2018 claim year DOE reimbursement?

A. AWEC argues that DOE reimbursements that PGE received for claim years prior to 2019 should have been refunded to customers via Schedule 143 and not contributed to the Trojan NDT. While AWEC seems to agree that "it is appropriate to contribute the DOE reimbursements directly to the Trojan NDT in connection with the reduced customer contributions that occurred in the 2019 GRC"[9] they argue that "those amounts [i.e., the 2018 claim year DOE reimbursement received in December 2019] were for a claim year that preceded the reduction to customer contributions agreed to in the 2019 GRC".[10] Consequently, AWEC argues that PGE incorrectly contributed the claim year 2018 DOE reimbursement to the Trojan NDT and therefore, PGE should refund these amounts to customers by either withdrawing the funds from the trust or offsetting this amount against future customer contributions.

Q. When did PGE contribute the 2018 claim year DOE reimbursement to the Trojan NDT?

A. As provided in PGE Exhibit 1900,[11] PGE added the 2018 and 2019 claim year DOE reimbursements (received in December 2019 and December 2020, respectively) to the Trojan NDT in December 2021. PGE contributed these amounts to the Trojan NDT to correct the error that occurred in 2019, as detailed in PGE Exhibit 1900, and not to obstruct

[9] AWEC/300, Mullins/15, lines 13-14.
[10] AWEC/300, Mullins/15, lines 16-18
[11] PGE testified that the DOE reimbursements received in 2019 and 2020 would be added to the Trojan NDT in December 2021 or the first quarter of 2022.

AWEC's proposal, as AWEC suggests.[12] Additionally, as mentioned above, although the 2018 and 2019 claim year DOE reimbursements were not added to the Trojan NDT timely, they were recorded as regulatory liability in the Schedule 143 Balancing Account at the time they were received in December 2019 and December 2020, respectively, and accrued interest at the blended treasury rate to customers' benefit. We offer more details regarding the error that occurred in 2019 in Section II.B of this testimony.

Q. Does PGE agree with this aspect of AWEC's recommendation?

A. No. We do not agree that effectively "re-mapping" the DOE reimbursement for claim year 2018 that was received in December 2019 from the Trojan NDT to customers is either appropriate or necessary.

Q. Can PGE simply withdraw the funds from the trust, as AWEC recommends?

A. No. As described in PGE Exhibit 1900, PGE can only withdraw funds from the trust to pay for qualified expenses incurred at the Trojan ISFSI or if there are extraordinary circumstances that warrant a withdrawal. AWEC's recommendation represents neither instance. Additionally, the trust is currently slightly underfunded and AWEC's recommendation will deepen even further this underfund.

Q. Why do you find AWEC's recommendation inappropriate?

A. AWEC's recommendation is inappropriate because it is based on the flawed premise that the 2018 claim year DOE reimbursement was incorrectly added to the Trojan NDT. As AWEC recognized, pursuant to UE 335, customers enjoyed reduced annual Trojan accruals starting with the year 2019.[13] The reduced customer contribution agreed to by Parties in UE 335 was primarily due to the modeling assumption that PGE would contribute future DOE

[12] AWEC/300, Mullins/10, lines 13-15.
[13] AWEC/300, Mullins/15.

reimbursements it received, including the reimbursement for the 2018 claim year, to the Trojan NDT instead of refunding those amounts to customers via Schedule 143. Therefore, it is not appropriate for customers to enjoy reduced annual contributions starting in 2019 and also be refunded the 2018 claim year DOE reimbursement received in December 2019 that contributed to the reduction.

Q. Did AWEC review the Trojan model that was used to determine the reduced customer annual contribution in UE 335?

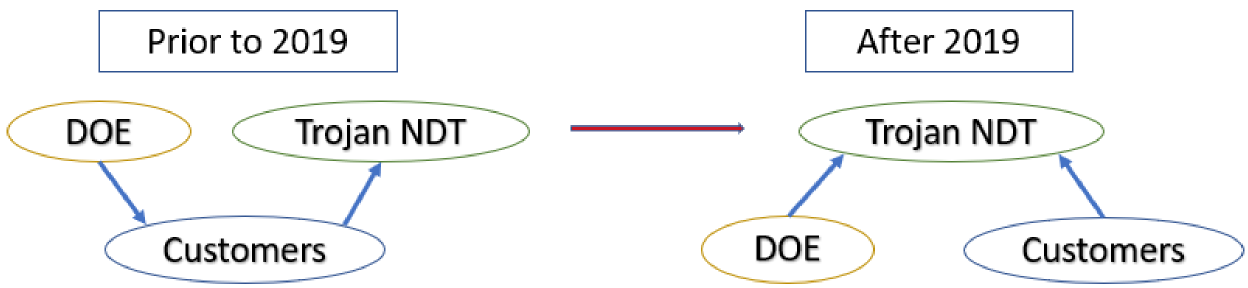
A. Yes. In UE 335, AWEC received and reviewed the Trojan model in PGE's response to AWEC Data Request No. 120, as described in AWEC's testimony in UE 335, AWEC/200, starting at page 34. The Trojan model reviewed by parties in UE 335 and provided here as Exhibit 2702 includes Table 7.5 (Annual DOE Settlement Contribution) that clearly reflects annual DOE reimbursements are contributed to the trust starting with claim year 2017.[14] Therefore, AWEC was or should have been aware that DOE reimbursements received in 2018 and beyond would be contributed to the trust. The assumption that DOE reimbursements would be added to the Trojan NDT to reduce customer annual contributions rather than being refunded to customers via Schedule 143 is not apparent in the Commission Order No. 18-464 in UE 335 because this issue regarding Trojan was settled in the Second Partial Stipulation, and therefore, PGE did not respond to AWEC's opening testimony on this issue.

Q. How did the funding of the trust changed starting with 2019, after UE 335?

A. We addressed this in detail in PGE Exhibit 1900, and Figure 1 below depicts how the Trojan NDT funding changed. Please note that, as explained in PGE Exhibit 1900, starting with year

[14] See worksheet "Return – 2018 GRC": the DOE reimbursements for allowable costs in the 2017 and 2018 claim years reflected in cells R216 and R217 are contributed to the trust as provided in cells BE217 and BE218, respectively.

2019, the customers' Trojan annual contribution was reduced to reflect that the DOE reimbursements are added directly to the Trojan NDT instead of being refunded to customers via Schedule 143.



Q. What is the result if AWEC's recommendation in this case is adopted?

A. AWEC's recommendation will result in the Trojan NDT being underfunded. While customers will temporarily benefit at the trust's expense, the Trojan annual accrual will be re-evaluated in PGE's next GRC. Specifically, customers will receive an additional $3.0 million associated with the 2018 claim year DOE reimbursement via Schedule 143 while also enjoying reduced Trojan annual contributions.[15] This imbalance between refunds to customers and customer contributions to the trust will have to be corrected with the next re-evaluation of the Trojan NDT and will likely result in an increase to the Trojan annual accrual collected from customers to make up for the $3.0 million the trust would be underfunded. AWEC's recommendation is therefore inappropriate and unnecessary because it only creates a temporary benefit to customers at the expense of the Trojan NDT, which will need to be corrected with PGE's next GRC.

[15] As noted above, the reduced customer annual contribution assumes the 2018 claim year DOE reimbursement is added to the trust.

Q. AWEC also states that the "reduced customer contributions [in Docket No. UE 335] were based on the issuance of a new Federal Energy Regulatory Commission ("FERC") license, which extended the life of the spent fuel storage facility through 2059."[16] Is this correct?

A. No. AWEC's assertion is incorrect. As stated in UE 335, PGE Exhibit 200,[17] at the time of the 2019 GRC filing, PGE was still in the process of renewing the Nuclear Regulatory Commission (NRC) license (not FERC, as AWEC provides) for Trojan for an additional 40 years. However, because the determination had not been completed yet, PGE did not use this assumption in the Trojan NDT model that determined the appropriate annual customer contribution. Exhibit 2702 provides the Trojan NDT model used in UE 335 that clearly reflects the assumption that the Trojan decommissioning would be completed in 2034 and not 2059 as AWEC claims.[18] Even AWEC, in their Exhibit 200 filed in UE 335 recognized at that time that the Trojan model was "designed to bring the balance of the trust to zero by 2034."[19] Thus, the reduction in the annual customer contribution was due primarily to the assumption that DOE reimbursements will be added to the Trojan NDT instead of being refunded to customers via Schedule 143, and not due to the Trojan NRC license extension.

B. Response to Staff's Rebuttal Testimony

Q. Did Staff revise its position regarding the Trojan NDT in its rebuttal testimony?

A. Yes. While Staff initially stated in Exhibit 500 that they reviewed the Trojan NDT and found no issue, Staff apparently reconsidered its position and now proposes that PGE "contribute

[16] AWEC/300, Mullins/13, lines 17-19
[17] UE 335, Staff Exhibit 200, page
[18] See Worksheet "Return - 2018 GRC". Tables 4 and 5 (range C184:V235) provide the assumed time range for the Trojan decommissioning with and end year of 2034. Please note that the worksheet was misnamed by PGE and it actually refers to the 2019 GRC.
[19] UE 335, AWEC/200, Mullins/34, lines 23-24

$1,000,000 to Schedule 143, replacing funds that would otherwise be provided by ratepayers".[20] Also, Staff raised concerns around the trust interest that was lost due to the delay in contributing the 2019 and 2020 DOE reimbursements to the Trojan NDT, and Staff asked that PGE clarify this issue in testimony.

Q. What is the basis for Staff's recommendation?

A. Staff did not provide any supporting information or analysis regarding why PGE shareholders should simply give $1.0 million to customers other than vaguely stating that this action would act as "as an incentive to monitor such accounts and report any issues to the Commission on a timely basis."[21] Staff did not clarify in testimony or discovery what accounts PGE would be incentivized to monitor or what issues would be subject to reporting to the Commission.[22] Additionally, Staff's recommendation is not based on an alleged violation of any statute, rule, Commission order, or policy with respect to funding the Trojan NDT, as Staff admits in the response to PGE Data Request No. 003.[23]

Q. Did Staff perform any analysis to determine the $1.0 million amount they recommend that PGE contribute to Schedule 143?

A. No, Staff's recommendation is completely unsupported. In response to PGE's Data Request No. 003, Staff responded with "N/A" (as Non-Applicable) to the request to provide work papers and analysis in support for the $1.0 million amount.

Q. Do you agree with Staff's recommendation?

A. No. Staff provided no support for its recommendation, aside from general statements about transparency. While PGE and AWEC disagree about whether the DOE reimbursements

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[20] Staff/2500, Enright/18, lines 14-16
[21] Staff/2500, Enright/18, lines 16-17
[22] PGE Exhibit 2703: OPUC Staff's response to PGE Data Request No. 003.
[23] Ibid.

should have been refunded to customers via Schedule 143 or contributed to the Trojan NDT, PGE does not currently owe customers any funds because all DOE reimbursements were either refunded via Schedule 143 prior to 2019 or contributed to the Trojan NDT following the reduction in customer annual contribution agreed to by Parties in UE 335. It is therefore unclear why and how Staff determined that a PGE contribution of $1.0 million to Schedule 143, "applied as a refund to customers […] or through a temporary reduction to the Trojan annual accrual"[24] is appropriate, and Staff does not provide any reasoning for this amount.

In addition, Staff's recommended $1.0 million refund is not commensurate with the harm Staff apparently seeks to address. While PGE previously made an error in funding the trust and delayed contributing the 2019 and 2020 DOE reimbursements to the Trojan NDT, the error has been fixed and the lost interest due to the delayed contribution was mitigated by the fact that these amounts earned interest at the blended treasury rate on behalf of customers in the regulatory liability account, and PGE has agreed to refund this amount to customers. Thus, customers were not harmed.

Q. Please explain the error that occurred.

A. In 2019, PGE refunded the 2017 claim year DOE reimbursement to customers via Schedule 143 ***and*** also contributed the same amount to the Trojan NDT. This error effectively double-counted the refund to customers because, following the 2019 test year GRC, PGE customers enjoyed Trojan annual contributions that were reduced from $3.5 million to $1.9 million due to the assumption that all DOE reimbursements starting with claim year 2017 will be contributed to the Trojan trust rather than being refunded to customers via Schedule 143.

Q. Were PGE customers harmed by the error PGE made in 2019?

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[24] Ibid.

A. No. Customers actually benefitted in 2019 because they enjoyed reduced Trojan annual contributions and were also refunded approximately $2.9 million, representing the 2017 claim year DOE reimbursement. PGE subsequently fixed the error by not contributing the $1.9 million collected from customers in 2020 to the trust and also not contributing a portion of the 2021 annual collection to make up the amount incorrectly refunded to customers in 2019.

Q. Does PGE have a process in place to avoid such errors in the future?

A. Yes. PGE has a control process in which PGE prepares a memo following resolution of a general rate case that highlights all changes or settlements that were made and describes their accounting impact. PGE will perform training to enhance the effectiveness of this process going forward. With regards to the Trojan NDT funding specifically, all relevant departments (i.e., Rates and Regulatory Affairs, Accounting, and Finance) are closely collaborating to prevent similar errors related to the Trojan NDT funding from occurring in the future. In the unlikely scenario that any issues occur in the future with regards to the Trojan NDT funding, PGE will timely communicate those issues to OPUC Staff and collaborate to resolve them.

Q. How do you respond to Staff's concern that the delayed contribution to the trust may have resulted in lost earnings?

A. The delay in adding the 2019 and 2020 DOE reimbursements to the Trojan NDT resulted in lost trust returns of approximately $163 thousand as PGE provided in the response to AWEC Data Request No. 288.[25] However, although the funds were not timely deposited into the Trojan NDT and did not earn interest in the Trojan NDT during 2020 and 2021, PGE recorded the DOE reimbursements as regulatory liability in the Schedule 143 Balancing Account, where they accrued interest at the OPUC-approved blended treasury rate for 2020 and 2021.

[25] See PGE Exhibit 2701.

Therefore, the Schedule 143 residual balance of $352,098 that PGE agreed in this testimony to return to customers incorporates a return component of $163 thousand associated with recording and holding the DOE reimbursements received in 2019 and 2020 as regulatory liability in the Schedule 143 Balancing Account. Exhibit 2703 provides the Schedule 143 Balancing Account activity between January 2019 and December 2021, reflecting the interest accrued on the Schedule 143 balance, which includes the 2019 and 2020 DOE reimbursements until they were moved to the Trojan NDT in December 2021.[26]

Q. Did the delay in adding the 2019 and 2020 DOE reimbursements to the Trojan NDT affect the amount customers are required to contribute to the trust?

A. No. The Trojan annual accrual calculation model assumes DOE reimbursements for allowable costs incurred in a certain claim year are contributed to the trust and start earning interest in the immediately following year. In actual operations, as described in PGE Exhibit 1900, page 4 at 8-14, there can be significant lag between the year when costs are incurred and when PGE receives the DOE reimbursement and funds the trust. Because of the way the model works, PGE customers are not harmed by the delays that occurred in 2019 and 2020.

[26] See the 2019 and 2020 DOE reimbursements added to the Schedule 143 Balancing Account in cells C20 and C32, respectively. The earned interest on Schedule 143 balance is reflected in range E21:E43.

III. Summary and Conclusion

Q. Please summarize your position on the recommendations provided by Parties with respect to the Trojan NDT.

A. PGE partially agrees with AWEC's recommendations. Specifically, PGE agrees to refund to customers the $352,098 residual balance of the Schedule 143 Balancing Account. However, PGE finds AWEC recommendation that PGE refund the 2018 claim year DOE reimbursement in the amount of approximately $3.0 million to customers via Schedule 143 to be inappropriate because it is based on the flawed premise that PGE incorrectly contributed this amount to the Trojan NDT. Adopting AWEC's proposal will cause the Trojan NDT to be underfunded until customer annual contributions are reevaluated within PGE's next general rate case. Therefore, the Commission should reject AWEC's recommendation on the basis that it is unnecessary, inappropriate, and will negatively impact the Trojan NDT.

With respect to the recommendation provided by Staff that PGE refund customers $1.0 million, the Commission should reject this proposal because Staff provided no support whatsoever or rationale why it should be adopted. As explained in this testimony, PGE fixed the error that occurred in 2019. Additionally, the lost interest in the Trojan NDT due to the delayed contribution to the Trojan NDT of the 2019 and 2020 DOE reimbursements was mitigated by the fact that these amounts earned interest at the blended treasury rate on behalf of customers in the regulatory liability account. Therefore, customers were not harmed.

Q. Does this conclude your testimony?

A. Yes.

IV. Qualifications

Q. Mr. Van Oostrum, please describe your qualifications.

A. I graduated from George Fox University with a Bachelor of Arts in Accountancy, majoring in Accounting and Finance. From 2008 to 2015, I was employed by PricewaterhouseCoopers LLP, working in the assurance practice with a focus on the power and utilities industry. Since joining PGE in 2016, my responsibilities as Manager of Financial Reporting and Research and Asset Accounting have included managing the Company's periodic financial reporting requirements with the Securities and Exchange Commission and Federal Energy Regulation Commission ("FERC"), as well as managing PGE's Asset Accounting department. I have 13 years of experience in accounting matters in the power and utilities industry.

List of Exhibits

Exhibit	Description
2701	PGE response to AWEC Data Request No. 288
2702C	Trojan NDT model
2703	OPUC Staff's Response to PGE Data Request No. 003
2704	Schedule 143 Balancing Account Activity 2019-2021

December 16, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 288
Dated December 9, 2021

Request:

Reference PGE/1900, Bekkedahl – Cristea/7:3-11: PGE states that customers are not harmed as a result of the delay in adding DOE reimbursements into the Trojan NDT. Does PGE agree, however, that as a result of a delay in contributing the funds, the trust returns were lower than if the funds had been contributed in a timely manner? Please explain.

Response:

PGE agrees that, if the delay in contributing these funds is viewed in isolation of other trust activities that occurred in the 2019-2021 time frame and under the assumption that the Trojan NDT returns are always positive, trust returns would be lower. For 2021 the trust returns are negative.

The lost returns associated with the delay in adding the 2019 and 2020 DOE reimbursements in the trust are approximately $160 thousand, which represents a minor impact considering that there is annual activity in the trust and no expected date for Trojan decommissioning to be finalized in the near future. However, as provided in Attachment 288-A, these lost returns are outweighed by excess returns between 2019 and 2021, which are also associated with timing mismatches. These activities are:

- Contributing the $2.8 million to the trust in 2019 while also refunding to customers in error[1] resulted in an approximately $0.3 million excess return that increased the Trojan NDT balance (see Attachment 288-A tab “Over Funded Trust CY2017 Pmt”).
- Due to COVID pandemic there was a delay in withdrawing funds from the trust to cover Trojan expenses. These funds continued to earn interest resulting in a return of approximately 60 thousand over 2020 and 2021 (see Attachment 288-A tab “Over Funded Trust-Reimbursement”).

When netting the “lost returns” against the above timing mismatches, PGE had excess returns of approximately $0.2 million (see Attachment 288-A tab “Summary Benefit to Customers”).

[1] See PGE Exhibit 1900, pages 7, line 12 through page 9, line 9.

Additionally, PGE customers are not harmed because the Trojan annual accrual calculation assumes DOE reimbursements for allowable costs incurred in a certain claim year are contributed to the trust and start earning interest in the immediately following year. In actual operations, as described in PGE Exhibit 1900, page 4 at 8-14, there can be significant lag between the year when costs are incurred and when PGE receives the DOE reimbursement and funds the trust.

Exhibit 2702 is confidential
and provided only in
electronic format

Date: January 25, 2022

TO:
JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST, 1WTC-0702
PORTLAND OR 97204
Jacquelyn.ferchland@pgn.com pge.opuc.filings@pgn.com;

FROM: Moya Enright
Senior Economist
Rates, Finance & Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 394 - PGE
Third Set Data Request filed January 18, 2023

PGE Data Request No 03:

3. Please refer to Staff Exhibit 2500 at 18: "Staff also recommends that the Commission require PGE to contribute $1,000,000 to Schedule 143, replacing funds that would otherwise be provided by ratepayers, as an incentive to monitor such accounts and report any issues to the Commission on a timely basis."

   a. Is Staff's recommendation that PGE shareholders should refund to customers $1,000,000 via Schedule 143? If no, please explain.

   b. Is Staff's recommended $1,000,000 PGE contribution to Schedule 143 intended to reduce the amount customers contribute to the Trojan NDT? If no, please explain.

   c. Is Staff's recommendation for a one-time basis or annually?

   d. Please provide all work papers and analyses (with formulas and links intact) that provide the basis for the $1,000,000 amount Staff recommends that PGE contribute to Schedule 143.

   e. To what accounts does Staff refer when it says that the recommended contribution to Schedule 143 will act "as an incentive to monitor such accounts".

   f. Please provide a detailed explanation for how and why Staff envisions that a PGE contribution to Schedule 143 will act as an incentive "to monitor such accounts and report issues…"

   g. Please provide the statute, rule, Commission order, or policy that required PGE to report the "timing issues and…error" referenced at Staff/2500, Enright/18 to the Commission.

   h. Does Staff contend that PGE's actions with respect to funding the Trojan NDT violated a statute, rule, Commission order, or policy? If so, please specify the statute, rule, Commission order, or policy and explain the violation.

<u>OPUC Response No 03</u>:

3. See subparts below.

   a. Staff's recommended $1,000,000 PGE contribution to Schedule 143 is a one-time contribution to offset PGE's customer's contribution to the Trojan NDT. This could be applied as a refund to customers via Schedule 143, or through a temporary reduction to the Trojan annual accrual.

   b. See Staff's response to section "a."

   c. See Staff's response to section "a."

   d. N/A.

   e. Staff expects PGE to conduct transactions in an accurate and timely manner, and to communicate clearly and transparently with the Commission. This expectation is not limited to any sub-set of accounts. Staff's recommended $1,000,000 PGE contribution to Schedule 143 is intended to incent PGE to be more transparent.

   f. See Staff's response to section "e."

   g. PGE asserts that it has always intended to transfer the funds to the Trojan NDT and that its failure to do so prior to the time AWEC identified this issue is simply a matter of "timing." Staff is not aware of a statute or rule that PGE violated when it did not notify the OPUC of its plan, which was to eventually place the funds received from DOE into the Trojan NDT, at the time it devised this plan. As PGE states in noted above, Staff has made a proposal designed to incent PGE to voluntarily be more transparent.

   h. In December 2019 and 2020, PGE received approximately $6.6 million in reimbursements from DOE. PGE had previously represented to the Commission that it would transfer money received from the DOE into the Trojan NDT. However, PGE did not transfer the DOE money into the Trojan NDT upon receipt. Similarly, in December 2019 PGE represented to Staff that it would transfer the residual balance of $0.4 million from Schedule 143 to Schedule 105. However, PGE did not transfer the money in the ensuing 24 months. Whether these actions are unlawful depends on PGE's intent. Accepting PGE's statements that it intends to transfer the money as true, Staff does not believe that PGE's actions have been unlawful.

SPENT FUEL ADJUSTMENT - DOE (TROJAN) -Current Reg. Liability
(AWO 3000000786)

Amortized on Sch.143 over the period of 3 years (2015-2017). Only the current portion of the liability is moved to account 2540005. The rest of the DOE payment was moved from the trust account in Feb.-2015 and is recorded on long-term liability account 2540003. Amortization is approved in UE-283 (OPUC Order No.14-422, 12.04.2014). There is no separate stipulation in the order on the Trojan amortization, however, the testimonies were approved by OPUC as part of the 2015 GRC.
As stated in the order, "PGE will maintain balancing accounts to track the difference between the Trojan Nuclear Decommissioning Trust Fund refund and the ISFSI payments and the actual

			Sch143	4310002	
		Accrual /	4070001	**Interest on**	**2540003/5**
Month		**Deferral**	**Amortization**	**Avg Balance**	**Balance**
January	2019	-	241,794.43	(9,658.80)	(2,987,841.11)
February			273,120.92	(8,886.49)	(2,723,606.68)
March			275,631.53	(8,059.05)	(2,456,034.20)
April			230,097.64	(7,296.07)	(2,233,232.63)
May			215,949.36	(6,623.72)	(2,023,906.99)
June			233,791.86	(5,943.52)	(1,796,058.65)
July			237,742.80	(5,227.23)	(1,563,543.08)
August			245,925.50	(4,489.81)	(1,322,107.39)
September			241,676.59	(3,743.96)	(1,084,174.76)
October			234,200.81	(3,014.05)	(852,988.00)
November			241,819.04	(2,281.64)	(613,450.60)
December		**(2,960,544.01)**	282,221.15	(6,085.64)	(3,297,859.10)
January	2020		147,970.04	(7,227.81)	(3,156,954.72)
February			252.50	(6,918.72)	(3,163,620.94)
March			71.46	(6,933.52)	(3,170,483.00)
April			66.06	(6,948.57)	(3,177,365.51)
May			88.19	(6,963.63)	(3,184,240.95)
June			46.15	(6,978.74)	(3,191,173.54)
July			162.38	(6,993.81)	(3,198,004.97)
August			115.56	(7,008.83)	(3,204,898.24)
September			27.18	(7,024.04)	(3,211,895.10)
October			-	(7,039.40)	(3,218,934.50)
November			-	(7,054.83)	(3,225,989.33)
December		**(3,649,446.08)**	4.15	(11,069.47)	(6,886,500.73)
January	2021		34.57	(7,116.03)	(6,893,582.19)
February			4.05	(7,123.37)	(6,900,701.51)
March			3.93	(7,130.72)	(6,907,828.30)
April				(7,138.09)	(6,914,966.39)
May				(7,145.47)	(6,922,111.86)
June				(7,152.85)	(6,929,264.71)
July				(7,160.24)	(6,936,424.95)
August				(7,167.64)	(6,943,592.59)
September				(7,175.05)	(6,950,767.64)
October				(7,182.46)	(6,957,950.10)
November		**6,609,990.09**		(3,774.72)	(351,734.73)
December				(363.46)	(352,098.19)

Total Return on Schedule 143 balance in 2020 and 2021 **(163,428.01)**

Approved Blended Treas Rate (UM-1147) - 2019	3.7400%
Approved Blended Treas Rate (UM-1147) - 2020	2.6300%
Approved Blended Treas Rate (UM-1147) - 2021	1.2400%

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Wildfire Mitigation & Vegetation Management

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Larry Bekkedahl
Jay Tinker
Brooke Brownlee

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Larry Bekkedahl. I am the Senior Vice President of Advanced Energy Delivery at PGE. My qualifications were previously provided in PGE Exhibit 500.

My name is Jay Tinker. I am the Director of Rates and Regulatory Affairs at PGE. My qualifications are included at the end of this testimony.

My name is Brooke Brownlee. I am the State Legislative Affairs Manager at PGE. My qualifications are included at the end of this testimony.

Q. Mr. Tinker and Ms. Brownlee, do you adopt Messrs. Bekkedahl's and Jenkins' prior testimony in this matter as your own?

A. Yes, we adopt Messrs. Bekkedahl's and Jenkins' Direct Testimony and Exhibits (PGE/800 – PGE/816, Bekkedahl-Jenkins) filed on July 9, 2021, and Messrs. Bekkedahl's and Jenkins' Reply Testimony and Exhibits (PGE/2000 – PGE/2009-C, Bekkedahl-Jenkins) filed on December 2, 2021.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address PGE's wildfire mitigation program and vegetation management program and respond to the testimony submitted on these topics by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff).

Q. Please summarize Staff's positions on wildfire mitigation and vegetation management in this proceeding.

A. Staff proposes a performance-based rate mechanism (PBR mechanism) applicable to PGE's wildfire mitigation costs and vegetation management costs based largely on the mechanism that the Commission adopted for PacifiCorp in its last rate case, Docket No. UE 374. That mechanism would subject PGE's prudently incurred wildfire mitigation costs, and vegetation management costs, to various penalties based on Staff's identification of probable vegetation management violations across the entirety of PGE's service territory. Staff rejects PGE's assertion that the subsequent passage of Senate Bill 762 (SB 762) materially changed the landscape for cost recovery by statutorily imposing cost recovery requirements for utility investments in wildfire mitigation. Staff also rejects PGE's assertion that the PBR mechanism's penalties are not properly tailored to achieving the mechanism's goal, particularly given the advances made by utilities in identifying a wide range of wildfire mitigation actions critical to holistic wildfire mitigation. These actions are reflected in utility wildfire protection plans, filed at the end of 2021, pursuant to SB 762.

Staff proposes to group together PGE's wildfire mitigation program and vegetation management program (referred to by Staff as "WMVM"), to withhold $3 million of "WMVM O&M expenses" from base rates, and to implement a deferral and PBR mechanism with an earnings test for PGE to recover that $3 million, plus up to an additional $3 million of incremental spending. The earnings threshold would be "based on the annual number of vegetation management violations identified by the [O]PUC's [S]afety Staff," with additional basis point reductions for violations that occur in "a Tier 2 or Tier 3 area" or are climbable tree violations.[1]

Staff found "no issues with any part of the Company's overall proposed WMVM capital or O&M expenses" as filed in PGE's direct testimony.[2] Indeed, Staff expressed no specific concerns regarding PGE's wildfire protection plan, vegetation management program, or historic level of vegetation management violations in any of its testimony.

[1] Staff/600, Dlouhy/28.
[2] Staff/600, Dlouhy/18.

Staff relies heavily on Commission Order No. 20-473 in PacifiCorp Docket No. UE 374, adopting a wildfire PBR mechanism, as justification for imposing the same mechanism on PGE. The Commission issued Order No. 20-473 on December 18, 2020, approximately six months before the July 19, 2021, effective date of SB 762, which adopted a new framework for wildfire mitigation in Oregon.

Q. How does PGE respond to Staff's position?

A. Contrary to Staff's assertions, SB 762 materially changed the landscape for wildfire mitigation cost recovery since the Commission adopted PacifiCorp's wildfire PBR mechanism in 2020. SB 762 contains explicit statutory cost recovery language that applies to utilities' investments "to develop, implement or operate" wildfire protection plans.[3] This language applies to PGE's 2022 Wildfire Mitigation Plan, filed on December 30, 2021, in Docket No. UM 2208, upon which PGE's current wildfire mitigation costs are based. While PGE will address its legal interpretation of SB 762's cost-recovery mechanism in briefing, Staff's testimony discounting SB 762's material changes to utility wildfire mitigation cost recovery is contrary to the express language of the statute which, on its face, clearly applies to PGE's wildfire mitigation costs.[4]

Moreover, even if Staff's PBR mechanism were consistent with Oregon law, which it clearly is not, that mechanism has become fundamentally outdated since it was adopted in PacifiCorp's rate case. Wildfire mitigation is the goal at issue, and Staff's PBR mechanism no longer represents an effective mechanism for reaching that goal. In fact, the mechanism will create perverse incentives that detract from PGE's successful implementation of its

[3] PGE refers to its 2022 plan as its Wildfire Mitigation Plan; this is the "wildfire protection plan" required by SB 762.

[4] PGE witnesses Macfarlane and Tang have included in their testimony a draft tariff with an automatic adjustment clause that would ensure PGE recovers its prudently incurred wildfire mitigation costs consistent with SB 762. *See* PGE/3000, Macfarlane-Tang/32.

legislatively mandated wildfire protection plan. Given the Commission's demonstrated commitment to evolving its approach to wildfire mitigation to meet the state's rapidly changing wildfire risk, PGE suggests that, before adoption, any PBR mechanism be refined to ensure it reflects the most current information, best practices, state law, and Oregon legislative policy.

PGE rejects Staff's position that its proposed PBR mechanism is appropriate for PGE in 2022. It is unpersuasive to simply point to the adoption of a similar PBR mechanism for PacifiCorp in 2020—Staff's primary argument—because of notable differences between the two companies and significant changes in the regulatory environment since Order No. 20-473 that undermine the purpose and effectiveness of that PBR mechanism.

Q. What does PGE ask of the Commission?

A. PGE asks the Commission to implement the plain language of SB 762 which requires:

> All reasonable operating costs incurred by, and prudent investments made by, a public utility to develop, implement or operate a wildfire protection plan under this section are recoverable in the rates of the public utility from all customers through a filing under ORS 757.210 to 757.220. The commission shall establish an automatic adjustment clause, as defined in ORS 757.210, or another method to allow timely recovery of the costs.[5]

First, PGE asks the Commission to approve full recovery of the amounts associated with our wildfire mitigation program and vegetation management program as requested in our direct testimony. PGE seeks $6.0 million of wildfire-related capital investments,[6] $19.4 million of wildfire-related O&M expenses ($6.6 million in our wildfire mitigation program plus $12.8 million for Advanced Wildfire Risk Reduction (AWRR), which is functionalized to our vegetation management program),[7] and $35.9 million of O&M expenses for the

[5] SB 762, Section 3(8).
[6] PGE/800, Bekkedahl-Jenkins/53.
[7] PGE/800, Bekkedahl-Jenkins/53, 55.

remainder of our vegetation management program (that is, net of AWRR).[8] In opening testimony, Staff stated that it found "no issues with any part of the Company's overall proposed WMVM capital or O&M expenses."[9]

Second, as set forth in Exhibit 3000, the surrebuttal testimony of Mr. Macfarlane and Ms. Tang, PGE asks the Commission to implement an automatic adjustment clause to allow "timely" recovery of incremental wildfire-related costs between rate cases. This complies with the requirement of SB 762 and is consistent with Commission Order No. 15-408, which interprets the exact same language of another law as mandating dollar-for-dollar recovery through an automatic adjustment clause.[10]

Third, PGE asks the Commission to approve its application for deferral of incremental costs associated with wildfire risk mitigation measures in Docket No. UM 2019, and to allow recovery of the deferred costs covered by SB 762 through the automatic adjustment clause proposed in Exhibit 3000 in this docket.[11]

PGE will demonstrate why the Commission should not approve Staff's proposed PBR mechanism, but in the event the Commission still desires to implement such a mechanism, PGE recommends a modified proposal updated to ensure it represents current best practices, as well as facts and circumstances relevant to PGE's wildfire mitigation program.

Q. How is your remaining testimony organized?

A. We address PGE's primary positions in the following sections:

- Section II – Current Regulatory Environment for Wildfire Mitigation

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[8] PGE/800, Bekkedahl-Jenkins/55.
[9] Staff/600, Dlouhy/18.
[10] Commission Order No. 15-408 at 7.
[11] *See* PGE/3000, Macfarlane-Tang/32 (requesting approval of new tariff for wildfire mitigation costs that includes an automatic adjustment clause).

- Section III – Staff's Proposed PBR Mechanism Is Outdated
- Section IV – Intended Goals
- Section V – PGE's Recommendation
- Section VI – Summary and Conclusion
- Section VII – Qualifications

II. Current Regulatory Environment for Wildfire Mitigation

Q. Please discuss recent changes in the law with respect to wildfire mitigation in Oregon.

A. On July 19, 2021, Governor Brown signed into law SB 762, a statewide framework for addressing the increasing risk of wildfires in Oregon. One component of the law requires utilities to develop and operate in compliance with a risk-based wildfire protection plan that is filed with the Commission;[12] within 180 days of the filing, the Commission must approve or approve with conditions the plan.[13] The plan must be based on reasonable and prudent practices identified through Commission workshops or codified in Commission rule, and must be designed in a manner that "seeks to protect public safety, reduce risk to utility customers and promote electric system resilience to wildfire damage."[14] The law also requires that "[a]ll reasonable operating costs incurred by, and prudent investments made by" a utility are recoverable in rates. Further, the law requires the Commission to "establish an automatic adjustment clause, as defined in ORS 757.210, or another method to allow timely recovery of the costs."[15]

Q. What actions has PGE taken to comply with the law?

A. PGE has participated in both wildfire mitigation rulemaking dockets, AR 638 and AR 648. PGE filed its 2022 Wildfire Mitigation Plan[16] with the Commission on December 30, 2021, in compliance with SB 762 and interim permanent rules adopted in Docket No. AR 648. PGE's Wildfire Mitigation Plan is the strategic document that now guides its wildfire mitigation program and spending.

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[12] SB 762, Section 3(1)
[13] SB 762, Section 3(5)
[14] SB 762, Section 3(1).
[15] SB 762, Section 3(8).
[16] *See* Exhibit 2801.

Q. What is PGE's approach to wildfire mitigation?

A. PGE's goal is to reduce the risk that electric utility infrastructure could cause a fire while limiting the impacts of specific mitigation activities, such as Public Safety Power Shutoff (PSPS) events, on customers.[17] PGE's risk model is the foundation of the program and guides activities within all six of the wildfire mitigation program's major focus areas: operating protocols, asset management and inspections, vegetation management, community outreach and public awareness, PSPS events, and research and development.[18]

Q. What changes have occurred to PGE's wildfire mitigation planning since the start of this rate case?

A. PGE's wildfire mitigation planning has continued to develop and mature over the course of 2021 and the beginning of 2022 due to evolving best practices, data-driven analysis, passage of SB 762, and the Commission's rulemaking processes. Most notably, PGE now plans to invest substantially more in its wildfire-migration activities than proposed in our direct case. To be clear, we are *not* modifying the amounts we proposed in our direct case for inclusion in base rates. We are, however, providing the most current planning and budgeting information to demonstrate the need and practicality of an automatic adjustment clause to allow PGE to timely recover incremental costs between rate cases.

PGE's direct case was filed in July 2021 and included wildfire-related mitigation expenditures forecasted in the second quarter of 2021. PGE's direct case included $6.0 million of capital for wildfire mitigation to be placed in service by April 30, 2022.[19] For wildfire-related O&M expenses, PGE's direct case included a total of $19.4 million ($6.6

[17] Exhibit 2801 at 3
[18] Exhibit 2801 at 3.
[19] PGE/800, Bekkedahl-Jenkins/53.

million of O&M in our wildfire mitigation program plus $12.8 million of O&M funding for AWRR, which is functionalized to our vegetation management program).[20]

Since then, we have developed and submitted to the Commission our 2022 Wildfire Mitigation Plan which follows OPUC wildfire rules that provide specific guidance regarding risk modeling, wildfire-related engagement with Public Safety Partners and local communities, PSPS-related communications, education and notifications, inspection and repair, vegetation management and clearances, and inspection and patrol activities within the utility-identified High Risk Fire Zone (HRFZs).[21]

When we submitted our 2022 Wildfire Mitigation Plan on December 30, 2021, we expected to spend $22.0 million on wildfire-related O&M (including AWRR), and $10.0 million on wildfire-related capital.[22] Since then, we have continued to refine and enhance our wildfire mitigation planning and budgeting and now expect to spend $28.0 million on wildfire-related O&M (including AWRR) in 2022. Our planned wildfire-related capital investment remains $10.0 million.

In summary, our planned investments in wildfire-related mitigation have increased 44% for O&M and 67% for capital since we filed our direct case. This is due to a combination of the actions we have taken to comply with SB 762 and associated rulemakings that occurred after PGE filed its direct case, as well as the rapidly evolving nature of wildfire-related planning and research.

Q. Given updated wildfire mitigation planning and budget forecasts, has PGE submitted a revision to its revenue requirement request made in this proceeding?

[20] PGE/800, Bekkedahl-Jenkins/53-55.
[21] Exhibit 2801 at 3.
[22] Exhibit 2801 at 40.

A. No. PGE has not revised its revenue requirement request made in this proceeding. PGE will seek to defer the incremental costs not included on our direct case in its pending application for deferral of wildfire mitigation costs in Docket No. UM 2019. These costs would be recoverable through the new wildfire automatic adjustment clause supported by the testimony of Mr. Macfarlane and Ms. Tang.

Q. What does SB 762 require?

A. SB 762 mandates that "all" reasonable operating costs and prudent investments related to wildfire protection plans must be recoverable in rates in a "timely" manner. The language in SB 762 is clear. An automatic adjustment clause should be established to allow for the timely recovery of all prudently incurred wildfire mitigation costs. This is what PGE proposes as the appropriate treatment for these costs moving forward.

Q. Are the wildfire mitigation costs proposed by PGE in this docket properly characterized as operating costs incurred by or investments made by PGE "to develop, implement or operate a wildfire protection plan."

A. Yes.

Q. Is there Commission precedent for implementing this type of cost recovery method?

A. Yes. As we noted, we understand that the Commission has interpreted nearly identical language in the Renewable Portfolio Standard (RPS) statute to require dollar-for-dollar cost recovery for certain investments in renewable resources and implementation of an automatic adjustment clause.[23] This issue will be addressed in more detail in PGE's briefing.

[23] *See In re Portland General Elec. Co. and PacifiCorp, dba Pacific Power Request for a Generic Power Cost Adjustment Mechanism,* Docket No. UM 1662, Order No. 15-408 at 7 (Dec. 18, 2015).

Q. In reply testimony, PGE recommended implementation of an automatic adjustment clause in lieu of Staff's proposed PBR mechanism in order to comply with the SB 762 directive.[24] How did Staff respond?

A. Staff rejected our proposal and provided three justifications. First, Staff asserted that PGE "has the opportunity to fully recover its prudently incurred costs for wildfire protection under the proposed PBR [mechanism]."[25] Second, Staff referenced the clause "or another method to allow the timely recovery of costs," which follows the language in SB 762 requiring application of an automatic adjustment clause.[26] Finally, Staff noted that "[n]o legal challenges" have been filed in response to approval of ADV 1285, "PacifiCorp's nearly identical WMVM PBR Mechanism" at the July 27, 2021 public meeting, which occurred after passage of SB 762.[27]

Q. Do you agree with Staff's conclusions?

A. No.

Q. Please discuss why Staff's proposed PBR mechanism fails to meet SB 762's requirement that a utility is legally authorized to recover all prudently incurred wildfire mitigation costs.

A. On its face, Staff's proposed PBR mechanism would not allow PGE to recover all prudently incurred wildfire mitigation costs. Staff admits as much, explaining that the mechanism would provide PGE merely the "*opportunity* [emphasis added] to fully recover its prudently incurred costs."[28]

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[24] PGE/2000, Bekkedahl-Jenkins/10.
[25] Staff/2400, Dlouhy/10.
[26] Staff/2400, Dlouhy/10.
[27] Staff/2400, Dlouhy/11.
[28] Staff/2400, Dlouhy/10.

PGE has demonstrated the prudence of its proposed wildfire-related expenditures in its direct case in this proceeding and Staff found "no issues with any part of the Company's overall proposed WMVM capital or O&M expenses."[29] Yet the PBR mechanism would put those very same costs at risk of nonrecovery. This is inconsistent with the clear directive of SB 762.

Q. Staff notes that the Commission adopted a nearly identical PBR mechanism for PacifiCorp and put it into rates after the passage of SB 762, yet PacifiCorp has not raised any legal challenges.[30] How do you respond?

A. PGE cannot speak to why PacifiCorp may or may not choose to raise legal issues at any specific point in time. In PGE's view, the statutory cost recovery provisions of SB 762 are clear. Another utility's pragmatic decision about when or how to challenge the validity of a cost recovery mechanism does not change the language of SB 762.

III. Staff's Proposed PBR Mechanism Is Outdated

Q. PGE has two separate programs, wildfire mitigation and vegetation management. Staff grouped these together in opening testimony, which PGE objected to in reply testimony. How did Staff respond in rebuttal testimony?

A. Staff continued to argue that wildfire mitigation and vegetation management are "inherently intertwined and should be addressed together."[31] Staff's justifications are insufficient for the reasons articulated below.

Q. Staff asserted that "in the Company's opening testimony[,] the Wildfire Mitigation Plan calls out vegetation management as a way to address preparedness and mitigation."[32] Is

[29] Staff/600, Dlouhy/18.
[30] Staff/2400, Dlouhy/11.
[31] Staff/2400, Dlouhy/4.
[32] Staff/2400, Dlouhy/4.

this a reasonable justification for grouping together wildfire mitigation and vegetation management?

A. No. Staff selected only one aspect, vegetation management, out of the extensive list of activities described in PGE's Wildfire Mitigation Plan. The section referenced by Staff described PGE's "comprehensive approach to the prevention and management of wildfires" and summarized eight primary components of the Wildfire Mitigation Plan, noting that each has its "own unique responsibilities" and that, combined, these activities "address Preparedness/Mitigation, Fire Season, Response, and Recovery." Of the eight components to the Wildfire Mitigation Plan, only one mentioned vegetation management. That component was "Wildfire Risk Mitigation Programs and Activities," which, itself, included six categories of activities:

- Risk management
- Vegetation management
- Asset management and inspections and capital investment
- Operating protocols
- Stakeholder engagement, and
- Research and development.

While it is true that vegetation management, specifically AWRR, is one component of wildfire mitigation, wildfire mitigation activities are far broader and more complex than simply AWRR.

Q. Staff's second justification for grouping together wildfire mitigation and vegetation management is because PGE's direct testimony "includes discussion of its Advanced

Wildfire Risk Reduction (AWRR) in its section on vegetation management."[33] How do you respond?

A. PGE does not dispute the fact that one element of its Wildfire Mitigation Plan, AWRR, is also one component of its broader, systemwide vegetation management program. The point is that much of PGE's vegetation management program has nothing to do with wildfire mitigation and much of PGE's Wildfire Mitigation Plan has nothing to do with vegetation management. As utility wildfire mitigation plans evolve, they have become multi-pronged strategies requiring investments across an array of mitigation efforts well beyond vegetation management. In light of this evolution, the PBR mechanism's singular focus on vegetation management as the lever for wildfire mitigation misses the mark. The conflation of vegetation management and wildfire mitigation has already become a dated and ineffective approach.

PGE employs a comprehensive and broad-based approach to wildfire mitigation based on the best available science, one piece of which is advanced vegetation management in HRFZs (i.e., AWRR).

PGE also needs to invest in routine vegetation management to maintain reliability and safety across its *entire* system, which is why our vegetation program contains five elements: 1) line-clearance tree trimming (routine maintenance); 2) PGE FITNES and capital support; 3) outage and storm response; 4) Enhanced Vegetations Management (EVM); and 5) AWRR.[34]

PGE has clearly demonstrated the separate functions, purposes, and goals of its wildfire mitigation program and vegetation management program. Simply because there is one overlapping portion (AWRR) does not justify grouping the two distinct programs together.

[33] Staff/2400, Dlouhy/4.
[34] PGE/800, Bekkedahl-Jenkins/54.

Q. Staff explains that conflating wildfire mitigation and vegetation management is appropriate because the Commission's rulemaking in Docket No. AR 638 [35]"devoted a workgroup to establishing Vegetation Management practices."[36] How do you respond?

A. At the beginning of the AR 638 rulemaking, the following six topical workgroups were formed:[37]

1. Wildfire Risk Analysis
2. Public Safety Power Shut-off (PSPS)
3. Community Engagement
4. Vegetation Management
5. System Hardening and Operations
6. Cost Analysis

Again, Staff has omitted significant context here, citing only one out of six workgroups the OPUC had established as part of the AR 638 rulemaking for risk-based wildfire protection plans and planned activities consistent with the Governor's Executive Order 20-04. The OPUC itself has acknowledged that wildfire mitigation goes far beyond vegetation management by including workgroups on wildfire risk analysis, PSPS, community engagement, system hardening and operations, and cost analysis. In addition, Staff has since combined all the workgroups into one joint work effort, demonstrating the need to be efficient, flexible, and responsive to changing conditions in this emerging area.[38]

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[35] Docket No. AR 638 was opened to address risk-based wildfire protection plans and planned activities consistent with Executive Order 20-04.
[36] Staff/2400, Dlouhy/4-5.
[37] Exhibit 2802 at 2.
[38] *See* Exhibit 2803.

Q. Staff's final justification for grouping together wildfire mitigation and vegetation management was that it "has been done in past rate cases, such as UE 374."[39] How do you respond?

A. PGE cannot speak to the Commission's rationale for adopting the PBR mechanism in Docket No. UE 374. But from a review of the Commission's order in Docket No. UE 374, it is not clear to PGE that this issue was actually raised, discussed, or litigated in Docket No. UE 374. PGE is raising it now, in the hope that the Commission will take a close look at PGE's concerns and, if the Commission insists on adopting a PBR mechanism in this case, will recognize that the mechanism should be updated.

PGE is unaware of any docket other than Docket No. UE 374 where the distinct categories of wildfire mitigation and vegetation management were grouped together as if they had no meaningful distinctions. In a data request, PGE asked Staff to "list all rate cases or other proceedings, other than UE 374, that group Wildfire Mitigation with Vegetation Management." Staff's response simply repeated the same statements made in testimony:

> As I note in Staff/2400, Staff believes that Wildfire Mitigation and Vegetation Management are inherently intertwined. I point out in my testimony that these two separate areas are addressed together in UE 374 when PacifiCorp's WMVM Cost Recovery mechanism was approved in Order No. 20-473. This was put into rates in ADV 1285. Additionally, the AR 638 rulemaking on Wildfire Protection Plans contained an entire workgroup devoted to Vegetation Management.[40]

Q. In reply testimony, PGE objected to Staff's proposed metric of vegetation management violations given the misalignment between the metric, goal, and program funding affected. In rebuttal testimony, Staff said that "there is an inherent link between vegetation management and wildfire mitigation" because "a vegetation management

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[39] Staff/2400, Dlouhy/5.
[40] *See* Exhibit 2804.

violation is a source of potential future ignition."[41] Was Staff able to substantiate this statement?

A. To the extent Staff means to say that *any* vegetation management violation is a source of potential future ignition, no. PGE submitted a data request to Staff asking for "all supporting analyses and documentation, including any ORS or OAR, that a 'vegetation management violation is a source of potential future ignition.' If no such analyses or documentation are available, please describe in detail Staff's factual support for this statement." Staff provided the following response:

> Staff notes that ORS [sic] 860-300-0002(h) [sic] requires the "[d]escription of the procedures, standards, and time frames that the Public Utility will use to carry out vegetation management in areas the Public Utility identified as heightened risk of wildfire." Further, it is common knowledge that contact between a tree and a powerline can create sparks that can turn into larger fires. While Staff does not believe that this needs further explanation, I refer you to this document put out by CalFire, this page about the city of Pasadena's tree trimming practices, and this news article where Pacific Gas & Electric Co. told a federal judge that a tree started the Dixie fire.[42]

PGE acknowledges that some vegetation management violations are sources of potential ignition. PGE's AWRR program was created specifically to focus on the subset of vegetation management activities that reduce the risk of wildfire. But to the extent Staff is suggesting that any and all vegetation management violations are sources of potential ignition, the references cited by Staff do not support such an assertion.

Q. PGE assumes Staff meant to reference OAR 860-300-0002(1)(h). What does OAR 860-300-0002 say about vegetation management violations?

A. OAR 860-300-0002 addresses the filing requirements for wildfire protection plans. The subsection referenced by Staff requires a utility to include in its wildfire plan a description of

[41] Staff/2400, Dlouhy/7.
[42] *See* Exhibit 2805.

how the utility intends to address vegetation management in areas identified as having "heightened risk of wildfire." This provision does not support a conclusion that any vegetation management violation is a source of potential ignition; in fact, it implies that effective wildfire mitigation focuses more narrowly on vegetation management in high-risk areas (i.e., HRFZs), as PGE's AWRR program does. Nor does it support a conclusion that a utility's wildfire protection plan is, in essence, a vegetation management program.

In fact, the rule makes clear that wildfire mitigation is far broader than vegetation management in high-risk areas. Below is summary of all ten components the rule requires a utility to include in a wildfire protection plan:

a) Areas that are subject to a heightened risk of wildfire
b) Means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk
c) Preventative actions and program the utility will carry out to minimize the risk of utility facilities causing wildfire
d) Outreach efforts regarding a protocol to de-energize of power lines
e) Protocol for the de-energization of power lines
f) Identification of the community outreach the utility will use before, during and after a wildfire season
g) Description of the procedures, standards and timeframes the utility will use to inspect utility infrastructure in areas the utility has identified as heightened risk of wildfire
h) Description the procedures, standards and timeframes the utility will use to carry out vegetation management in areas the utility has identified as heightened risk of wildfire

i) Identification of the development, implementation, and administrative costs for the plan, including discussion of risk-based cost and benefit analysis

j) Description of participation in national and international forums, and research and analysis the utility has undertaken to maintain expertise in leading edge technologies and operational practices.[43]

Q. When reading the entire OAR section referenced by Staff, what do you conclude?

A. The breadth of OAR 860-300-0002(1) underscores the complexity of wildfire mitigation and shows that it goes far beyond vegetation management. The section also highlights the necessity of concentrating wildfire-mitigation efforts, including advanced vegetation management, in HRFZs.

Q. Please explain how Staff's proposed PBR mechanism risks diverting and detracting effort and investment away from PGE's focus on HRFZs by treating vegetation management violations anywhere in PGE's service territory as equally impactful in mitigating wildfire risk.

A. Staff's proposed PBR mechanism assumes that any vegetation management violation in PGE's service area equally contributes to risk of wildfires. This is not true. This conflicts with wildfire mitigation best practices and the Commission's own requirements for wildfire protection plans which require utilities to identify areas that are subject to a heightened risk of wildfire[44] *and* to develop standards and procedures for vegetation management specifically for those areas of heightened wildfire risk.[45]

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[43] *See,* OAR 860-300-0002(1).
[44] *See,* OAR 860-300-0002(1)(a).
[45] *See,* OAR 860-300-0002(1)(h).

To effectuate wildfire mitigation, PGE needs to prioritize its efforts in HRFZs. Said more directly, a vegetation management violation in, say, downtown Portland which is not in a HRFZ, does not have the same material impact in reducing wildfire risk as mitigating actions, including advanced vegetation management, taken in HRFZs. Staff's proposed PBR mechanism risks diverting and detracting valuable and limited personnel time and customer investments away from actively addressing wildfire risks in HRFZs.

Q. Has PGE performed any analysis to see if using the metric of vegetation management violations is a reasonable metric to determine the effectiveness of its wildfire mitigation program?

A. Yes. Given that the point of overlap between the wildfire mitigation program and the vegetation management program is advanced vegetation management in HRFZs (i.e., the AWRR program), PGE performed a historical analysis to see how many vegetation management violations occurred in HRFZs.

PGE mapped the probable violations identified by Commission Safety Staff in the 2020 and 2021 OPUC annual reviews of PGE's vegetation management program to the ten HRFZs identified in PGE's 2022 Wildfire Mitigation Plan. PGE chose to use the ten HRFZs identified in the 2022 Wildfire Mitigation Plan as it is the best and most recent information available, even though we had identified only one HRFZ in our 2020 Wildfire Mitigation Plan and seven zones in our 2021 Wildfire Mitigation Plan.[46]

In 2020, OPUC Safety Staff identified 719 locations of probable vegetation management violations.[47] Of those, only thirty were located in the ten HRFZs. In 2021, OPUC Safety

[46] *See*, PGE/800, Bekkedahl-Jenkins/43; "HRFZs" were referred to as "PSPS zones" in the 2020 and 2021 Wildfire Mitigation Plans.
[47] Exhibit 2806 at 2.

Staff identified 533 locations of probable vegetation management violations.[48] Of those, again only thirty were located in the ten HRFZs.

This means that less than 6% of PGE's probable vegetation management violations over the last two years were located in HRFZs. As previously stated, a vegetation management violation anywhere on PGE's system does not pose an equal risk to wildfire ignition; this is why PGE concentrates its wildfire mitigation efforts, including but not limited to advanced vegetation management, in HRFZs.

Q. Given that Staff rely on the justification that a similar mechanism was approved for PacifiCorp, PGE asked in a data request for Staff to provide all analyses and documentation that compares and contrasts the similarities and differences of wildfire risks in PGE's service territory compared to PacifiCorp's service territory in Oregon or otherwise supports Staff's conclusion that a "nearly identical" mechanism is appropriate for PGE. How did Staff respond?

A. Staff did not provide any analysis comparing the differences in service areas between PacifiCorp and PGE, such as various ecoregions and associated wildfire risk or urban/rural density. Staff provided the following response:

> As outlined in Staff/600, Dlouhy/29, Staff recognizes that PacifiCorp's and PGE's respective service territories have inherently different wildfire risk. As such, Staff's proposed Performance Based Rate (PBR) mechanism relies on different, and higher, threshold levels in its performance targets. These thresholds were identified by Commission Safety Staff as attainable vegetation management violation targets based on PGE's historic levels of violation. Apart from the levels of the violations, Staff believes that the structure of the PBR mechanism should be the same to provide the same incentives to PGE that the Commission approved for PacifiCorp in Order No. 20-473.[49]

Q. Are the differences in PGE's and PacifiCorp's service area?

[48] Exhibit 2807 at 2.
[49] Staff response to PGE Data Request No. 11.

A. Yes, there are significant differences between PGE's and PacifiCorp's service area that directly impact the wildfire risk of each.

Q. Please briefly describe differences between the two service areas and how that impacts the wildfire risk of each.

A. PGE's service area is predominantly urban, encompassing the greater Portland metropolitan area and Salem. Approximately half of Oregon's population lives within PGE's service area. In contrast, PacifiCorp's service area in Oregon is located in less populated areas, including rural areas in Eastern Oregon and Southern Oregon and parts of the Oregon coast. Exhibit 2808 compares the service areas of each utility.

Located between the Coastal Range and the Cascade Range and in the Willamette Valley, PGE's service area is temperate and heavily influenced by the Pacific Ocean, minimizing fire risks with higher humidity and lower temperatures. In contrast, PacifiCorp's service area located Eastern Oregon and Southern Oregon are drier and hotter. Exhibit 2808 shows the average annual precipitation from 1991-2020.

The wetter, cooler weather of the Willamette Valley results in less wildfire risk in PGE's service area compared to the drier, hotter climates in much of PacifiCorp's service area. In addition, the urban density of and population centers within PGE's service area mean there are more fire response resources readily available. PGE has observed impacts of climate change, such as the lengthening of growing seasons and effects of drought stress in our forests. PGE incorporates this information as we plan vegetation management cycles, timing, and strategy.

Said more succinctly, based on the fire risks associated with the climate, geography, and urban density of PGE's service territory, approximately two percent of our customers are in areas that are at a scientifically higher risk for fire and safety-related outages (i.e., HRFZs).[50]

Q. Staff proposes to withhold $3 million of wildfire mitigation and vegetation management funds from base rates despite having found "no issues with any part of the Company's overall proposed WMVM capital or O&M expenses."[51] Does Staff's proposal, therefore, prevent the recovery in base rates of costs that have been deemed prudent in this general rate case?

A. Yes. PGE submitted a data request asking whether, given that the $3 million holdback is a part of PGE's budgeted amount for WMVM, and not an "incremental cost" and that it has already been reviewed and deemed prudent in this rate case, would recovery of this money be subject to the performance-based rate mechanism and earnings test. Staff confirmed that "[t]he $3 million holdback would be subject to the performance-based rate mechanism and earnings test."[52] In other words, some part of PGE's prudent wildfire costs would be put at risk of nonrecovery.

Q. How does PGE respond?

A. Staff's response is further evidence that the proposed mechanism conflicts with SB 762.

Q. One reason that Staff proposed to withhold $3 million in WMVM expenses and establish a PBR mechanism is the "lack of multiyear budgets." Staff asserted that "[m]ultiyear budgets would provide evidence that PGE has the intent to plan ahead to address

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[50] *See* https://portlandgeneral.com/about/info/service-area.
[51] Staff/600, Dlouhy/18.
[52] *See* Exhibit 2809.

wildfire risks as well as set aside or establish fund that PGE identifies as necessary to address wildfire risks."[53] Has PGE previously responded to this assertion?

A. Yes. PGE objected to this because this rate case filing is based on a 2022 test year revenue requirement.[54] PGE has used the test year revenue requirement in past rate cases and it is consistent with the future test year methodology the Commission allows utilities to employ.[55]

Q. Does this mean PGE does not plan its business beyond the GRC test year?

A. No. The electric utility business by its very nature requires long-term planning. PGE develops strategy, objectives, and spending plans for future years, regardless of whatever the test year is in a GRC. For example, PGE's last GRC (Docket No. UE 335) used a 2019 test year revenue requirement; we still budgeted, planned, and executed our work in the intervening years, prior to the filing of this rate case with a 2022 test year.

Q. The final, and frequent, reason Staff uses to justify the PBR mechanism is that it is very similar to the one approved for PacifiCorp in Docket No. UE 374. How are the facts and circumstances in that proceeding different than this one?

A. First, PacifiCorp asked for a mechanism to recover incremental wildfire mitigation capital costs between general rate cases because, at the time of its filing, Order No. 18-423 precluded deferrals of any costs related to capital investments. That has since changed. Under Order No. 20-147, the Commission now has the authority to allow deferrals of capital investments in specific cases.

Second, in Docket No. UE 374, Staff expressed concern about the "significant increase in safety violations related to PacifiCorp's vegetation management since 2013"[56] and

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[53] Staff/600, Dlouhy/25.
[54] PGE/2000, Bekkedahl-Jenkins/5.
[55] PGE/2000, Bekkedahl-Jenkins/5.
[56] UE 374. Staff/600, Moore/9.

suggested that "some sort of performance mechanism be developed to measure and incent improvement in safety violations related to vegetation management."[57] This goal was reiterated in the Commission Order No. 20-473 approving the mechanism: "We find that making approximately 10 percent of the company's [PacifiCorp] proposed level of increased spending subject to recovery through the mechanism will *provide an incentive to improve vegetation management* [emphasis added]."[58]

Third, Staff had concerns with PacifiCorp's proposed wildfire-related investments, saying that PacifiCorp had not "met its burden in demonstrating the necessity and prudence of its proposed [wildfire-related] investments."[59]

Fourth, the Commission intended PacifiCorp's PBR mechanism to be experimental in nature and to address PacifiCorp's increasing number of vegetation management violations. Commission Order No. 20-473 states that "it is important to monitor the implementation of the mechanism to allow us to review its operation and ensure that its goals are being met."[60] Staff has provided no evidence that this mechanism is proving successful for PacifiCorp.

Fifth, in reply testimony, PacifiCorp proposed to increase its vegetation management O&M budget by $8.8 million, Oregon-allocated, for vegetation management in order "to achieve compliance with Oregon safety standards."[61] In contrast, PGE has *not* proposed changes to its vegetation management budget or its wildfire mitigation budget in this proceeding. In response to PacifiCorp's mid-proceeding increase, Staff responded by saying: "rather than include all of these costs [$8.8 million of incremental vegetation management

[57] UE 374. Staff/600, Moore/12.
[58] Commission Order No. 20-473 at 121.
[59] UE 374. Staff/2700, Moore/17.
[60] Order No. 20-473, page 125.
[61] UE 374. PAC/3100, McCoy/25-26.

O&M] in base rates, Staff proposes that VM costs be part of an overall Wildfire and Vegetation Management Rate Recovery Mechanism."[62] This suggests that part of Staff's rationale behind the cost recovery mechanism was the incremental increase PacifiCorp proposed mid proceeding.

Finally, and critically, SB 762, which provides a framework for utility wildfire mitigation efforts and provides a clear path for recovery of reasonable operating costs, was not yet in effect.

IV. Intended Goals

Q. What is the goal intended by Staff's proposed PBR mechanism?

A. It is unclear to PGE what is the intended goal of the PBR mechanism, as Staff have provided conflicting and inconsistent rationale throughout the proceeding.

Q. According to Mr. Muldoon, Dr. Dlouhy's proposed PBR mechanism is "a holistic approach to ensuring the company is minimizing the chance of a fire and not simply adding capital investments while neglecting vegetation management."[63] How do you respond?

A. We disagree that Dr. Dlouhy's proposed PBR mechanism is "holistic" as it is narrowly focused on using vegetation management violations across PGE's entire system as the metric to determine the amount of prudently incurred investments in wildfire mitigation and vegetation management that PGE is able to recover. As described earlier in our testimony, comprehensive wildfire mitigation goes far beyond vegetation management.

[62] Staff/2700, Moore/5-6.
[63] Staff/2200, Muldoon/5-6.

Staff has made no assertions or presented evidence that PGE is "neglecting vegetation management." The evidence in this case demonstrates the contrary; PGE asked for a significant increase in vegetation management expenses in this case, well before Staff proposed its PBR mechanism. Moreover, Dr. Dlouhy himself says he finds "no issues with any part of the Company's overall proposed WMVM capital or O&M expenses."[64]

Q. PGE asked Staff to explain how Dr. Dlouhy's proposed PBR mechanism is a "holistic approach" to ensure the company is "minimizing the chance of a fire" when it only considers one metric (that is, vegetation management violations). How did Staff respond?

A. Staff's response did not explain how the proposed approach would minimize the chance of a fire as it only talked about its impact on vegetation management. Staff said that "[t]he reference to 'holistic' was meant to describe the fact the mechanism proposed by Mr. [sic] Dlouhy provides an incentive to be proactive in vegetation management and a deterrent to not being proactive in vegetation management."[65]

Q. According to Mr. Muldoon, Dr. Dlouhy's proposed PBR mechanism is "a bit of tough love recommended in that PGE is held accountable for process improvement."[66]

A. PGE expects to be accountable for process improvement and welcomes that accountability. We are committed to taking all steps necessary to ensure PGE is a part of Oregon's solution to wildfire issues. But Staff has not supported the need for any PBR mechanism, let alone the mechanism adopted in PacifiCorp's docket. That mechanism is no longer legally supportable

[64] Staff/600, Dlouhy/18.
[65] *See* Exhibit 2810.
[66] Staff/600, Muldoon, 6.

after the passage of SB 762 and, in any case, no longer reflects incentives that align with more recent utility wildfire mitigation plans and best practices.

Staff's response does indicate that Staff is aware that its proposed mechanism is punitive in nature, despite its claim to the contrary.[67] PGE has demonstrated through testimony its robust commitment, both financially and non-financially, to wildfire mitigation and vegetation management. Staff has not offered specific concerns with either of our programs and has found "no issues" with the funding requested in our direct testimony.

Q. Mr. Muldoon testifies: "Rather than give trophies for effort and participation, Dr. Dlouhy suggests that results matter because the consequences of failure are measured in terms of live, property, and natural resources. If [the PBR mechanism is] implemented, PGE will of necessity prioritize vegetation management as the primary driver of electric reliability failures as it is known to be."[68] How do you respond?

A. PGE is committed to taking all steps necessary to ensure PGE is a part of Oregon's solution to wildfire issues. PGE has presented data-driven, metric-driven, and carefully planned investments in both our vegetation management and wildfire mitigation programs. PGE's Wildfire Mitigation Plan and its request for significant budget increases for AWRR in this rate case are concrete evidence of that commitment.

PGE agrees that investing in vegetation management is critical to maintaining reliability of the system. However, Dr. Dlouhy has made clear that Staff's PBR mechanism is intended to address wildfire issues, not electric reliability issues, on the theory that vegetation management violations are "a source of potential future ignition that must be addressed" and that vegetation management violations are "a rational way to determine the effectiveness of

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[67] *See*, Staff/2400, Dlouhy/8-9.
[68] Staff/2200, Muldoon/6.

the Company's WMVM activities."[69] Mr. Muldoon's pivot to "electrical reliability" as the goal of the WMVM PBR mechanism is baffling.

Mr. Muldoon further confuses the true intent of the mechanism by concluding with: "If the Commissions wants dynamic improvement in PGE's performance to reduce risk of wildfires and transmission failures, the time is now."[70] This now introduces "reduction of transmission failures" as another, new purpose of the PBR mechanism which, again, is not discussed in Dr. Dlouhy's testimony or proposal. To be clear, minimizing the risk of "transmission failure" is included in our broader goal of "electrical reliability."

Q. What are PGE's intended goals?

A. PGE seeks to include in base rates the full amount of costs proposed in our direct testimony for both the wildfire mitigation program and the vegetation management program. PGE additionally seeks the ability to recover incremental wildfire-related costs via an automatic adjustment clause as mandated by SB 762. Regarding wildfire mitigation, PGE's goal is to reduce the risk that electric utility infrastructure could cause a fire, while limiting the impacts of specific mitigation activities, such as PSPS events, on customers. PGE's approach to wildfire mitigation continues to evolve in response to both the changing conditions that have focused worldwide attention on West Coast wildfires, and to the newly issued Commission wildfire rules. Regarding vegetation management, PGE's goal is to maintain a safe, reliable system in compliance with regulations.

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[69] Staff/2400, Dlouhy/7.
[70] Staff/2200, Muldoon/6-7.

V. PGE's Recommendation

Q. Given the facts and circumstances evidenced in this proceeding, what actions do you recommend the Commission take in this proceeding?

A. First, PGE asks the Commission to approve full recovery of the amounts associated with our wildfire mitigation program and vegetation management program as requested in our direct testimony. PGE seeks $6.0 million of wildfire-related capital investments, $19.4 million of wildfire-related O&M expenses ($6.6 million in our wildfire mitigation program plus $12.8 million for AWRR, which is functionalized to our vegetation management program), and $35.9 million of O&M expenses for the remainder of our vegetation management program (that is, net of AWRR). Staff has deemed these proposed expenditures prudent. Including the full amounts related to wildfire mitigation complies with the SB 762 requirement to provide recovery of "[a]ll reasonable operating costs…and prudent investments"[71] in wildfire mitigation. As proposed in Exhibit 3000, PGE further asks the Commission to implement an automatic adjustment clause to allow "timely" recovery of incremental wildfire-related costs between rate cases. This complies with the directive of SB 762 and, as PGE will discuss in briefing, is consistent with Commission precedent.[72]

Q. If, for whatever reason, the foregoing is not adopted, what modifications to Staff's proposed PBR mechanism would you recommend?

A. PGE believes that any mechanism that puts prudently incurred wildfire costs at risk of non-recovery is inconsistent with the clear directive of SB 762. PGE will argue in briefing that the cost-recovery language of SB 762 requires full recovery of the reasonable operating costs and

[71] SB 762, Section 3(8).
[72] Commission Order 15-08 at 7.

prudent investments covered by the statute, and the implementation of an automatic adjustment clause.

In the event the Commission disagrees with PGE's interpretation of SB 762 and decides to adopt a PBR mechanism in this docket, PGE would submit that it is time to update the mechanism's design to recognize best practices in wildfire mitigation by narrowing the scope of the mechanism to address vegetation management activities that are truly focused on wildfire mitigation. In PGE's case, that would be its AWRR program. PGE would make the following recommendations:

First, the PBR mechanism in this case would apply only to incremental costs above and beyond what is included in base rates (that is, the amounts proposed in our direct testimony Staff has reviewed and deemed prudent). Given that these costs submitted in PGE's direct testimony were reviewed by Staff and other parties for prudence, and no party took issue with the costs, there is no justification to hold those costs back and effectively put them at risk of non-recovery once again.

Second, the PBR mechanism should apply only to AWRR costs. The goal of the PBR mechanism, as PGE understands it, is to reduce wildfire risk by penalizing a utility for failing to invest appropriately in vegetation management activities that reduce wildfire risk. As PGE has explained, AWRR is a vegetation management program that specifically focuses on reducing the risk of wildfire associated with vegetation near utility assets. AWRR is a part of PGE's Wildfire Mitigation Plan and focuses on advanced vegetation management in HRFZs. To the extent a PBR mechanism is intended to incentivize expenditures in vegetation management related to wildfire mitigation, a focus on AWRR would be an appropriate target.

Third, the incremental AWRR costs would be subject to a prudence review as proposed by Staff.

Finally, the metric to determine the penalty would be only based on the number of confirmed vegetation management violations in the current HRFZs.

Table 1 shows the number of thresholds and associated penalty.

Table 1. Proposed AWRR Performance-Based Rate Criteria

Violations Level	Threshold of vegetation management violations in HRFZ	Penalty
Level I	> 30 violations	100 bps reduction
Level II	> 60 violations	150 bps reduction
Level III	> 100 violations	200 bps reduction
Plus additional 50 bps reduction if it is a climbable tree violation in a HRFZ that is not addressed by PGE within 30 days.		

Q. How did you develop the violations level and penalties shown in Table 1?

A. We based Table 1 on Table 4 provided in Staff's opening testimony,[73] with the modifications described above. For Level I violations, we used the average number of probable vegetation management violations, thirty, that were identified by OPUC Safety staff in 2020 and 2021 and are in the current HRFZs (per our 2022 Wildfire Mitigation Plan). We kept the Level I penalty at the same level proposed by Staff: 100 bps reduction. We proportionally adjusted the number of violations for Level II and Level III. For example, Staff proposed that the violations level for Level II be twice as many violations as the Level I threshold, so we did the same. Finally, we included Staff's proposed additional 50 bps reduction if the violation was a climbable tree, but again modified it to be specific to climbable tree violations in HRFZs to be consistent.

Q. Is there any basis for your proposed modifications?

[73] *See*, Table 4, Proposed WMVM Performance-Based Rate Criteria. Staff/600, Dlouhy/28.

A. Yes. With these modifications, the PBR mechanism would better align with OAR 860-300-0002(1)(h) which directs the wildfire protection plan to include, among other things, "Description of the procedures, standards, and time frames that the Public Utility will use to carry out vegetation management in in areas the Public Utility identified as heightened risk of wildfire."[74]

Q. With these modifications, does PGE believe the modified PBR mechanism is consistent with SB 762?

A. No.

VI. Summary and Conclusions

Q. Please summarize your position on recovery of wildfire mitigation and vegetation management costs.

A. Staff and other parties to this docket have reviewed the wildfire mitigation capital costs, O&M expenditures, and vegetation management costs proposed in PGE's direct testimony. No party has raised concerns about the prudence of those costs, which should be included in PGE's new rates.

All future wildfire mitigation costs within the scope of the activities described in SB 762, including the incremental additional wildfire mitigation costs included in PGE's surrebuttal testimony, should be subject to a new mechanism that allows for timely and full recovery of prudently incurred costs through an automatic adjustment clause. During the pendency of this proceeding, PGE's 2022 Wildfire Mitigation Plan was completed and filed in accordance with SB 762 and the Commission's directives in docket AR 648.

[74] OAR 860-300-0002(1)(h).

PGE also asks the Commission to approve our deferral application for incremental costs associated with wildfire risk mitigation measures in Docket No. UM 2019, which may be recovered though the automatic adjustment clause proposed in this docket. This will enable compliance with SB 762 by allowing PGE to timely recover all incremental costs associated with the development, implementation, and operation of a wildfire protection plan.

PGE believes Staff's proposed PBR mechanism is neither legally supportable nor appropriately designed for PGE for the reasons stated above. Nonetheless, if the Commission were to adopt a PBR mechanism for PGE, PGE would propose the following changes: (1) the PBR mechanism should apply only to incremental new costs beyond those proposed in PGE's direct case; (2) the PBR mechanism should apply only to AWRR costs; (3) the performance metric should be the number of vegetation management violations in the current HRFZ; and (4) the violation thresholds and associated penalties shown in Table 1 should apply.

VII. Qualifications

Q. Mr. Tinker, please describe your qualifications.

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department at PGE since 1996.

Q. Ms. Brownlee, please describe your qualifications.

A. I received Bachelor of Science degrees in Advertising and Marketing from Portland State University in 2005. I received a Master of Business Administration with a focus on General Management from Marylhurst University in 2010. I have worked for PGE since 2017. Prior to assuming the role of State Legislative Affairs Manager in 2018, I was the Local

Government Affairs Manager for Clackamas, Columbia, Deschutes, Jefferson, and Wasco counties.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	Description
2801	2022 Wildfire Mitigation Plan
2802	May 26, 2021, OPUC Staff Memo "AR 638 Workgroup Launch Announcement"
2803	August 19, 2021, OPUC Staff Memo "AR 638 Staff's Proposed Revised Scope"
2804	OPUC Staff Response to PGE Data Request No. 04
2805	OPUC Staff Response to PGE Data Request No. 07
2806	OPUC Report No. E20-49R, Portland General Electric (PGE)-Vegetation
2807	OPUC Report No. E21-53R, Portland General Electric (PGE)-Vegetation
2808	Comparison of PGE's Service Area and PacifiCorp's Oregon Service Area
2809	OPUC Staff Response to PGE Data Request No. 13
2810	OPUC Staff Response to PGE Data Request No. 16

Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

December 30, 2021

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

RE: UM 2208 – PGE's Wildfire Protection Plan

Dear Filing Center:

Please find attached the Portland General Electric Company (PGE) 2022 Wildfire Mitigation Plan (WMP) which is being submitted as required per Oregon Administrative Rule 860-300-0002(2).

PGE continues to evolve its approach to mitigating the risk of wildfires in response to changing conditions. For example, for 2022 we designated three new High Risk Fire Zones (bringing the total to 10) as a result of updating our risk assessment. In addition, PGE is expanding its situational awareness capabilities. For example, PGE is installing new remote automated weather stations, and deploying artificial intelligence-enhanced cameras to automatically notify PGE when they detect a fire, in real time. These efforts are in addition to the operational changes that occur during fire season, and our inspection and vegetation management activities. PGE anticipates that our wildfire mitigation plans will continue to evolve as our risk assessment and wildfire mitigation capabilities expand.

PGE appreciates Staff's efforts to establish permanent rules regarding utilities' wildfire mitigation plans. We look forward to continuing to work with Staff and parties to develop more comprehensive wildfire mitigation rules in AR 638, Phase II.

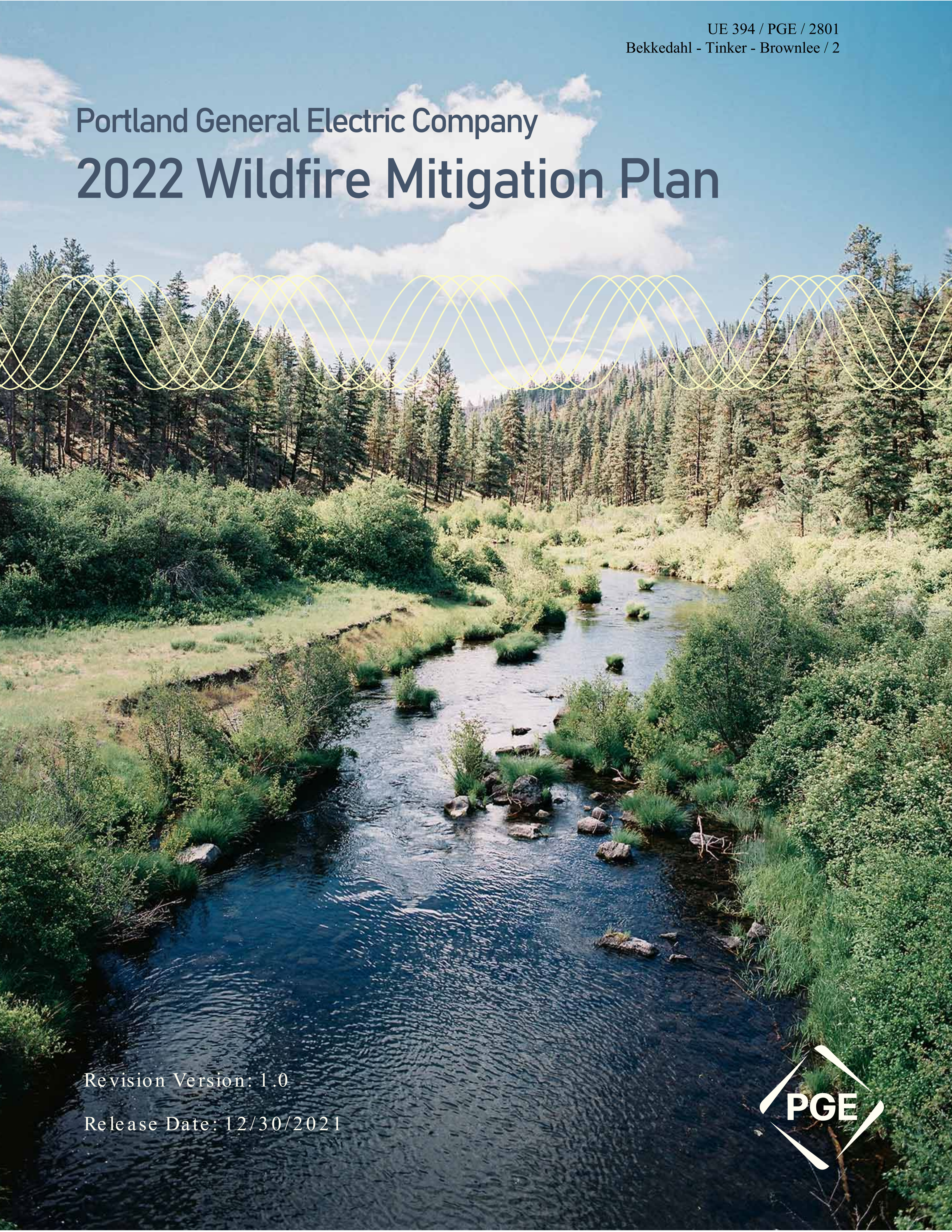
PGE looks forward to the independent evaluators review of the WMP. Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com.

Respectfully Submitted,

/s/ W. M. Messner

William M. Messner
Director Wildfire Mitigation & Resiliency

Portland General Electric Company
2022 Wildfire Mitigation Plan



Revision Version: 1.0

Release Date: 12/30/2021

This Wildfire Mitigation Plan contains statements that relate to future plans, objectives, expectations, performance and events. These forward-looking statements represent PGE's estimates and assumptions as of December 30, 2021; because PGE is continually updating its wildfire data, information included in the Plan reflects the data available at the time of publication. The Company assumes no obligation to update or revise any forward-looking statement as a result of new information, future events or other factors.

These forward-looking statements are not a guarantee of future performance and any such forward-looking statements are subject to risks and uncertainties which may be difficult to predict or are beyond PGE's control. As a result, actual results may differ materially from those projected in the forward-looking statements.

Executive Summary

Portland General Electric Company's (PGE's) Wildfire Mitigation & Resiliency (WM&R) organization plans and implements the Wildfire Mitigation Program, developing and coordinating wildfire mitigation activities across the company. The Wildfire Mitigation Plan is the strategic document that guides the Wildfire Mitigation Program.

PGE's approach to wildfire mitigation is evolving in response to both the changing conditions that have focused worldwide attention on West Coast wildfires, and to the newly-issued Public Utility Commission of Oregon (OPUC or Commission) wildfire rules. PGE's goal is to reduce the risk that electric utility infrastructure could cause a fire, while limiting the impacts of specific mitigation activities, such as Public Safety Power Shutoff (PSPS) events, on customers.

The OPUC wildfire rules provide specific guidance regarding risk modeling, wildfire-related engagement with Public Safety Partners and local communities, and PSPS-related communications and notifications. PGE is also committed to compliance with OPUC rules regarding inspection and repair, vegetation management and clearances, and inspection and patrol activities within the utility-identified High Risk Fire Zones (HRFZs).

PGE's risk model, referred to as the "Wildfire Risk Mitigation Assessment," is the foundation of the program, guiding activities within all six of the Wildfire Mitigation Program's major focus areas: operating protocols, asset management and inspections, vegetation management, community outreach and public awareness, PSPS events, and research and development.

For 2022, the updated risk assessment has led PGE to designate three new HRFZs (bringing the total to 10). PGE's HRFZ designations are for areas of PGE's service territory where vegetation, terrain, and wildland-urban interface increase the risks of fire and where PGE implements specific inspection and maintenance, vegetation management, and operational activities for wildfires, for prevention and for improved safety. In addition, PGE is expanding its situational awareness capabilities, including measures such as installing new remote automated weather stations, hiring additional full-time meteorological staff, and deploying artificial intelligence-enhanced cameras to automatically notify PGE when they detect a fire, in real time.

At PGE, wildfire-related planning and research are a year-round endeavor. PGE may update this Plan, and the Wildfire Mitigation Program throughout the year to address new findings, data and analysis. PGE will continue to work collaboratively with Public Safety Partners, local communities and other key stakeholders to prioritize the safety of people, property and public spaces. In 2022, PGE will continue to act with urgency to reduce the risk of wildfire ignitions from our assets, to respond to wildfire events and to efficiently recover from incidents.

Revisions Log

The following table details the nature, date, and primary author of major revisions to this document. All impactful revisions - revisions that make significant changes to PGE Wildfire Mitigation strategies - will be described in the Revision Description column.

Date	Version	Revision Description

Table of Contents

Section 1. Introduction

The Wildfire Mitigation Plan outlines PGE's wildfire prevention and mitigations efforts and provides guidance regarding PGE's response efforts in the event of a wildfire. The plan describes PGE's wildfire preparedness and response activities for 2022, and will be used to guide an integrated approach to achieving PGE's wildfire-related safety goals.

PGE will review its fire season operations and wildfire mitigation preparedness and response actions on an annual basis and update this plan as needed. PGE will also update the plan as required to comply with applicable regulatory requirements or changes in law. If PGE substantively updates the plan outside of the annual submission cycle, PGE will re-file the plan with the OPUC and post the most current version of the plan on PGE's website.

Section 2. Purpose and Scope

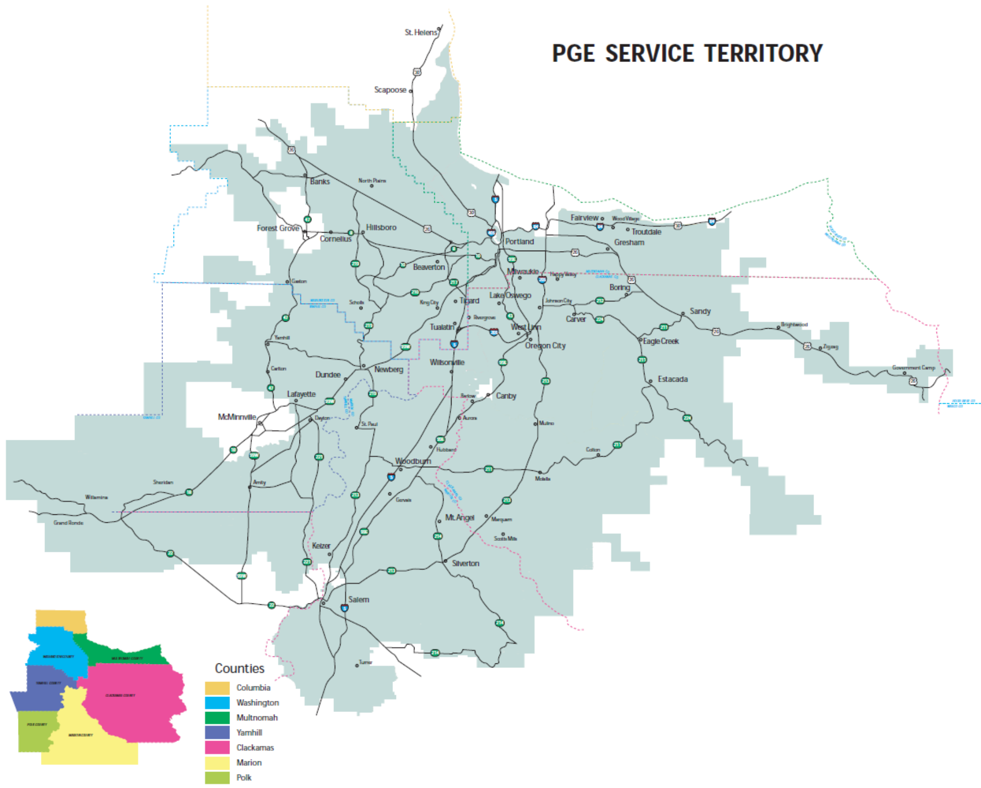
PGE's Wildfire Mitigation Plan was developed to provide strategic direction to the programs and activities that seek to mitigate the potential for PGE equipment, facilities, or activities to become wildfire ignition sources, and to ensure PGE's compliance with the OPUC's implementation of Senate Bill 762. In implementing the Wildfire Mitigation Plan, PGE will be guided by this legislation, and by the following key principles:

- Prioritize public and employee safety
- Act with urgency to reduce the risk of wildfire ignitions, to respond to wildfire events, and to recover from incidents
- Provide effective guidance to PGE's in-season wildfire operations
- Guide PGE's system hardening activities, increasing the region's resistance to wildfire impacts through a systematic, risk-based approach to identifying and prioritizing system hardening and resiliency efforts
- Communicate and collaborate with energy and Public Safety Partners (the OPUC's Emergency Support Function 12 (ESF-12), local emergency managers, and Oregon Department of Human Services), local communities and community-based organizations, counties, Federal, State and local governments, owners of critical facilities, and customers
- Maintain reliable electric service, and
- Implement Public Safety Power Shutoff (PSPS) events with efficiency, only when absolutely necessary, and with broad public awareness.

Section 3. Operating Environment

Global climate change continues to rapidly alter the Pacific Northwest climate in ways that are difficult to model and predict. This reality will drive continuous evaluation and modification of wildfire mitigation plans for the foreseeable future. In addition, the effects of climate change on California and resulting wildfires have pulled the center of gravity of West Coast wildfire mitigation to the south, increasing the competition for available fire suppression, inspection and vegetation management resources in the Northwest.

PGE's service territory is distributed over 4,000 square miles in a combination of forested, mountainous, urban and suburban environments. Much of the eastern and western portions of PGE's service area are forested, particularly in the Mt. Hood corridor along Highway 26, in the foothills of the Coast Range, and south toward Estacada. While the majority of PGE's service territory is located within the most densely populated area of the state, PGE's managed right-of-way (ROW) contains more than 2.4 million trees, with millions more off-ROW trees that present fall-in risk. PGE interconnects with multiple neighboring utilities, including the Bonneville Power Administration (BPA), PacifiCorp, West Oregon Electric Cooperative, Wasco Electric Cooperative, and Consumers Power, Inc.



Section 4. Wildfire Risk Mitigation Assessment Program Overview

PGE's primary wildfire risk mitigation objective is to reduce wildfire risk from PGE infrastructure in the communities where PGE operates while limiting the impacts of specific mitigation activities, such as PSPS events, on customers. Other risk-related objectives of the program described in this plan include:

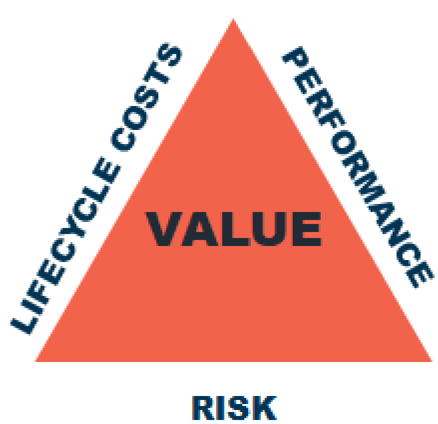
- Identify areas of heightened wildfire threat within the PGE service territory and mitigate the risk of utility-caused wildfire ignition in those areas

- Reduce the risk of wildfire ignition, prepare to respond to wildfire events, and plan for recovery from incidents
- Communicate with Public Safety Partners, operators of critical facilities, state and federal agencies, customers and communities before, during, and after wildfire season and PSPS events
- Implement a systematic, risk-based approach to identify and prioritize system hardening, vegetation management and resiliency measures
- Improve PGE's wildfire-related risk management and situational awareness capabilities, and
- Reduce the risk of future wildfire events through learning and adaptation during and after wildfire-related exercises and incidents.

One objective of PGE's Wildfire Mitigation Program is to find cost-effective ways to maximize wildfire risk reduction by applying risk assessment modeling to inform mitigation strategies. However, factors beyond PGE's control are fueling rapidly-rising costs and/or delays to project timelines, including changing West Coast weather patterns driven by climate change, competition for limited contract resources for vegetation management and inspections, and bottlenecks in the global supply chains. Investor-owned utilities, the Commission and other stakeholders must strive to achieve a reasonable balance between affordable electricity rates and meaningful wildfire risk reduction. Delivering maximum risk reduction per dollar of investment, so that PGE customers and the region receive the highest possible value for allocated resources is a key Program goal.

Climate change will continue to increase wildfire threats, requiring continual adaptation of asset management and other routine business practices. This challenging reality, combined with PGE's responsibility to maintain reliable electric service, protect public safety and resources, and conscientiously steward Oregon's natural environment, requires a careful balance between often-competing interests and system requirements. As the complexity of this analysis increases with each passing year, PGE is guided by the industry best practice of maximizing value. As defined by Institute of Asset Management (IAM) criteria encompassed in ISO 55000 standards, value is a function of lifecycle costs, performance and, ultimately, risk.

FIGURE 2: THE VALUE EQUATION



PGE factors in changing environmental conditions, unforeseen impacts to the public and the environment, quality assurance/quality control (QA/QC) on data quality, and new data sources to iterate and optimize its wildfire risk mitigation strategy. Future iterations will focus on decision support, governance, execution delivery, and internal controls. PGE follows the ISO-31000 risk framework as part of the evolution of the wildfire risk assessment process.

Section 5. Wildfire Risk Mitigation Programs & Activities

5.1 Risk Management Overview

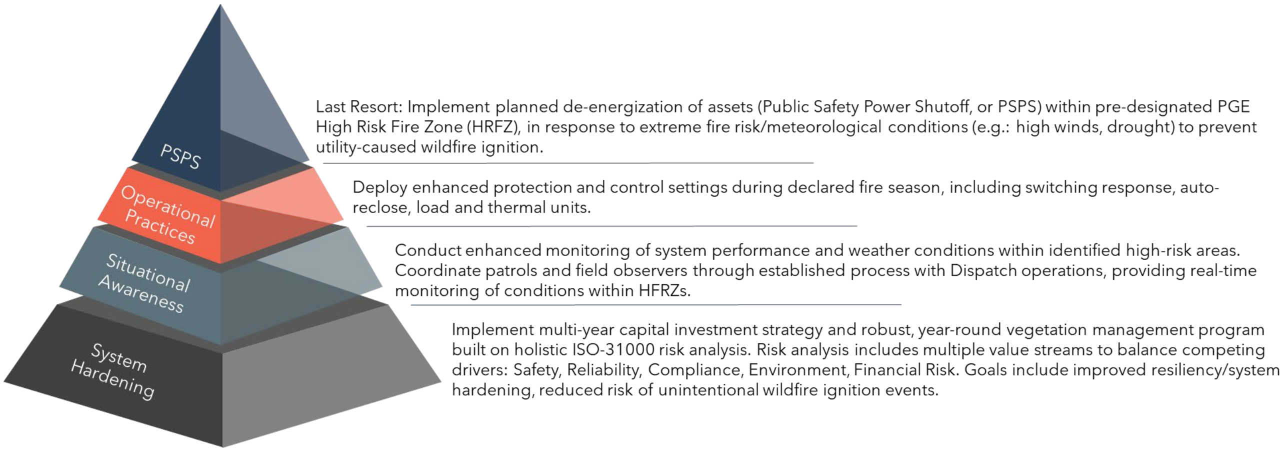
In 2019, PGE began a multi-phase wildfire risk assessment and modeling program to evaluate industry best practices, identify the highest risk fire zones within the PGE service territory, quantify the likelihood that individual PGE assets could contribute to ignition of large wildfires (>100 hectares for fires in timber; >400 hectares for fires in grass or rangeland), map their location, and apply a consequences model to determine where a potential wildfire ignition would be most significant. The annually-updated PGE statistical model enables PGE to identify the highest risk areas and prioritize wildfire mitigation actions. The model results are a key input to the development of PGE's 2022 Wildfire Mitigation Program.

Wildfire risk analysis allows PGE to assess susceptibility to the natural and human factors that contribute to utility-caused wildfire ignition and provides data-driven guidance for PGE's wildfire mitigation program. PGE's goal is to make communities, customers, employees, and facilities safer by reducing the probability of wildfires being ignited by electric utility equipment or activities, using an accurate assessment of asset-specific risk by location.

PGE's wildfire risk assessment incorporates a wide range of values, such as threats to life safety, property and financial exposure, and impacts to the environment and system reliability. This analytical approach impacts decision-making across the company, including system hardening decisions, operational and maintenance practices, and PSPS decision-making.

The following figure provides a visual representation of PGE's multi-layered approach to the complexities of wildfire risk mitigation:

FIGURE 3: PGE'S WILDFIRE RISK MITIGATION HIERARCHY



In 2022, PGE will evaluate engineering, maintenance, construction and operational strategies by leveraging the most current wildfire risk reduction model data, lessons learned from previous fire seasons, recommendations from regional Public Safety Partners, and Commission guidance and rulemaking, and by applying the following core concepts:

- Frequency of ignition events can be reduced through:
  - Vegetation management
  - Regular inspection and maintenance of poles and equipment; and
  - Engineering of reliable systems that experience fewer events that result in spark failure modes.
- When a fault event does occur, PGE can minimize the impact of the event through use of equipment and personnel to isolate and correct the problem, and
- Situational awareness and operational readiness are crucial to mitigating wildfire risk and its impacts.

5.2 Updates to 2022 Wildfire Risk Mitigation Assessment

PGE aims to improve its wildfire risk analytics and decision-making process through internal controls and feedback loops across the organization.

Following the ISO 31000 and 55000 frameworks, PGE engages external agencies in the development of new variables and inputs for consideration in the risk analysis process. In 2021, this engagement included field site visits with Oregon Department of Forestry (ODF) to look at vegetation and asset conditions that influence fire growth potential and response times to ignition events. In addition, PGE hosted virtual technical working sessions with local fire districts (Clackamas Fire District, Tualatin Valley Fire District, Multnomah Fire District) and ODF to understand fire response times, watershed boundaries and detection probabilities. These variables directly informed PGE's decision to add new High Risk Fire Zones (HRFZs) in the 2022 plan, as well as PGE's reassessment of the number and geographic boundaries of the HRFZs.

Through this post-fire season lessons learned process, PGE was able to refine its wildfire risk model outputs by introducing new variables layered on PGE's existing risk model. These new variables include:

- Line of sight
- Access/egress road density
- Detection probability, and
- Fire response time/proximity.

PGE strives to improve its understanding of wildfire risk at a granular level. The unknown impacts of climate change mean that management and analysis of wildfire risk will be a dynamic and constantly evolving task. With continuous feedback from and engagement with external stakeholders, PGE can maximize the potential of the Wildfire Mitigation Program to reduce wildfire risk.

PGE continues to investigate improvements to data sets and analytical techniques to evolve its wildfire risk assessment and integrate fire risk into PGE's overall asset and risk management frameworks. Following the 2021 wildfire season, PGE made the following changes to its baseline wildfire risk assessment:

- Began the development of a five-year wildfire risk mitigation roadmap, laying out planned mitigation activities through fiscal year 2026
- Significantly refined its HRFZ analysis, creating three new HRFZs in the western portion of the PGE service territory and eliminating portions of some 2021 HRFZs, and
- Introduced new variables to PGE's GIS-based wildfire risk mapping through virtual technical work sessions with local fire districts and the OPUC, including line-of-sight, access/egress road density, fire detection probability and estimated response time.

5.3 High Risk Fire Zones (HRFZ)

PGE has identified areas of its service territory where vegetation, terrain, and the wildland-urban interface (WUI) increase the risks associated with utility-caused wildfire ignition. For the purposes of this plan, PGE refers to these areas as High-Risk Fire Zones (HRFZs). PGE may choose to implement a proactive Public Safety Power Shutoff (PSPS) within a given HRFZ during periods of extreme wildfire threat. For 2022, PGE has identified 10 HRFZs within its service territory (see figure 4 below):

HRFZ 1: Mt. Hood Corridor/Foothills

HRFZ 2: Columbia River Gorge

HRFZ 3: Oregon City

HRFZ 4: Estacada

HRFZ 5: Scott's Mills

HRFZ 6: Portland West Hills

HRFZ 7: Tualatin Mountains

HRFZ 8: Central West Hills

HRFZ 9: North West Hills

HRFZ 10: Southern West Hills

PGE relied on the ISO-31000 wildfire risk analysis framework to identify the 2022 HRFZs, allowing PGE to incorporate new variables and refined boundary conditions to improve its understanding of:

- Wildfire risk
- Where those risks are highest within the PGE service territory
- The areas within the PGE service territory where a PSPS event could be required, and
- PGE's confidence level in its analysis.

The risk assessment factored in the likelihood that a given PGE asset could become an ignition source, as well as the likelihood that such an ignition could spread into a large, uncontrolled fire. Additional analytical factors included vegetation density, fuels dryness, the potential for extreme weather conditions, and the presence of structures and other infrastructure.

In conducting the risk analysis, PGE adjusted many variables, including temperature, humidity, fuel dryness and wind speed, and ran thousands of scenarios in a Monte Carlo simulation to identify the areas of the PGE service territory where the risks associated with a utility-caused ignition are highest. The results of this analysis provided the basis for PGE's 2022 HRFZ assessment.

The model leveraged data from PGE's Remote Sensing Pilot Project which used light detection and ranging (LiDAR) and other technologies to capture detailed topographical and vegetation measurement data for PGE's distribution system. This data allowed PGE to quantify the potential threat of wildfire ignition due to vegetation impingement and weather-caused outages. PGE calculated the probability of vegetation-caused outages using a statistical model built on historical outage data, characteristics of each distribution circuit, detailed information about the quantity, density and proximity of vegetation at a given location, as well as the expected consequence of ignition at that location.

Applying these refined risk variables, PGE identified a large geographic portion of the west side of its service territory as high-risk, resulting in the identification of three new HRFZs for 2022 (North West Hills, Central West Hills, Southern West Hills). The updated modeling also removed several highly concentrated customer areas from the 2021 PGE HRFZs, including areas in:

- Boring (South of Gresham)
- Sandy River Delta (Corbett Area)
- West Side Hills (West Portland)

These changes will reduce the total number of customers impacted by potential PSPS events during the 2022 fire season. An interactive, GIS-enabled map on the Wildfire Outages (portlandgeneral.com/wildfireoutages) and PSPS page (portlandgeneral.com/PSPS) on PGE's website (portlandgeneral.com) allows customers to enter their address to determine whether their home or business is located within an active PSPS area. PGE will provide maps of its most current HRFZs, including GIS shapefiles, to OPUC Safety staff by April 1, 2022.

FIGURE 4: PGE HIGH RISK FIRE ZONES: 2021 VS. 2022

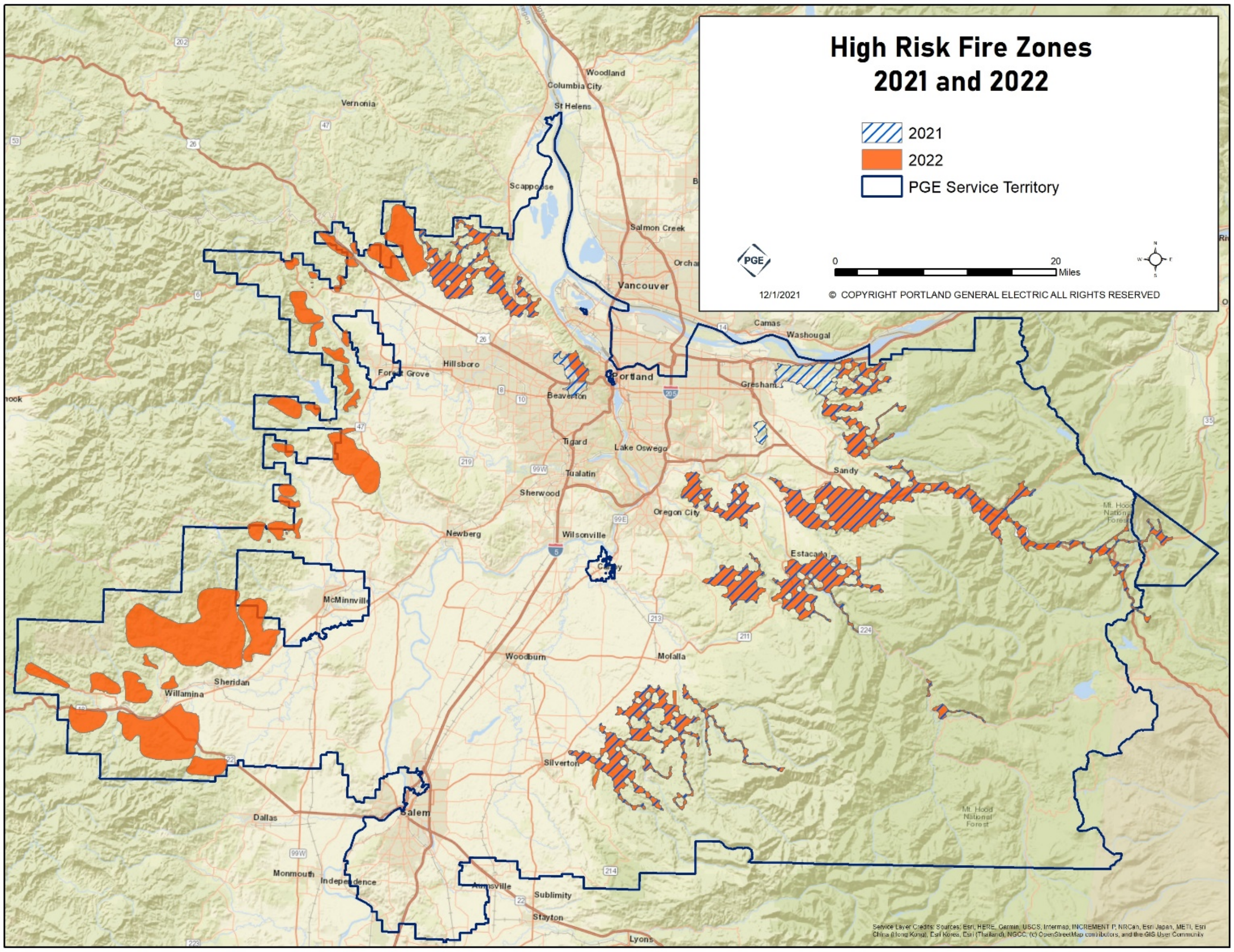
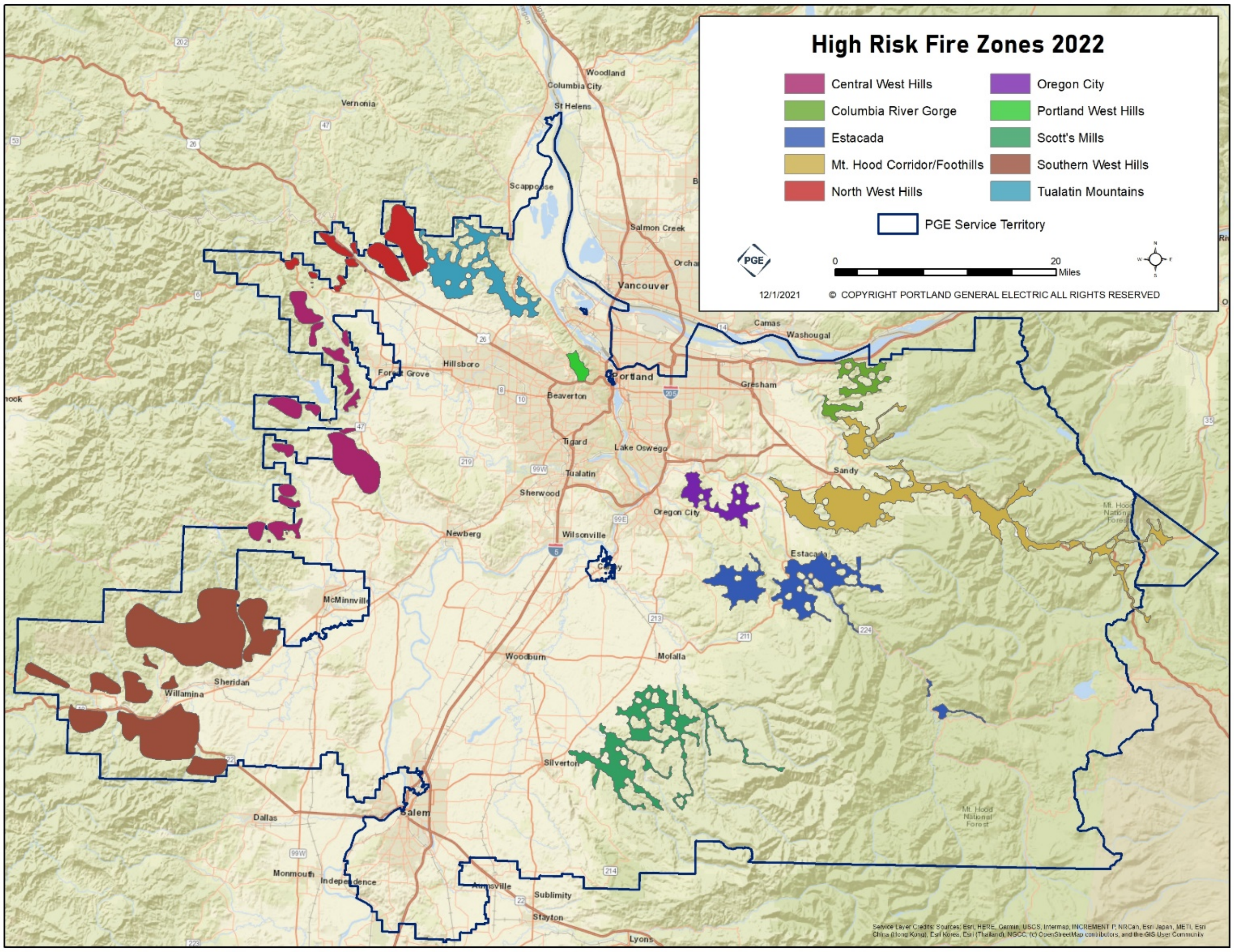

High Risk Fire Zones
2021 and 2022
2021
2022
PGE Service Territory
0
20
Miles
12/1/2021
© COPYRIGHT PORTLAND GENERAL ELECTRIC ALL RIGHTS RESERVED
Portland
Vancouver
Hillsboro
Beaverton
Gresham
Tigard
Lake Oswego
Tualatin
Sherwood
Oregon City
Wilsonville
Newberg
Forest Grove
McMinnville
Sheridan
Willamina
Sandy
Estacada
Molalla
Woodburn
Silverton
Salem
Dallas
Monmouth
Independence
Sublimity
Stayton
Lyons
Scappoose
St Helens
Columbia City
Woodland
Vernonia
Salmon Creek
Camas
Washougal

FIGURE 5: 2022 PGE HIGH RISK FIRE ZONES



5.4 Wildfire Risk Categories

PGE's wildfire risk analysis specifically considers baseline wildfire risk and risks to residential property and life. PGE uses these assessments to inform wildfire mitigation strategies that provide location-specific reliability and resiliency benefits. PGE's analysis also considers regional values such as cultural, historic, and habitat- and species-specific benefits, because these values matter to PGE, its customers and other stakeholders. PGE considers these factors to benefit the broadest possible spectrum of regional stakeholders. This holistic risk assessment approach helps PGE align specific solutions to required risk reduction areas.

This risk alignment theme is applied consistently across PGE's wildfire mitigation program, from design standards to construction practices, vegetation management, and capital investment. PGE seeks to align activities and competencies with risk, referring to and integrating mitigation outcomes from its wildfire risk analysis in assessing capital investments, maintenance activities and operational strategy.

Baseline Wildfire Risk

PGE calculates baseline equipment risk in terms of ignition probability (the annual likelihood that a given piece of equipment could cause a wildfire ignition given its type, age, condition, and location) and the consequences of ignition. These consequences evaluate how a wildfire ignited at a given location may burn, as well as the potential magnitude of the damage it may cause. In most cases, probability values vary with age and condition, increasing as equipment ages.

Seasonal Wildfire Risk, Risk to Residential Areas, and Risk to PGE Equipment

Seasonal risk and risk to residential areas are integral to PGE's wildfire risk assessment. In future iterations of PGE's wildfire risk analysis, risk to PGE equipment will also be considered, as PGE adds the capability to assess which items of equipment are most likely to be damaged if a fire occurs in a given area. PGE is developing the tools required to factor information of this granularity into its wildfire risk analysis.

Georisk

In addition to the risk categories above, PGE also models geographic wildfire risk (georisk). Georisk represents wildfire risk due to vegetation encroachment on the conductor, and/or animal contact impacting the components of the structure. Georisk is distinct from asset risk, which is defined as risk due to failed equipment. This information will be integrated into an updated PGE structures model. PGE's structures model is still in draft form and will be formally published in Q2 2022. Once the model is formally published, it will be refined through PGE's annual QA/QC review process.

This structures model allows PGE to evaluate wildfire risk at a more precise level, by identifying the specific areas of the PGE service territory where there is an increased risk of ignitions from PGE equipment due to contact from foreign objects.

5.5 Risk Assessment Data Quality & Review Frequency

PGE uses multiple data sources in the statistical models used to determine where PGE's highest wildfire risks exist. PGE's risk modeling methodology is consistent with the ISO-31000 Monitoring & Review structure, which provides internal controls to enhance confidence while still considering the dynamic nature of risk.

PGE's QA/QC process for published Asset Risk Models identifies the cadence of updates and required review tasks. Table 1 below details PGE's current data source update cadence.

Required QA/QC tasks include review and affirmation of existing or updated data, validation of subject matter expert (SME) assumptions, review of mathematical formulas and variance testing of updates to confirm that updates are reasonable.

TABLE 1 : UPDATE CADENCE FOR KEY MODELING INPUTS

Data Sources	Inputs	Cadence of Updates
Annual Probability of Asset Failure	Weibull failure curve parameters	Annual review • Affirm/update SME assumptions/updated failure data
	Health indexing	Annual review • Incorporate condition data (as available)
	Demographics from database	Periodic updates as data becomes available-GIS/Maximo
	GIS data for components on structures	Annual update to address reconfiguration/replacement
Annual Probability of Asset Caused Ignition	Probability of equipment related outage is source of ignition	Annual review • Affirm/update SME assumptions
	Probability of equipment in violation of PGE patrol/inspection guidelines	Annual review • Incorporate inspection data (as available) • Incorporate updated SME assumptions
	Equipment multipliers	Annual review • Affirm/update SME assumptions
Intervention Costs	Capital cost estimates for wildfire mitigation	Annual review • Affirm/update SME assumptions
Consequence of Wildfire	The wildfire consequence model developed by Pyrologix identifies structures in burnable locations and estimates the expected consequence of a large fire (i.e., min 400 hectare) started at each location.	Periodic updates as required

Georisk Assessment Data Sources

PGE inputs asset and georisk data sources to the Pyrologix fire physics engine to create simulated probabilistic models that assess fire risk by location, for both long-term planning and real-time decision support. PGE continues to refine variables in coordination with external agencies. This collaboration has led PGE to add new variables for consideration in its ongoing risk analysis process.

Table 2 details the data sources for the various inputs PGE uses to assess geographic wildfire risk, as well as the proposed cadence of updates to these data sources.

TABLE 2: GEORISK MODELING DATA SOURCES AND CADENCE OF UPDATES

Data Sources	Inputs	Cadence of Updates
Wildfire Modeling	Fire Propagation and Fire Behavior	• Annual review • Affirm/update SME assumptions/updated failure data • Landfire (geospatial layering program) calibration through Pyrologix proprietary adjustments
	Elevation Data	• Annual/semi-annual review • Affirm/update SME assumptions/updated failure data • National Survey Data • USGS • LIDAR
	Meteorological Data	• Annual/semi-annual review • National weather data • PGE weather stations
	Burn Probability	• Annual review • Affirm/Update SME assumptions/updated failure data • Landfire calibration through Pyrologix proprietary adjustments

5.6 Ignition Probability Values and Historic Ignition Tracking

In 2021, in response to new OPUC requirements, PGE created an ignition management tracking database and process. This allows PGE to base the system hardening investments described in the Targeted Interventions to Reduce Wildfire Risk section, below, on the risk drivers that deliver an optimized risk/spend efficiency calculation. For example, if analysis shows that georisk represents a feeder's only risk, but 99 percent of all the ignitions recorded at that site are caused by animal contact, then installing animal protection devices would likely be the appropriate risk mitigation outcome for that location.

As PGE collects risk assessment data and supplements it with lessons learned and industry best practices, it can refine its ignition probability values database to create more accurate risk projections. These risk projections, based on quantifiable drivers, allow PGE to map risk velocity (risk forecasted through time) and link it to the various strategies described in Section 5.8, Targeted Interventions to Reduce Wildfire Risk, to deliver highest-value risk mitigations.

5.7 Prioritized Opportunistic Interventions

Generally, when repairs are needed on an asset and the cost of the repair is higher than the lifecycle value of the asset, the asset should be replaced. Once crews are mobilized, there may also be reliability and economic benefits to proactive asset replacement, particularly within HRFZs. Whenever possible, PGE applies its asset risk methodology to assess the cost/benefit of proactive asset replacement during planned improvement/maintenance activities on other nearby assets. This approach helps PGE maintain reliable electric service, supporting public safety.

PGE prioritizes capital investments and maintenance activities that provide multiple benefits to the system including minimizing outage duration, asset survival and other impacts to infrastructure beyond wildfire mitigation. This multi-dimensional view allows PGE to achieve the best-value risk reduction per dollar of investment.

5.8 Targeted Interventions to Reduce Wildfire Risk

Risk Analysis for PSPS

Before and during fire season, PGE reviews regional National Weather Service forecasts, fire activity briefings, fire potential forecasts, and readings from PGE weather stations strategically located throughout the service territory daily. In 2022, PGE is deploying additional weather stations to increase situational and conditional awareness and provide visibility within the newly identify HRFZs on the west side of its service territory. PGE consulted with external meteorologists to identify locations that will provide the best overlap for wildfire risk coverage. PGE uses meteorological and outage data predictive analytics to better inform decisions regarding PSPS events, as well as outage/curtailment decisions related to transmission.

In 2022, PGE is developing the model architecture and sourcing the required data to implement a risk-based predictive analytical approach to meteorological modeling. The purpose of this project is to provide more granular and sophisticated inputs to PGE's PSPS decision analysis, as well as its system alarming.

Risk Analysis for Vegetation Management

Primarily focused on inspection and maintenance activities in the high fire risk portions of PGE's service territory, as identified through PGE's HRFZ assessment process, PGE's Vegetation Management strategy includes both cyclical, routine inspections and maintenance of the entire PGE transmission system and Advanced Wildfire Risk Reduction (AWRR) activities driven by PGE's wildfire risk analytics. Specific, year-to-year vegetation management activities are guided by PGE's Risk Assessment Program, data from PGE's Remote Sensing Pilot Project (which uses LiDAR and hyperspectral imagery to precisely monitor vegetation density and proximity to PGE assets), and annual vegetation surveys. AWRR crews follow program trim specifications, which include increased removal rates and enhanced vegetation control techniques, discussed in more detail in Section 9, Vegetation Management, below.

Risk Analysis for System Hardening

PGE continues to leverage its Strategic Asset Management (SAM) utility wildfire risk methodology and Wildfire Construction Standards to harden the transmission and distribution (T&D) system within its HRFZs. PGE's system hardening activities are designed to accomplish three goals:

- Reduce the risk of potential wildfire ignition caused by PGE facilities
- Reduce the impacts of a wildfire on PGE's assets by installing system hardening technologies (fire mesh, ductile iron poles, fiberglass crossarms)
- Protect utility infrastructure during potentially disruptive natural and human-caused disasters, supporting PGE's ability to maintain and restore reliable electrical service to support disaster relief and public safety.

In working towards these goals, PGE will deploy additional reliability improvements within the HRFZs. PGE is guided by its Wildfire Construction Standards in conducting equipment replacement in HRFZs. As outlined in PGE's Wildfire Construction Standards, the company will evaluate the following assets, with input from PGE subject matter experts, for replacement or implementation when warranted:

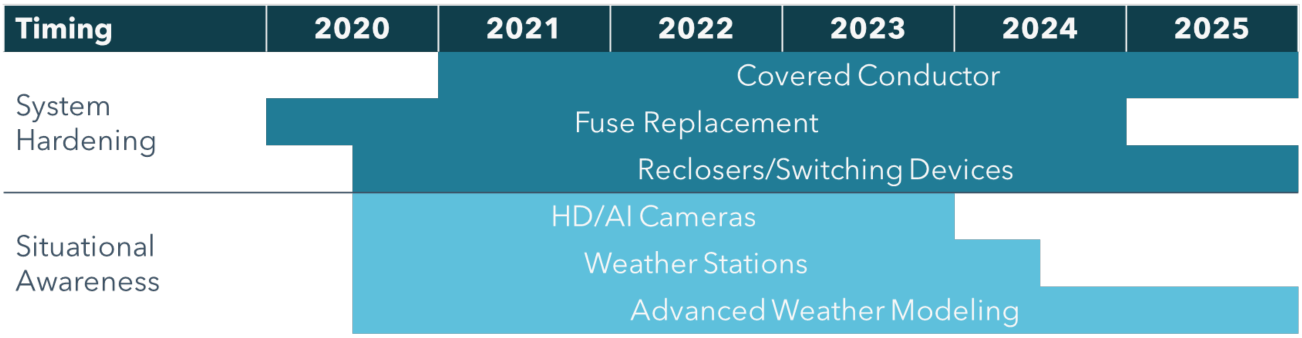
- Undersized/aging conductors in HRFZs
- Tree wire, an insulated overhead conductor designed to reduce service interruptions, which also reduces the potential for the conductor to become an ignition source
- Fuse replacement with non-expulsion fuses to eliminate a potential ignition source
- Viper reclosers and switching devices to increase operational flexibility and minimize customer impacts through the application of wildfire operational settings.

Risk Analysis for Investment Decisions

PGE is also revising its capital investment strategy to align with its ongoing analysis of risk velocity over time. The goal of this effort is to create a multi-year investment framework to implement these separate but interrelated mitigation strategies, based on a risk profile that incorporates all wildfire risk drivers (such as vegetation contact). This multi-year investment strategy will help PGE balance system hardening mitigation measures with speed of execution.

Figure 6 below shows the multiple system hardening and situational awareness investment programs currently included in PGE's multi-year wildfire risk mitigation investment strategy, through 2025.

FIGURE 6: PLANNED WILDFIRE SYSTEM HARDENING & SITUATIONAL AWARENESS INVESTMENTS, 2020-2025



PGE's multi-year investment strategy articulates a gradual increase in capital spending, distributed among multiple asset types. Table 3, below, describes PGE's planned capital project investment types, together with estimated quantities. PGE will begin scoping these capital project investments in 2022. In addition to these asset replacements, PGE will begin scoping potential undergrounding areas. These investments (including undergrounding) will be prioritized in alignment with PGE's wildfire investment strategy, which ranks system hardening and situational awareness projects identified as the highest value risk mitigation projects per dollar of investment.

TABLE 3: PLANNED WILDFIRE-RELATED CAPITAL INVESTMENTS, 2022

Asset	Quantity
Wildfire Cameras	10
Intelligent Reclosers	40
Weather Stations	23
Non-expulsion Fuses	480
Aluminum-Conductor Steel Reinforced Cable (ACSR)/Tree Wire	8 Miles

Risk Analysis for Operations

PGE relies on a wide variety of weather and fuel models to obtain the granularity of information required to forecast hazardous fire weather conditions 7-10 days in advance of potential events. These models can provide decision-makers with a detailed understanding of the uncertainties and range of outcomes possible for a given weather pattern. In addition, PGE is in the process of developing a real-time wildfire weather risk tool that will incorporate weather data from across the PGE service territory. When completed, this tool will significantly improve PGE's situational awareness capabilities. In addition, as part of its wildfire risk analysis, PGE annually reviews its HRFZs and updates its Community Resource Centers (CRC) Plan to reflect any changes to the list of HRFZs within PGE's service territory.

5.9 Equipment and Design Standards

PGE conducts an annual review of the Wildfire Construction Standard, which describes the current PGE-standard methods and materials for poles, conductor, crossarms, insulators and cutouts located within HRFZs. This annual update process documents and implements any wildfire-related changes identified during the post-wildfire season review process. In the past, this process has resulted in changes to the PGE equipment and design standards governing the use of ductile iron poles, fiberglass crossarms, and wildfire-safe fusing.

Section 6. Operating Protocols

6.1 Fire Season

Federal, Tribal, State and local authorities define fire season as the period(s) of the year when wildland fires are likely to occur, spread, and affect resource values sufficiently to warrant organized fire management activities. During this period, jurisdictional authorities regulate specific activities on public and private lands to mitigate the risk of human-caused ignitions. PGE declares its own fire season start and end dates and takes into account the State and Tribal fire season declarations.

PGE's fire season declaration and recission dates vary from year to year, depending on a variety of factors such as current and forecasted weather, drought status/timing and intensity, fuel availably and flammability, agency posture, and regional fire activity. PGE bases fire season timing decisions on data and information from multiple sources -- for example, the National Interagency Coordination Center (NICC), Northwest Coordination Center (NWCC), Climate Prediction Center (CPC), ODF, and Federal/Tribal Fire Management Officers and State District Foresters.

Fire season is divided into two "areas:" east of the Cascade Crest, and west of the Cascade Crest. This distinction is driven by historical differences in burning conditions such as weather patterns, fuel types and fuel moisture, in the two areas. This approach allows PGE to operate its system based on a more granular assessment of current and predicted fire danger, while maintaining system reliability in areas where fire risk is lower.

The historically fire-prone areas east of the Cascade Crest experience longer fire seasons, on average, than westside forests. On the east side, fuel differences, lower annual precipitation, and drought severity create favorable burning conditions from May through October. While decades of fire exclusion (management actions and policies designed to lower the risk of wildfire, such as understory clearing or dead tree removal) east of the Cascades have made them less resilient to fire, the westside forests are experiencing rapidly altering fire regimes. The region can no longer count on the brief summers and moist growing conditions during most of the year that produced reliably short-lived westside fire seasons.

PGE's fire season declarations:

- Change how the company operates the PGE system, initiating fire-season-specific settings within parts of the grid, including disabling reclosing/testing capabilities, where applicable

- Initiate fire season operational work practices in the field
- Increase monitoring and reporting on meteorological and operational conditions and use of other technologies to provide near real-time fire-related situational awareness, and
- Initiate notifications to key external stakeholders (Public Safety Partners, Federal, State, Tribal, and local officials, city and county emergency managers) in accordance with OPUC protocols.

6.2 System Operations During Fire Season

Once the start of fire season has been declared, PGE implements operational changes to reduce the risk of ignitions caused by PGE infrastructure and activities. These system changes include manually blocking non-remote controlled non-Supervisory Control and Data Acquisition (SCADA) distribution reclosing devices in the HRFZs from automatically test-energizing circuits following temporary faults, such as momentary tree branch contacts and lightning strikes with no damage. Prior to re-energizing, PGE will patrol the downstream circuit.

PGE may also change settings outside of fire season, when the risk of wildfire danger is elevated, or when a Red Flag Warning is in effect. In these instances, PGE will proactively block automatic reclosing on SCADA-controlled devices within PGE's HRFZs.

PGE annually reviews and updates settings for protection and control devices located within PGE HRFZs. In 2022, PGE will continue to implement circuit breaker and recloser protections to minimize fault energy and effectively reduce the risk of utility-caused ignitions during fire season.

Additionally, the distribution feeders servicing PGE's HRFZs (those equipped with Schweitzer Engineering Laboratories (SEL) relays and SCADA) can be set to operate in a specialized wildfire protective mode. Most can be set to one of three modes: Normal, Wildfire or Red Flag. 13kV feeders without SEL relays rely on electronic reclosers' necessary protection settings: Normal, Wildfire and Red Flag mode.

The following table shows the distribution system operations inside and outside of fire season that provide the necessary protection settings for Normal, Wildfire and Red Flag mode.

TABLE 4 : DISTRIBUTION SYSTEM OPERATIONS IN AND OUT OF FIRE SEASON

Mode	Description	Reason
Normal	The feeder will have two attempts of reclosing (an automatic test energization of the circuit following a fault event) and instantaneous (relay trips instantly when a fault occurs, with no preprogrammed delay)	Maximize reliability
Fire Season	The feeder or electronic recloser will have one attempt of reclosing and trip on definite time instantaneous (a programmed delay before the relay trips).	Minimize risk of ignition
Red Flag Warning (during fire season)	The feeder or electronic recloser trips on definite time instantaneous and reclosing is blocked.	Minimize risk of ignition

NOTE: Some of the transmission lines located east of the Cascades that traverse HRFZs do not have three specialized wildfire protective modes.

TABLE 5 : PELTON & ROUND BUTTE TRANSMISSION SYSTEM OPERATIONS IN AND OUT OF FIRE SEASON

Mode	Description	Reason
Normal	2 recloses at Pelton, 1 reclose at Round Butte	Maximize reliability
Fire Season & Red Flag Warning	Reclosing is blocked -- they open and lock out without testing the circuit by auto-reclosing.	Minimize risk of ignition

6.3 Situational Awareness, Enhanced Monitoring and Communication

During fire season, PGE monitors and communicates regional weather and wildfire situation/status to operational leadership. Situational and conditional awareness monitoring informs PGE's operational and system changes during fire season, increasing safety and operational efficiency, so that operational decisions are based on the most accurate information available.

Year-round, PGE hosts a Daily (M-F) Operations Call. Should weather or other related events warrant communications outside the normal schedule, PGE may decide to convene the Daily Operations Call on weekends. This daily briefing during fire season includes, but is not limited to:

- Fire weather forecasts and fire potential specific to PGE's distribution and service territory
- Communicating any National Weather Service (NWS)-issued Fire Weather Watches and/or Red Flag Warnings
- Summary of regional fire activity, and
- Fuels status review by Fire Danger Rating Area (FDRA) or Predictive Service Area (PSA).

Additionally, PGE closely monitors changing or deteriorating conditions, regularly communicating critical updates to affected business units. To assist with this, PGE maintains working relationships with fire agencies, fire management officers, district foresters and dispatch centers at the Federal, Tribal, State and local level, including the Portland NWS. These partnerships provide PGE with specific, granular situational and conditional awareness, such as assistance with forecast modeling validation, fire suppression resource pre-positioning, and activity/growth updates for fires in proximity to PGE assets.

6.4 Communications and Field Operational Practices

With support from leadership, PGE field personnel are responsible for maintaining situational awareness of current fire weather conditions. PGE field crews and contractors working on behalf of PGE are required to brief on the daily fire weather zone forecast(s) during job-specific tailboard briefings.

PGE field crews are expected to understand and adhere to the statutes and standards set forth in relevant PGE procedures and guides. PGE crews and contractors working on behalf of PGE are also required to comply with or exceed requirements set by other authorities having jurisdiction, such as the Federal, Tribal, State and local agencies.

6.5 Enhanced Monitoring and Technology

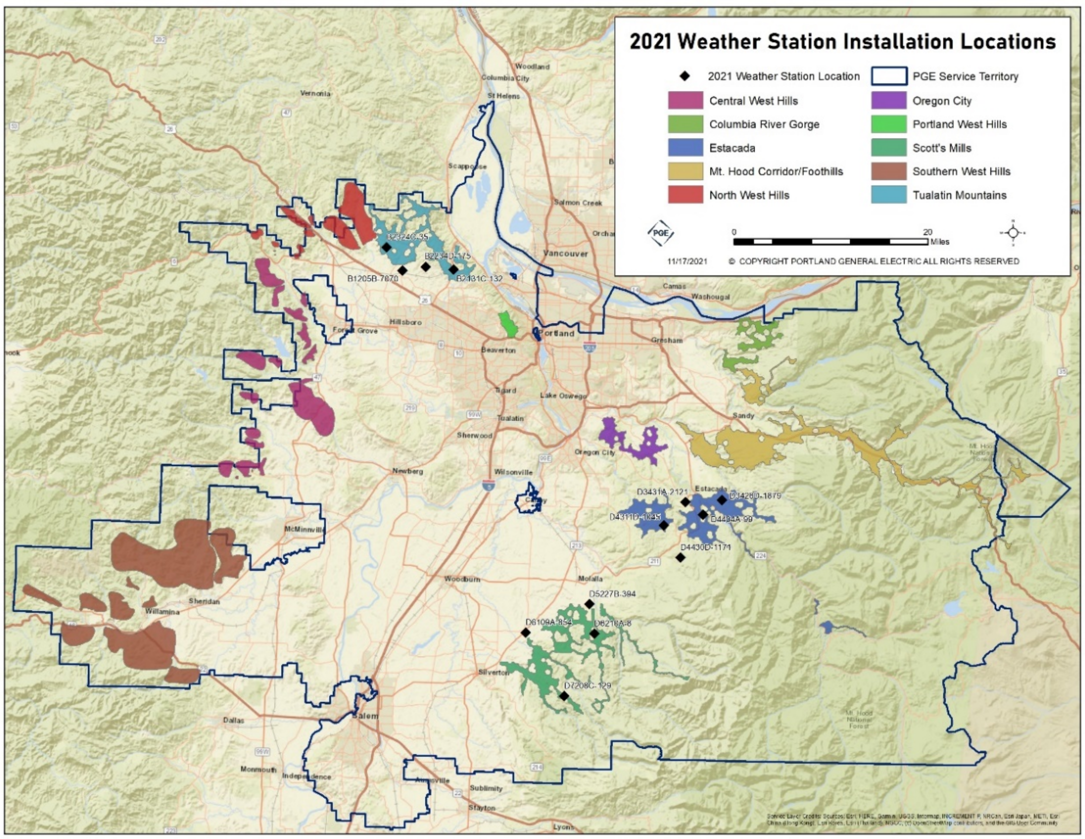
Declaration of PGE's fire season activates internal 24x7 Wildfire Threat Alert Notifications (Threat Alerts). Threat Alerts are a GIS-triggered, near-real-time analytical tool that alerts PGE when:

- Any fire incident has been confirmed by the Integrated Reporting of Wildland-Fire Information (IRWIN) service within one mile of a PGE facility in the last hour (five miles for PGE Parks)
- A Red Flag Warning has been issued covering an area within one mile of a PGE facility within the last 24 hours (five miles for PGE Parks), and

- A confirmed fire perimeter is updated by the National Interagency Fire Center (NIFC) within one mile of a PGE facility in the last hour (five miles for PGE Parks) in the event of an expanding wildfire.

In 2022, PGE will improve its situational awareness through the installation of 23 new remote automated weather stations (RAWS) along with four mobile weather stations to be deployed within its HRFZs. In addition, PGE is continuously enhancing these capabilities through partnerships with industry peers, fire agencies, fire management officers, and district foresters at the Federal, Tribal, State and local level, including the Portland NWS.

FIGURE 7: 2021 WEATHER STATIONS WITH HRFZ OVERLAY



In a partnership with the Electric Power Research Institute (EPRI), PGE has begun to build out a network of connected, intelligent fire detection cameras equipped with artificial intelligence. These ultra-high-definition camera systems give PGE a hyper-accurate, 360-degree fire detection triangulation capability across its service territory - down to +/- 100 yards accuracy. The platform's machine learning algorithms automate fire detection, awareness and notifications, helping PGE stretch limited resources. These camera systems are part of a larger situational awareness strategy in which PGE coordinates with Federal, State, Tribal and local fire agencies, fire management officers, and district foresters at the Federal, Tribal, State and local level, including private landowners.

6.6 Preparedness and Training

Prior to fire season, PGE provides annual wildfire refresher training to employees whose primary work responsibilities take them into the field. Participants receive training on the use of fire suppression tools and equipment, as they will be required to carry and safely use this equipment in the field. Contractors who perform work in the field on behalf of PGE must also satisfy this training requirement and carry fire suppression tools and equipment. Refresher training topics for 2022 include (but are not limited to):

- How fuels, weather and topography impact the ignition and spread of wildfires
- What a fire weather zone forecast is, how to interpret key factors and validate in the field
- The suppression tools and equipment PGE, and those acting on behalf of PGE, are required to carry
- Basic suppression tactics for low-intensity ground and surface fires, and
- How to identify lookouts, communications, escape routes and safety zones (LCES) and how this critical life safety acronym applies to all PGE fire season operations.

6.7 Event Response & Management

Separate from its PSPS plans, PGE has established protocols for emergent de-energizations, which can occur both within and outside of fire season. Emergent de-energization events occur when PGE must de-energize a circuit to allow Public Safety Partners at the scene to work safely – for example, during a structure fire or vehicle accident where energized electrical lines or equipment pose a hazard.

PGE personnel on-site have the authority to de-energize that portion of the distribution system without requesting permission from or notifying PGE management (for example: to de-energize a downed power line). In addition, first responders may request an emergent de-energization from PGE via 911.

PGE closely monitors active wildfires in or near its distribution service territory and generation asset areas in Oregon and Washington. As an incident expands in size and complexity, PGE will contact the agency Incident Management Team (IMT) and offer to embed utility representatives at the incident command post. Utility representatives are delegated authority to make decisions that align with PGE's Corporate Incident Management Team (CIMT) and company leadership on PGE's behalf. The goal of this strategy is to enhance interoperability, share information and promote collaboration to achieve shared objectives to serve the community and affected customers.

Depending on the fire's complexity and incident management structure, the utility representatives may report to the IMT's Liaison Officer, Safety Officer, Operations Section Chief, or Incident Commander. Utility representatives possess subject matter expertise in PGE's electrical energy system/infrastructure and wildland fire operations, are proficient in the incident command system

(ICS), and can seamlessly navigate and integrate with the agency IMT. Utility representative responsibilities include:

- Answer questions and providing strategic and tactical updates from PGE's CIMT related to outage response, damage assessment and restoration at agency planning and cooperation meetings
- Liaise with agency IMT participants and coordinating information exchange between the agency IMT and PGE's CIMT
- Provide information to the agency IMT on incident impacts to PGE infrastructure and potential outcomes, based on the agency IMT's tactical planning/operational period objectives
- Provide strategic and tactical updates to PGE's CIMT to inform key decisions related to outages, system reliability, communications, and community outreach
- Coordinate joint planning meetings between the agency IMT and PGE's CIMT Incident Commander, as needed, and
- Facilitate the transfer of PGE GIS data layers to the agency IMT's GIS Specialist to assist with the team's strategic and tactical planning.

6.8 Ignition Reporting Requirements

PGE tracks potential ignitions caused by PGE equipment, as well as fires that may impact PGE facilities. Relevant tracking and reporting include documentation of the initial observation and recording of ignition events in the field, as well as the specific geographic and right-of-way location of any impacted PGE equipment.

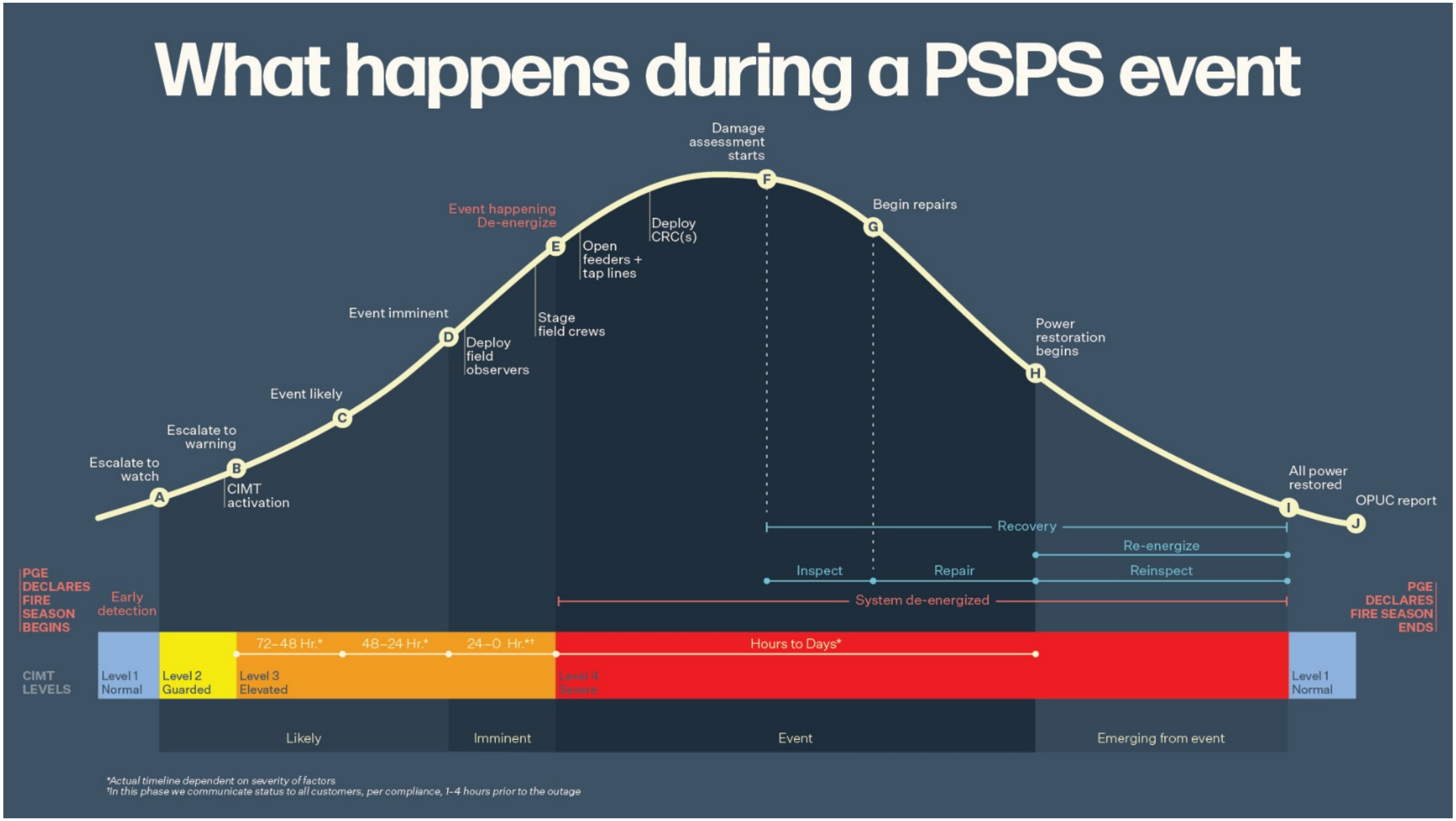
PGE conducts a review of any ignition events reported in the field, and documents relevant data for submission to the OPUC. In addition, PGE tracks and reports the progress of ignition event reports submitted to the OPUC and archives its OPUC ignition event reports for future compliance purposes. Historic ignition event data is used to inform strategic asset management decisions, including system hardening measures, with a more granular understanding of risk. PGE plans to continue to build out this ignition tracking/reporting database as a key component of understanding ignition events by drivers.

Section 7. Operations During PSPS Events

This section provides a high-level overview of the stages of a PSPS event and the actions taken within each step. PGE's detailed operational protocols for PSPS events are detailed in the annual PSPS Plan.

The PSPS Process Flowchart (Figure 8) correlates these different stages with the PGE incident levels defined in PGE's Corporate Emergency Operations Plan (CEOP) to illustrate the concept of operations for a PSPS event. It is intended to provide a point of reference only, as PGE will consider other conditions in its PSPS decision-making.

FIGURE 8: PSPS PROCESS FLOW CHART



7.1 Protocols for De-Energization of Power Lines and Power System Operations During PSPS Events

PGE will proactively turn off power when conditions threaten the ability to safely operate the grid, as a last-resort safety measure to protect people, property and public areas. When PSPS events are declared, PGE takes steps to minimize the number of customers affected and the duration of the outage.

7.2 Stages of a PSPS Event

Level 1: Normal (Early Detection)

Once fire season has been declared, PGE assumes a more heightened situational and conditional awareness posture. For a detailed explanation of PGE's situational awareness, monitoring and communications activities, refer to Section 6.5, Enhanced Monitoring and Technology. PGE will issue a PSPS Watch in response to its assessment of factors indicating an increased risk of ignitions.

Level 2: Guarded (PSPS Watch)

If PGE determines that current and predicted fire danger and conditions warrant an escalation in planning and coordination, PGE shifts from Normal to PSPS Watch condition. When this occurs, PGE will activate the CIMT Wildfire Assessment Team to monitor conditions and be prepared to initiate the next phase of PSPS plans and procedures if conditions warrant. During this phase of response, PGE also conducts daily conference calls to assess conditions and issues a preliminary notification to internal stakeholders and ESF-12 OPUC Safety Staff that PGE has moved to PSPS Watch status. See the PSPS Notification Strategies section, below, for a more detailed description of PSPS notification protocols. Following the decision to issue a PSPS Watch notification, PGE will place the CIMT on standby.

Level 3 Elevated (PSPS Warning)

PGE's decision to escalate to PSPS Warning status initiates several activities. The extent to which these activities are performed is dictated by conditions on the ground, pace of onset and risk tolerance at the time.

Once this decision is made, PGE will activate the CIMT, PGE's crisis management hub. PGE will notify required internal and external stakeholders via email and/or phone that a PSPS event could be imminent. PGE will communicate with Public Safety Partners and operators of utility-identified Critical Facilities at prescribed intervals (72-48, 48-24, and 4-1 hours in advance of the PSPS event). PGE will notify all other affected customers/populations directly, through the PGE website and an array of media and social media platforms, at 48-24 and 4-1 hours, and again when de-energization is initiated.

If conditions remain as predicted or worsen, PGE will make a final determination as to whether to proceed with the PSPS event.

The CIMT develops Incident Action Plans (IAPs) for each operational period (or as determined by the Incident Commander), including situation-specific tactics and detailed instructions for field and support personnel. The CIMT also mobilizes Field Observers (FOBS) and assigns them to identified, high-exposure locations within HRFZs where weather and system condition visibility is limited or absent. During this phase, PGE also prepares to deploy Community Resource Centers (CRCs), if warranted.

PGE will consider requests for a de-energization delay from its Public Safety Partners on a case-by-case basis. PGE retains ultimate authority to grant a delay and is responsible for determining how a delay in de-energization impacts public safety.

Level 4: PSPS Event

Immediately prior to de-energization, PGE resources in the field will move into their ready positions or at the staging area until needed. PGE will then implement the PSPS according to the protocols outlined in department tactical procedures. PGE will announce the start of the outage via the "All PGE" Talk Group, as well as the channels required by the OPUC.

During a PSPS outage event, PGE follows the OPUC PSPS notification protocols, providing updates as required, no less frequently than once every 24 hours, until service is restored. PGE will use direct contact, the portlandgeneral.com website, and an array of media and social media platforms to communicate information about the PSPS outage event and its status, as well as information regarding any CRCs deployed for the event.

Demobilization and Recovery

Once hazardous conditions subside, PGE will direct field crews to begin inspecting transmission and distribution circuits and other PGE assets impacted by the event. Field resources will conduct inspections, report conditions to PGE leadership, and initiate any required repairs. As soon as it is safe to do so, PGE will begin power restoration. PGE will issue updates on re-energization progress at least once every 24 hours. Once power is fully restored, PGE will alert Public Safety Partners, operators of critical facilities, and all other affected customers.

Section 8. Asset Management and Inspections

PGE conducts inspections of transmission and distribution assets in HRFZs and implements strategic replacement projects in accordance with the annual Wildfire Mitigation Plan. PGE maintains an inspection cycle for HRFZ areas, combined with PGE's annual Facilities Inspection and Treatment to the National Electrical Safety Code (FITNES) inspection cycle, to inspect transmission and distribution circuits within PGE's HRFZs annually.

The purpose of PGE's asset inspections is to enhance the safety and reliability of PGE's 12,000-mile system and the wildfire resilience of PGE's transmission and distribution systems, through maintenance, asset replacement and upgrades.

8.1 Routine Inspections and Maintenance

PGE operates periodic and time-based inspection programs and a preventative maintenance program to meet OPUC compliance requirements.

In 2021, PGE did foundational work to enable a more efficient wildfire inspection program, which will help PGE achieve its goal of completing inspections in all HRFZs prior to July 31, 2022. This work includes:

- Establishing the 2022 HRFZs early enough to assign resources and develop a viable inspection schedule
- Transitioning to an Inspect-Correct approach using two-person crews to inspect and repair most corrections and mitigate risk in a single visit to the pole
- Utilizing a competitive bid process to select a union signatory Inspect-Correct vendor
- Hiring dedicated wildfire inspection program resources, including a project manager and QA/QC field personnel, and
- Building a robust technology tool that enables mobile inspections and dashboard creation to track inspection progress.

FIGURE 9: PGE INSPECT-CORRECT CREW REPAIRS AND INSPECTIONS USING HIGH-POWER SPOTTING SCOPE

8.2 Inspection Program Overview

PGE's longstanding FITNES program is designed to conduct detailed inspections of its overhead facilities to identify violations of OPUC Safety Rules. FITNES performs a detailed inspection of approximately 10 percent of PGE's poles and related overhead facilities each year. FITNES inspectors visually inspect structure and support systems (poles, crossarms, insulators, guys, anchors), grounding, conductor clearances and condition, among other parameters, as well as hammer sounding or measuring remaining pole shell from grade to six feet above grade. Poles older than five years also receive remedial internal treatment. The FITNES inspection is performed by contract inspection personnel who walk PGE's overhead electric supply lines.

PGE also conducts an annual safety patrol of 50% of the entire PGE system to meet OPUC requirements, including routine safety patrols of overhead electric supply lines and accessible facilities for hazards to the public at least every two years. The safety patrol is performed by PGE inspectors who observe overhead supply lines and related accessible facilities and inspect for conditions that may pose a hazard to the public. These conditions include, but are not limited to, broken poles, structures with external decay, broken or severely split cross arms, broken-down guys, vegetation such as ivy growing more than halfway up poles, low conductors, conductors off insulator, broken insulators, broken conduits and anchors pulled out of the ground.

In addition to wildfire mitigation inspections, PGE performs a variety of routine inspection and maintenance activities throughout the calendar year. PGE's annual 230kV and 500kV safety inspections are conducted via helicopters crewed by journeymen linemen, who look for any high-level hazards. PGE's 57kV and 115kV lines also undergo an annual safety inspection through a mix of air and vehicle patrols.

During the ground/infrared patrol process, PGE subjects its 230kV and 500kV lines to an intensive walking inspection of each structure, looking for any defects. During the infrared patrol, conducted on the same schedule, PGE uses infrared-cameras to examine all junction points (splices, switches, jumpers) on energized lines, looking for any thermal anomalies. PGE conducts non-scheduled troubleshooting patrols as needed to find the source of an outage or unexplained occurrence; whenever possible, crews will repair the cause of the outage on the spot.

TABLE 6: INSPECTION/PATROL FREQUENCY

Asset Type	Air Patrol (Safety)	Vehicle Patrol (Safety)	Ground Patrol / IR Patrol**	Wildfire Inspection****	FITNES Inspection
230kV and 500kV* Lattice/Steel	Semi-annually	Semi-annually	Every 5 years	Annually	N/A
230kV Wood*	Semi-annual	Semi-annual	Every 5 years	Annually	Every 10 years
115kV ***	Annually	Annually	Every 10 years	Annually	Every 10 years
57kV ***	Annually	Annually	Every 10 years	Annually	Every 10 years
* Two Safety patrols per year, can be a combination of vehicle or air patrols.					
** Ground patrols are scheduled on a 5-year offset from FITNES patrols where possible.					
*** One safety patrol per year. Can be either a vehicle or air patrol depending on access and flight restrictions.					
**** Only for those portions of the line that are identified to be within an HRFZ					

8.3 Enhanced FITNES Wildfire Mitigation Inspections for HRFZs

PGE's Wildfire Mitigation Inspection program was established in 2019. Continuing in 2022, PGE will track Inspect-Correct progress within the HRFZs using a new geospatial platform, ArcGIS Online. Real-time metrics available via the ArcGIS Online dashboard include completed pole inspections by HRFZs, total completed pole inspections, and completed two-person inspections.

PGE documents its Inspect-Correct workflow through a master schedule, which also considers the coverage area of the annual FITNES inspection to avoid overlap. PGE's goal is to complete as many inspections as possible in the HRFZs by July 31, 2022 in accordance with the following schedule:

- Inspect the three new 2022 HRFZs (HRFZs 8, 9 and 10) first, as this will be the first time they have been subject to the more intensive Wildfire Mitigation Inspect-Correct inspection process: during February-April 2022
- HRFZs 1 through 7 and transmission lines in elevated fire risk zones in Central Oregon: April-July 2022.

In 2022, PGE will inspect all overhead facilities within its HRFZs and has identified multiple transmission circuits within its HRFZs that will be subject to an enhanced inspection process because of their crucial importance to system reliability during PSPS events.

Inspection Process

PGE's Wildfire Mitigation inspectors visually inspect structures, lines and equipment from the ground using binoculars or a spotting scope mounted on a tripod. In addition, PGE transmission patrolmen patrol and inspect the transmission lines in the Central Oregon HRFZ (which lies outside the PGE service territory but is subject to the same wildfire mitigation inspection criteria as PGE's other HRFZs) to identify potential vegetation management, structural or maintenance issues. Because PGE annually operates multiple separate asset and vegetation management inspection programs, assets located within PGE HRFZs may be inspected more than once a year.

PGE inspectors use a standardized form to consistently and repeatably capture target conditions during field inspections. This form is informed by both regulation and PGE equipment standards. The major categories PGE inspects for include:

- Damaged/ broken/missing/loose hardware and equipment
- Conductor clearances
- Bonding
- Damaged poles
- Broken lashing wire
- Potential ignition sources.

Justified Enhanced Inspections

Inspections are most beneficial in cases where wildfire consequences are high, and the condition of equipment is uncertain. PGE's Risk Assessment model calculates the value of enhanced inspections using asset risk and condition data, as well as length of time since the equipment was last inspected.

Wildfire Correction Criteria

PGE categorizes wildfire corrections as follows:

- An asset that poses an imminent danger to life or property will be repaired, disconnected, or isolated by the operator immediately after discovery
- An asset that poses a hazard will be corrected as soon as practicable but no later than 30 days after discovery, and
- PGE will address all other assets in accordance with OPUC requirements.

Section 9. Vegetation Management

PGE's vegetation management strategy has two major components: PGE's Routine Vegetation Management program and the Advanced Wildfire Risk Reduction (AWRR) program. Due to the expansion of PGE's vegetation management work at the core of this Wildfire Mitigation Plan, and the increase in the number of 2022 HRFZs, which contain more than 250 additional circuit-miles of assets, PGE is taking a phased approach to implementation of its AWRR work within the HRFZs. One of the primary goals of PGE's vegetation management program is to complete the inspection and mitigation process within all HRFZs annually, prior to July 1.

9.1 Routine Inspection & Maintenance - Vegetation Management

Under the Routine Vegetation Management program, PGE manages approximately 2.4 million trees within its ROW of 12,000 miles of overhead power lines, and has expanded its vegetation management program to trim and remove vegetation that is dead, dying, diseased or displays growth habits or defects that could impact overhead power lines within the ROW and easement. About 10,000 line-miles of PGE's 12,000 line-mile overhead network require regular vegetation management inspection (the other 2,000 miles pass over areas with no potentially hazardous vegetation, such as water).

PGE inspects about one-third of its overhead transmission assets annually. Assets are inspected no less frequently than every three years. Routine inspection timing may change as PGE evaluates the effectiveness of its Vegetation Management cycles. Routine Vegetation Management inspections identify both P1 and P2 trees. A "P1" tree is a hazard/danger tree, while a "P2" tree is a tree that poses a grow-in or fall-in threat and displays arboricultural defects that could pose risk to PGE's facilities, both overhead and underground.

PGE conducts its routine vegetation management activities year-round throughout the PGE overhead system. PGE vegetation contractors trim identified trees to PGE specifications during the three-year Routine Maintenance cycle, to comply with Oregon Administrative Rules (OAR) Division 24 Safety Standards (Division 24), other state standards, and ANSI A300 guidance.

PGE subjects its vegetation management activities to a detailed QA/QC process to verify that vegetation management tasks have been completed to specification, and tasks are tracked through PGE's vegetation management technology platform, QuickBase. In addition, this work is field-validated by PGE forestry personnel, who work closely with the crews to confirm completion. To increase their effectiveness, PGE also coordinates its vegetation management activities closely with external stakeholders, including USFS, ODF and private landowners.

9.2 Advanced Wildfire Risk Reduction (AWRR) Vegetation Management Program for High-Risk Areas

Under the AWRR program, PGE performs annual vegetation inspections of all overhead line mileage that falls within HRFZ areas, optimizes vegetation management strategies based upon inspection results, performs QA/QC of vegetation management inspection and mitigation work completed by crews, documents its vegetation management activities and coordinates vegetation management activities with counties, municipalities, and external agencies (e.g., ODOT, USFS).

PGE's AWRR has multiple components, providing annually occurring inspections/work templates of all designated overhead (OH) line mileage, as well as ongoing cyclical work aimed at providing more robust hardening of specific segments or spans of designated overhead line.

PGE follows ORS 758.280-758.286 to provide the operational framework for AWRR-related activities, as most of this work is occurring outside of designated PGE ROW, utility easements and annual maintenance schedules.

PGE manages the AWRR program, from work schedule to QA/QC of completed work. AWRR activities are in addition to PGE's annual vegetation management cycle; its vegetation prescriptions follow program specifications, which include more frequent inspection and maintenance cycles and enhanced tree removal guidelines than those required by OAR Division 24.

Tree removal practices associated with AWRR are applicable to any tree within striking distance, regardless of current tree health conditions. AWRR operations fall outside of PGE's routine maintenance and trimming operations as the scope, operational practices, inspection schedule and cadence are on escalated cycles. The AWRR program complements PGE's Routine Maintenance Program by focusing on results from PGE's Wildfire Risk Assessment modeling program.

FIGURE 10: HELICOPTER VEGETATION MANAGEMENT

FIGURE 11: FORESTRY BUCKET AND TREE-TRIMMING CREW ON AWRR DEPLOYMENT

9.3 Inspection & Maintenance Frequencies for AWRR

TABLE 7: PGE HRFZ INSPECTION & MAINTENANCE STRATEGIES

AWRR Mitigation	Inspection or Maintenance?	Cadence	Description
Vegetation Inspection	Inspection	Once per year prior to fire season declaration	Verifies ongoing vegetation clearance compliance and identifies any vegetation that has encroached on PGE assets since the previous inspection. These AWRR inspections occur annually, outside of PGE's standard 3-year vegetation maintenance cycle.
Cycle Buster Tree Trimming*	Maintenance	Once per year prior to fire season declaration	As PGE Vegetation Management inspectors identify "cycle-buster" vegetation through the AWRR program, off-cycle tree crews are dispatched to trim the vegetation back to specification.

Enhanced Vegetation Management (EVM) Techniques*	Maintenance	Annual	PGE often prescribes vegetation control techniques for AWRR projects that exceed standard line-clearance specifications. These prescriptions include greater side-clearance, overhang removal, selective removal of tree parts, and whole tree removal.

*NOTE: PGE plans to complete the AWRR Cycle Buster and Enhanced Vegetation Management work planned for 2022. Due to the recent increase in the number and scope of HRFZs for 2022, it may not be possible to complete all of this work in the newly identified HRFZs prior to July 1. PGE's Vegetation Management, Cycle Buster tree trimming, and Enhanced Vegetation Management work will continue throughout 2022.

9.4 2022 Planned Vegetation Management in High-Risk Fire Zones

Due to the 2022 numerical and geographic expansion of PGE's HRFZs and the time and effort required to prepare for fire season, not all work identified in this plan will be completed in advance of fire season. PGE expects that Enhanced Vegetation Management and inspection work will be ongoing throughout the year.

The following section describes wildfire mitigation work PGE plans to undertake in 2022:

- P1 inspection and mitigation of all HRFZ overhead line mileage.
    - P1 vegetation will be mitigated within 24 hours of identification, except in special circumstances (specialized equipment or line clearances needed). ASAP scheduling will occur under special circumstances should specialized equipment or specialized crews be needed
- 275 additional circuit-miles of P2 scoping (full AWRR scope – mitigation of P1, P2 and vegetation growth within 5 feet of conductor - in HRFZs 1,4,5) beginning in July and continuing through 2023.

NOTE: This scope and timeline may change once the State of Oregon's fire map is made available.

Section 10. Wildfire Program Costs

Budgeted development, implementation and administrative costs specifically for PGE's 2022 Wildfire Mitigation Program include the following:

2022 Wildfire-Related Operations & Maintenance (O&M) Forecasted Costs: $22 million

Includes (but is not limited to):

- Additional wildfire-related vegetation management costs
- Community Resource Center costs
- Wildfire training
- Additional wildfire-related outreach and education costs, and
- Wildfire-related staff.

2022 Wildfire-Related Capital Forecasted Costs: $10 million

Includes (but is not limited to):

- Additional asset inspection and repair contract costs
- Additional situational awareness tools, including weather station and AI-enabled UHD camera deployment, and
- Wildfire-related transmission maintenance and capital replacement work.

NOTE: The wildfire-related O&M and Capital budgets are in addition to the expenditures PGE makes annually to operate and invest in the grid.

PGE's Wildfire Program, as articulated in the Wildfire Risk Mitigation and Operating Protocols sections of this Plan, will influence the Wildfire program's resource allocation decisions. PGE understands that all cost category programs have varying levels of impact to wildfire mitigation, and that effectiveness has been well-captured through peer utility lessons learned and international forums related to wildfire. For example, the experience of other utilities might provide PGE with insights into the effectiveness of drone use in asset health inspections, their influence and timing on a utility's wildfire risk analysis, and some sense of the anticipated lifecycle costs for that activity, allowing PGE to make a comparative decision on this aspect of the wildfire mitigation program.

PGE's risk-based cost and benefit analysis connects the many components of PGE's wildfire risk management strategy, from system hardening to vegetation management to situational awareness. The comparative risk mitigation value of these actions can be measured using the ISO-31000 framework, allowing PGE to make investment prioritization decisions that deliver the most mitigation value to customers and the region.

Section 11. Community Outreach and Public Awareness

PGE has an overarching wildfire outreach and public awareness strategy comprised of:

- Wildfire Mitigation Plan Engagement Strategy
- Wildfire Information and Awareness Strategy
- Public Safety Partner Coordination Strategy, and
- Public Safety Power Shutoff Notification Strategy.

FIGURE 12: 2022 WILDFIRE MITIGATION PLAN ENGAGEMENT STRATEGIES

Goals and objectives of PGE's Wildfire Outreach and Public Awareness efforts include:

- Protect people, property and the natural environment
- Engage and collaborate with Public Safety Partners, local communities, customers, and owners of PGE-identified critical facilities in an inclusive process to facilitate life safety and incident stabilization, and leverage Diversity, Equity and Inclusion (DEI) principles to ensure continuity of agency services
- Improve critical infrastructure resilience through planning and coordination with external agencies
- Improve coordination of emergency response, situational and conditional awareness
- Enhance PGE's wildfire planning, prevention and response through coordination, communication, and collaboration with external partners
- Improve understanding of external stakeholder vulnerabilities and values-at-risk (economic, social, and ecological resources that could be damaged because of a wildfire)
- Educate external stakeholders on wildfire preparedness and potential consequences to critical infrastructure from wildfires
- Promote learning and adaptation during and after exercises and incidents

- Facilitate the continuity of emergency services during grey and blue-sky events.

11.1 Wildfire Mitigation Plan Engagement Strategy

As part of the annual Wildfire Mitigation Plan update process, PGE engages and collaborates with Public Safety Partners and local communities in accordance with an inclusive engagement strategy. PGE's works with Public Safety Partners as conduits to local communities, and pursues direct engagement in instances when a Public Safety Partner's reach may not be sufficient. In 2022, PGE will host at least one public workshop to review and comment on the 2022 PGE Wildfire Mitigation Plan. Following the public workshop(s), PGE will distribute a survey to collect additional feedback regarding the Plan and engagement process. More information about PGE's Wildfire Mitigation Plan engagement strategies is detailed in Table 8.

TABLE 8: WILDFIRE MITIGATION PLAN ENGAGEMENT STRATEGIES

Partner Category by Activity	Public Safety Partners	Priority Partners	Local Communities and Customers

Outreach	Public Safety Partner-specific PGE team engagement
	• OPUC Safety / ESF-12, County Emergency Managers, ODHS
	  ○ PGE presentations
	  ○ PGE workshop facilitation
		Public Safety Partner-specific PGE team engagement
		• Local Governments, Critical Facilities, Energy Providers
		  ○ PGE presentations
			• Assess gaps in Public Safety Partner reach and engage Community-Based Organizations (CBO) or directly where appropriate
			• Prioritize 'access and functional needs populations', inclusive of medical certificate customers

Communications	• Develop education and awareness materials, informed by Public Safety Partners • Develop multi-modal, multi-lingual communications, informed by Public Safety Partners		
Accommodation	• Confirm via email the Public Safety Partners, Priority Partners and/or CBOs are willing and able to participate in this capacity • Provide accommodation to resource-constrained partners, where applicable		
Protocols	• Designate PGE staff who will call, email and capture learnings • Designate PGE staff backup if assigned PGE staff will be out of office during event		

Assessment	• Define metric tracking and reporting processes • Catalog learnings from pre, during, post-event activity

PGE is committed to applying an equity lens to promote accessibility and inclusivity and considers the needs of the populations it serves. As an example of PGE's commitment to inclusivity and accessibility, PGE co-authored the USDOE Energy Modernization Laboratory Consortium's white paper on "Advancing Equity in Utility Regulation," which included the following guidance regarding wildfire impacts:

> *"PGE's 's obligation to both serve and acknowledge disproportionate impact is realized, for instance, in our application of an equity lens to our wildfire mitigation efforts, and in particular the practice of proactively shutting off power in high-risk areas as a last-resort measure to protect communities against potential wildfire ignitions, called Public Safety Power Shutoffs (PSPS). PGE acknowledges that effective and inclusive communication with our vulnerable populations requires an approach that honors different modes, languages, and partnerships. As PGE is still learning where these customers live, we are seeking out and deferring to those with expertise and tenured relationships to serve as a two-way conduit for PSPS awareness and preparation."*

The paper notes that to achieve these goals, PGE has developed PSPS toolkits and communications in various modes (web, email, newsletter, social media) and languages - English, Arabic, Chinese (simplified), Chinese (traditional), Farsi, Japanese, Korean, Rohingya, Russian, Somali, Spanish, Swahili, and Vietnamese - to inform these populations as to how best to plan for a potential extended outage. Over 250 community partners were proactively contacted in mid-July 2021, provided the toolkit and asked if they were willing to serve as a conduit to their communities.

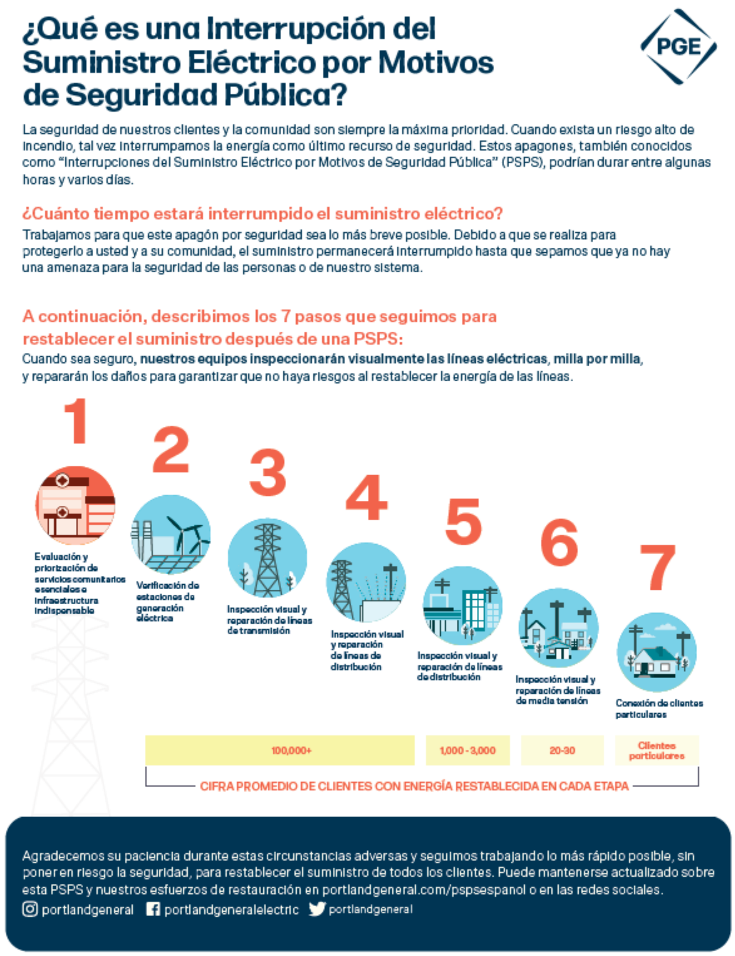
11.2 Wildfire Information & Awareness Strategy

PGE will engage with Public Safety Partners to develop/update a Wildfire Information and Awareness Strategy that is informed by local needs and best practices. Prior to the start of fire season, PGE will design and host an interactive workshop to elicit feedback from Public Safety Partners and their public information and outreach subject matter experts to ensure that the following activities are presented consistently and effectively across PGE's service area, and are responsive to the needs of each jurisdiction and their communities:

- Information about PSPS events: what a PSPS is, the factors PGE considers in determining whether or not to implement a PSPS and what to expect before, during and after a PSPS event
- Wildfire-related emergency kits, plans and checklists
- Wildfire-related educational and preparedness materials and messaging
- Messaging for meetings, fairs and workshops to discuss wildfire preparedness
- Assessment of most effective media channels to deliver strategic messaging.

PGE's messaging during PSPS events is provided in both English and Spanish, as is the messaging for PGE's email and direct mail wildfire/summer outage education and preparation campaign. These mailings are an essential part of PGE's Wildfire Information and Awareness Strategy; the materials direct customers to the portlandgeneral.com Wildfire Outages page (available in English and Spanish), PGE's primary educational and preparedness media platform. In addition, during PSPS events, PGE Customer Resource Centers distribute fliers in multiple languages, with the following message: "We speak your language. Our customer service advisors can assist you in 200+ languages. Call us at 503-228-6322."

FIGURE 13: "WHAT IS A PUBLIC SAFETY POWER SHUTOFF "—SPANISH VERSION



During fire season, the Wildfire Outages page on the portlandgeneral.com website provides information on the following topics:

- What is a Public Safety Power Shutoff?
- An interactive map of PGE's service territory and pre-identified PSPS areas, showing which zone (if any) is currently active. The map allows users to enter a service address to see whether it's located within the active zone
- How to prepare a home or business for a PSPS event

- A high-level overview of PGE's wildfire preparation/mitigation strategy
- Information regarding how PGE's HRFZs were identified
- PSPS FAQs
- Information regarding backup generators for use during a potential outage
- Planning recommendations for medically vulnerable customers.

PGE also provides PSPS preparedness checklists translated into multiple languages, available via the PGE website during fire season, as well as PSPS preparedness one-pagers to community-based organizations throughout the PGE service territory.

In addition to email and direct mail, PGE uses a full range of available communications channels to disseminate its wildfire and PSPS-related messaging: telephone/texts, social media, radio, television, and press releases. In 2022, PGE plans to build on its 2021 communications, education and preparedness campaigns, using these existing communications and educational channels as a baseline and working collaboratively with community leaders and Public Safety Partners to refine and update the direction and content as required to keep customers informed.

In 2022, PGE will perform information and awareness activities prior to and during the 2022 fire season to reach customers, Critical Facilities, local, State and Federal governments and elected officials, agencies, and Public Safety Partners.

11.3 Assessing Effectiveness of PGE Engagement Efforts

In 2022, PGE, in partnership with its Public Safety Partners, will seek equitable outcomes in its wildfire outreach activities. Those equitable outcomes include:

- Deliver wildfire mitigation information and awareness in an approachable and accessible manner.
- Empower Public Safety Partners with access to actionable information
- Engage and collaborate with Public Safety Partners and local communities in an inclusive and equitable way to help inform the WMP.

11.4 Public Safety Partner Coordination Strategy

PGE defines Public Safety Partners as the OPUC's Emergency Support Function (ESF)-12, Local Emergency Management, and Oregon Department of Human Services (ODHS). PGE's Public Safety Partner Coordination Strategy is divided into three phases: prior to, during, and after fire season. By working in partnership with each Public Safety Partner, PGE can maximize the effectiveness of its outreach efforts and the size of the audience receiving these communications, and improve operational coordination and information sharing.

Prior To Fire Season

Before fire season, PGE will engage in joint planning processes and deliver presentations to Public Safety Partners at existing information sharing and preparedness coordination forums, as needed. PGE will include wildfire preparedness topics in one of the PGE-hosted all-hazards quarterly summits with Public Safety Partners. PGE will work with Public Safety Partners to implement the Wildfire Education and Awareness Strategy to inform first responders and other critical service providers of PGE's coordination methods based on the National Incident Management System (NIMS).

PGE will also host at least one annual pre-fire season tabletop exercise with Public Safety Partners on a range of topics related to wildfire preparedness and response in accordance with Homeland Security Exercise and Evaluation Program (HSEEP) principles and guidelines.

When possible, PGE will engage in exercises developed by other Public Safety Partners to improve interoperability during an actual event.

During Fire Season

Once PGE declares Fire Season, the company will inform various Public Safety Partners regarding in-season operational modifications to the PGE system.

Additionally, PGE enhances situational awareness monitoring and maintains a state of operational readiness. Should a new fire start or expanding fire threaten PGE infrastructure, a company representative will contact the agency and/or Incident Management Team (IMT) identified point of contact to coordinate appropriate utility response. For all incidents, PGE acts as a cooperating partner when company infrastructure is at risk or has been impacted by a wildfire.

If an incident requires the activation of the PGE CIMT, PGE will notify impacted stakeholders and initiate in-person and virtual coordination activities. As required, PGE will deploy dedicated utility representatives to jurisdictional Emergency Operations Centers (EOCs), Emergency Coordination Centers (ECCs) or Incident Command Posts (ICPs).

Following wildfire incidents, PGE will conduct an After-Action Review (AAR) process that is consistent with HSEEP and utility sector best practices, reviewing incident response and identifying continuous improvement action items. Throughout the process, PGE will invite feedback from Public Safety Partners.

After Fire Season

When the 2022 fire season ends, Public Safety Partners will have the opportunity to participate in PGE's post-season review process. This process assesses progress towards the goals and objectives set out in the Wildfire Mitigation Plan. The lessons learned become an input to the annual Wildfire Mitigation Plan update.

TABLE 9: PUBLIC SAFETY PARTNER COORDINATION ELEMENTS

Activity	Execution Timing
Presentations to Public Safety Partners at existing information sharing and preparedness coordination forums	Prior to fire season
PGE-hosted tabletop exercise regarding wildfire preparedness and response	Prior to fire season
Direct communications to Public Safety Partners regarding current operations and collaboration needs	During fire season
Joint planning process with Public Safety Partners of PGE Wildfire Program and engagement strategy	After fire season
Post-season review participation by Public Safety Partners	After fire season

11.5 PSPS Notification Strategies

During periods of extreme weather, PGE may initiate a temporary PSPS event. The purpose of a PSPS is to reduce the risks of wildfire ignition within PGE's service territory and in areas adjacent to PGE critical infrastructure throughout the Northwest through proactive de-energization. Due to the disruptive nature of a power outage, PGE will execute PSPS events only when necessary.

Priority PSPS Notification to Public Safety Partners, Operators of Utility-Identified Critical Facilities and Adjacent Public Safety Partners

PGE recognizes the importance of effective communication to stakeholders during a PSPS event. PGE will, to the extent practical, provide priority notification to the following stakeholders 1) Public Safety Partners 2) operators of utility-identified Critical Facilities (including communications facilities), and 3) adjacent local Public Safety Partners. PGE will communicate to each of these respective stakeholders, at a minimum, the information indicated in the tables below.

PSPS Notification Channels

PGE will use owned and earned channels to inform customers and stakeholders throughout the PGE service area in line with the defined OPUC requirements, with special attention to those within the affected HRFZ. PGE will deliver notifications in multiple formats across multiple media channels that may include, but are not limited to, phone calls, text messages, reverse 911 partnership, social media posts, media advisories, emails, and messages to agencies that service other community populations. Details of the notifications are outlined in Table 10.

TABLE 10: PSPS NOTIFICATIONS

PSPS notifications to partners, customers and other stakeholders

	Warning	Likely	Imminent	Happening*	Restoration begins*	Restoration complete*
When:	**48–72 hours** before a PSPS	**24–48 hours** before a PSPS	**1–4 hours** before a PSPS	**During** a PSPS	When it's safe	PSPS is over
What:	We haven't made a final decision yet, but it's looking like a PSPS is possible.	We haven't made a final decision yet, but it's looking increasingly likely a PSPS will be necessary.	To protect lives and property, we expect to call a PSPS very soon. Now's the time to activate your emergency plan and be sure to keep your outage kit handy.	Power is being shut off. PGE may open a Community Resource Centers to provide essential resources like information, water, ice and a place to charge electronic devices.	Crews are patrolling and will respond to downed lines, repair damage and visually inspect equipment to make sure it's safe to restore power.	The immediate threat has passed and power has been restored. But we'll continue to monitor conditions so we can keep our customers and communities safe.
How you'll hear: (From us and emergency partners)	We will notify our partners (e.g. public safety partners, key government officials and critical facilities) via: • **Email/Phone** • **Other appropriate communication channels**	We, and our partners, will notify impacted customers, stakeholders and community-based organizations via: • **Email** • **Emergency Alert System** • **Text message** • **Social media** • **Updates on the PGE website** • **Media updates**	We, and our partners, will give impacted customers an estimated time when their power will be shut off via: • **Email** • **Emergency Alert System** • **Text message** • **Social media** • **Updates on the PGE website** • **Media updates**	We know this is challenging, so we'll do everything we can to stay in touch with impacted customers via: • **Email** • **Emergency Alert System** • **Social media** • **Updates on the PGE website** • **Media updates**	As crews work on restoration, we'll share any new or relevant information to make sure you're kept up to date via: • **Email** • **Emergency Alert System** • **Social media** • **Updates on the PGE website** • **Media updates**	When conditions stabilize and power has been restored, we'll notify impacted customers via: • **Email** • **Emergency Alert System** • **Social media** • **Updates on the PGE website** • **Media updates**

*PGE will provide status updates at least every 24 hours

Section 12. Participation in National and Regional Forums

Emergency managers from PGE, PacifiCorp, Northwest Natural Gas, and BPA collaborate throughout the year as part of an Energy Emergency Management Team (EEMT). Annually, the EEMT exchanges contact information with the Northwest Coordination Center (NWCC) for emergency communications during fire season. Dispatch/Control Center numbers provided by the energy companies are for dispatch-to-dispatch communications. Emergency management contacts are provided for both NWCC and fire dispatch center personnel to assist with strategic decision-making and incident coordination.

In addition, PGE annually participates in a variety of industry forums that may discuss wildfire-related topics, including:

- International Wildfire Mitigation & Resiliency Consortium: PGE participates with utilities from across the Western U.S., South America and Australia to benchmark and share best practices for wildfire mitigation
- Electric Power Research Institute (EPRI): PGE engages with its research partners at EPRI through multiple programs to address wildfire mitigation research, and is leveraging EPRI-led programs such as the Incubatenergy Network to gain knowledge of new technologies and start-ups in wildfire-related disciplines. As a result of its collaboration with EPRI, PGE deployed the Early Fault Detection pilot project in 2021
- Oregon Joint Use Association (OJUA): PGE is active in the OJUA, a non-profit industry workgroup whose mission involves building trust, cooperation, and organization between utility pole owners, users, and government entities to promote the safe, efficient use of the right-of-way. The OJUA has featured educational presentations at its meetings on the topic of Wildfire Mitigation
- Other National and Regional Forums: PGE is actively engaged with industry research partners at the Western Energy Institute, Edison Energy Institute (EEI), and the U.S. Department of Energy
- Regional Disaster Preparedness Organization (RDPO): PGE actively participates in the RDPO, which encompasses five Portland metro region counties – Multnomah, Washington, Clackamas, Columbia, and Clark - as a utility/energy sector participant and steering committee member. In this role, PGE provides the RDPO insights and a utility perspective on issues. In addition, PGE has garnered information related to regional disaster resilience and preparedness initiatives and to enhance regional partnerships.
- Oregon Conservation Corps: PGE sits on the Oregon Higher Education Coordinating Commission's Oregon Conservation Corps Advisory Committee, established through SB 762. The Oregon Conservation Corps Program grants funding to organizations across the state to aid in reducing wildfire risk to communities while also providing workforce training for youth and young adults.

Additionally, PGE serves as Co-Chair of EEI's Electricity Subsector Coordinating Council (ESCC) Wildfire Working Group (WWG). The ESCC is the principal liaison between the federal government and the electric power industry. In the fall of 2021, the WWG leadership team launched a new Wildfire Strike Team to address the most critical issues affecting successful wildfire land management and mitigation on federal lands. The Team includes representatives from PG&E, PacifiCorp, Idaho Power and Southern California Edison, BPA, USFS, EEI, the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA) and PGE in a key leadership role.

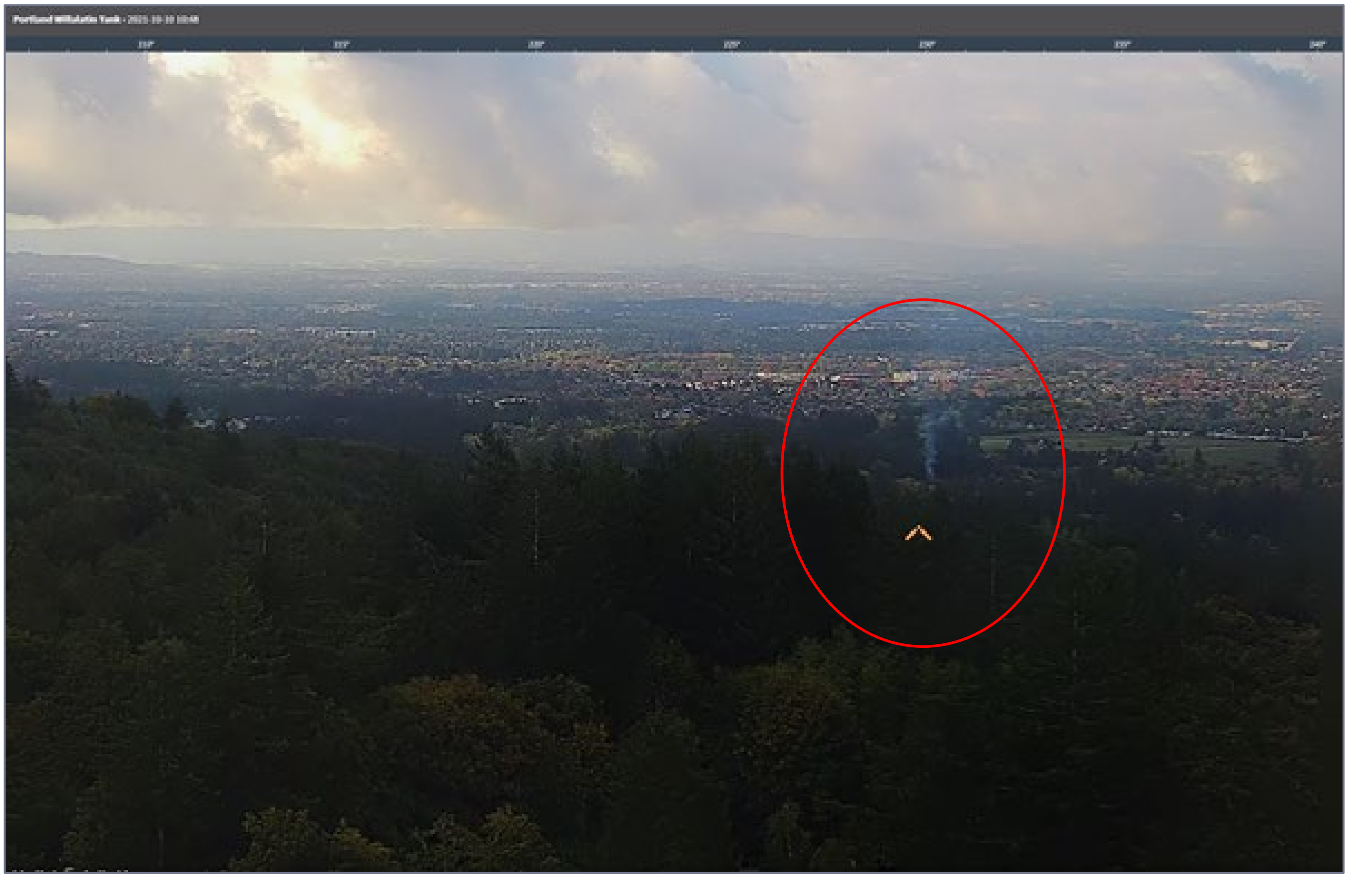
PGE is also working with Federal partners to support the Wildfire Strike Team's interdisciplinary and interagency efforts. PGE represented the utility sector in the President's 2021 wildfire meetings with cabinet secretaries to emphasize the need for continued leadership at the federal level on wildfires and shared responsibility on the matter, among other issues.

Section 13. Research & Development

PGE is undertaking a variety of wildfire-related research projects with public and private research institute and industry partners.

In 2021, PGE, in partnership with EPRI's Incubatenergy Network and the City of Portland, completed a demo project deploying two cameras equipped with artificial intelligence within PGE HRFZs. These cameras can detect and identify smoke through ultra-high-definition video imaging, and notify PGE if it detects a fire, in real time. The cameras are operational and detected multiple fires (not wildfires) in 2021. This technology shows promise in reducing response time and increasing situational awareness of any fires in the vicinity of PGE infrastructure, enhancing PGE's operational decision-making. In 2022, PGE plans to expand this technology to additional HRFZ locations, in collaboration with public and private agencies.

FIGURE 14: SMOKE DETECTED BY AI-EQUIPPED CAMERA SYSTEM



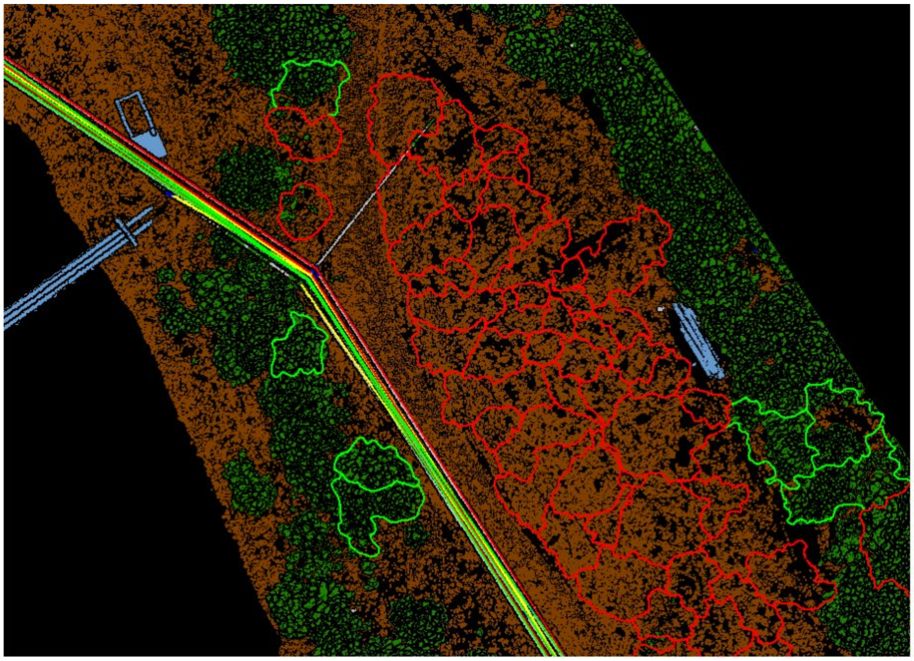
PGE is also conducting a Remote Sensing data acquisition project for the HRFZ feeders, to support wildfire and resiliency preparedness and operational design and engineering work beginning in 2022. The project will give PGE a more granular and precise understanding of vegetation risk, clearances to poles and wires, and right-of-way accessibility within the HRFZs than previous surveys have been able to provide. The Remote Sensing Pilot Project will also be used to inform PGE's capital planning work, which guides its wildfire investment strategy, and will help PGE understand how much risk has been mitigated through previous years' AWRR (vegetation management) efforts.

PGE's Remote Sensing Pilot Project also provides:

- GIS-enabled analyses of vegetation clearance and vegetation health
- A consolidated pole/span inventory
- A pole/span change detection analysis (2019-2021)
- A consolidated tree threat inventory (2019 and 2021)
- A tree change detection analysis (2019-2021).

When complete, the Remote Sensing Pilot Project will provide PGE with precise mobile and aerial LiDAR, spherical imagery and satellite multispectral imagery surveys of 774 circuit-miles of conductor and nearly 15,000 poles within the PGE HRFZs. It will be used to inform and refine PGE's asset and vegetation risk management activities beginning in 2022.

FIGURE 15: SAMPLE AERIAL LIDAR IMAGERY FROM REMOTE SENSING PROJECT



Areas outlined in red show trees identified as a threat in 2019 that have since been removed.

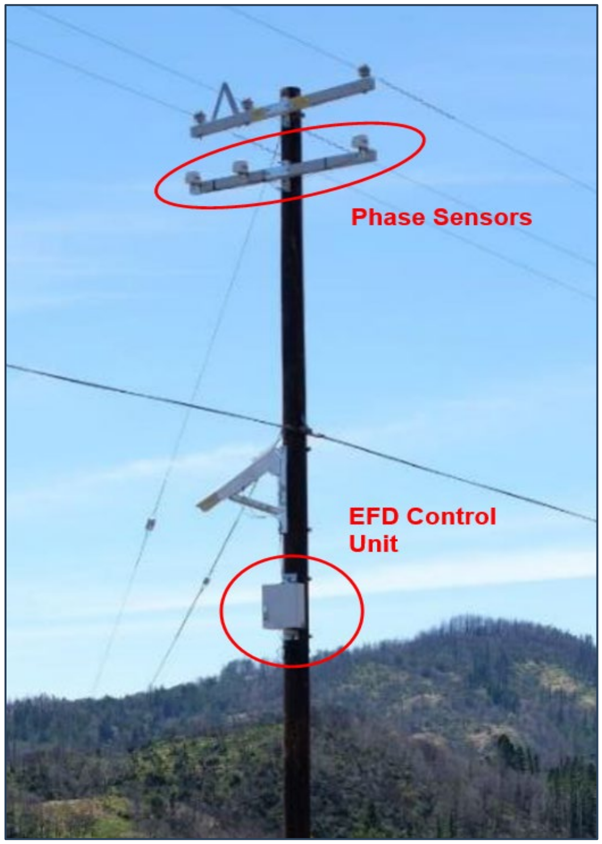
PGE is also leading the 5G PGE Energy Lab, focused on the development of innovative wildfire mitigation technologies. The collaboration is evaluating use cases and developing business cases for wildfire-related surveillance, sensing and data collection, and cloud storage technologies, laying the groundwork for the use of artificial intelligence-driven analysis in these disciplines. The group is also working on the creation of a 5G-enabled mobile network to improve mobile data collection and reporting. Field testing of the network began in November 2021; the group expects to complete field testing and identify which technologies to move forward with for deployment in December 2021.

In addition, results from its 2021 R&D pilot programs for intelligent faulted circuit indicators and smart reclosers have encouraged PGE to scale these technologies for additional field deployments in HRFZs in 2022 to improve system operations during fire season.

13.1 R&D Technology Under Evaluation – Early Fault Detection

In 2021, PGE deployed an Early Fault Detection (EFD) system that uses radio frequency signals to detect and pinpoint potential distribution system failures in PGE HRFZs. This technology, if successful, will pinpoint potential failure before traditional methods such as physical inspection. In 2022, PGE plans to complete deployment of the EFD pilot program and evaluate the suitability of EFD as a capital project, potentially expanding EFD deployment in HRFZs in 2022. PGE is developing processes to execute on alerts and data from the EFD systems, and to automatically create work orders.

FIGURE 16: EXAMPLE OF AN INSTALLED EFD SYSTEM



Section 14. Quality Control & Continuous Improvement

Following its end-of-fire-season declaration, PGE reviews fire season activities and events, collects and analyzes findings, produces a year-end report and tracks action items. This review is crucial to PGE's continuous improvement and documentation update processes and involves both internal and external stakeholders.

PGE assigns action items to the appropriate task owner, tracks action item progress through to completion, and reports progress to PGE's Executive Committees.

14.1 Post-Fire Season Review

PGE will conduct a review of this Plan with internal and external stakeholders following the annual end-of-fire-season declaration, as part of its formal post-fire season review process. This process typically includes, but is not limited to, the following objectives:

- Identifying aspects of the program (e.g., training, preparedness measures, operational strategies and documentation) that worked well

- Identifying opportunities to improve preparedness, operational strategies, training, work instructions, communication and other program elements
- Development of a narrative description of any changes to PGE's baseline wildfire risk analysis relative to the previous year's plan, as well as any specific actions PGE took in response to changes in baseline wildfire risk, seasonal wildfire risk and near-term wildfire risk
- Encouraging collaboration with Public Safety Partners and local communities in the annual review and update of the Wildfire Mitigation Plan, and in the identification of wildfire mitigation-related investments and activities
- Evaluating new ideas, improvements and observations identified by the team for future implementation
- Assigning task owners and target completion dates for corrective actions
- Identifying de-energization lessons learned, including a narrative description of each PSPS event that occurred during the previous year
- Identifying "next season" opportunities to improve collaboration with external stakeholders through planning, training and exercises, and
- Establishing baseline goals and objectives for the next fire season.

When an After-Action Review (AAR) is conducted due to the occurrence of a wildfire event, PGE will integrate any outstanding corrective actions into its post-fire season lessons learned review.

PGE will follow all relevant OPUC protocols in filing an annual report on de-energization lessons learned, providing a narrative description of all PSPS events which occurred during the fire season, by no later than December 31.

14.2 Monitoring & Audit

PGE's Internal Audit Services organization may provide assurance or advisory services related to this program in accordance with their annual audit plan as approved by the Audit and Risk Committee.

14.3 Annual Lessons Learned Process

At the end of each year, PGE conducts a wildfire review/lessons learned process that includes:

- Annual post-fire season review workshops involving both internal and external stakeholders
- Documentation and distribution of post-fire season lessons learned; identification of comments and recommendations to improve PGE's wildfire preparedness, system hardening and operational readiness
- Annual post-season review of PGE's wildfire mitigation performance metrics and targets
- Incorporation of lessons learned findings into the annual report, used to update PGE's Wildfire Mitigation Program and documentation, and
- Documentation of each year's lessons learned and year-end review findings, as well as performance metric outcomes, in PGE's Wildfire Program SharePoint library, for future reference.

Section 15. Contact PGE

For information regarding PGE's wildfire mitigation program, wildfire-related emergency kits, plans, and checklists, and wildfire-related education and preparedness information, please visit PGE's Wildfire Outages page or the PGE homepage (https://portlandgeneral.com) or call us at 1-800-542-8818. Current situational updates, outage status and wildfire information are also available via social media platforms (Facebook, Twitter, Instagram, and LinkedIn).

Appendices

Appendix 1. List of Tables

Appendix 2. List of Figures

Appendix 3. Glossary and Acronyms

AAR: After-Action Review

ANSI: American National Standards Institute

APPA: American Public Power Association

AWRR: Advanced Wildfire Risk Reduction

Blue Sky/Grey-Sky Events: A Blue-Sky event occurs when normal daily operations are executed for the community when natural disasters aren't occurring. A Grey-Sky event refers to events when a disaster occurs and all hands are on deck assisting with clients (victims of said disaster).

BPA: Bonneville Power Administration

CEOP: Corporate Emergency Operations Plan

CIMT: Corporate Emergency Management Team

CPC: Climate Prediction Center

CRC: Community Resource Center

Cycle Buster: Vegetation that will not make it through the routine trim cycle without encroaching on the required minimum clearances and, therefore require pruning midterm before the routine cycle is completed. PGE trims "cycle-buster" trees to increase clearances whenever they are encountered during the inspection cycle.

DEI: Diversity, Equity & Inclusion

ECC: Emergency Coordination Center

EEI: Edison Energy Institute

EEMT: Energy Emergency Management Team

EFD: Early Fault Detection

EOC: Emergency Operations Center

EPRI: Electric Power Research Institute

ESCC: Electricity Subsector Coordinating Council

ESF-12: Refers to Emergency Support Function-12 and indicates the Public Utility Commission of Oregon's role in supporting the State Office of Emergency Management for energy utilities' issues during an emergency, per OAR 860-300-0002(1).

FDRA: Fire Danger Rating Area

Fire Season: Period(s) of the year during which wildland fires are most likely to occur, spread, and affect resources sufficiently to warrant organized fire management activities

Fire Weather: Weather conditions that influence fire ignition, behavior and suppression

FITNES: Facilities Inspection & Treatment to National Electrical Safety Code

GIS: Geographic Information System

High Risk Fire Zone (HRFZ): Geographic areas at elevated risk of wildfire ignition identified by PGE in its risk-based wildfire plan

HRFZ: High-Risk Fire Zone

HSEEP: Homeland Security Exercise & Evaluation Program

IAM: Institute of Asset Management

IAP: Incident Action Plan

ICP: Incident Command Post

IMT: Incident management Team

IRWIN: Integrated Reporting of Wildland Fire Data

ISO: International Organization for Standardization

LCES: Lookouts, Communications, Escape Routes and Safety Zones

LiDAR: Light Detection & Ranging

Local Community: Any community of people living, or having rights or interests, in a distinct geographical area, per OAR 860-300-0002(2)

Local Emergency Management: Refers to city, county, and Tribal emergency management entities, per OAR 860-300-0002(3)

NICC: National Interagency Coordination Center

NIFC: National Interagency Fire Center

NIMS: National Incident Management System

No-Test Policy: PGE will disable auto-reclosing and not manually close-in a faulted circuit

NRECA: National Rural Electric Cooperative Association

NWCC: Northwest Coordination Center

NWS: National Weather Service

OAR: Oregon Administrative Rule

ODF: Oregon Department of Forestry

ODHS: Oregon Department of Human Services

ODOT: Oregon Department of Transportation

OH: Overhead (transmission or distribution circuit)

OJUA: Oregon Joint Use Association

O&M: Operations and Maintenance

OPUC: Public Utility Commission of Oregon

P1: Hazard/danger tree

P2: A tree that poses a grow-in or fall-in threat and displays arboricultural defect that poses risk to PGE facilities

PGE: Portland General Electric Company

PSA: Predictive Service Area

PSPS: Public Safety Power Shutoff

Public Safety Partners: Includes the ESF-12, Local Emergency Management, and Oregon Department of Human Services (ODHS), per OAR 860-300-0002(6)

QA/QC: Quality Assurance/Quality Control

RAWS: Remote Automated Weather Station

Red Flag Warning: A term used by fire-weather forecasters to call attention to limited weather conditions of particular importance that may result in extreme burning conditions. Red Flag Warnings are issued during ongoing events, or when the fire weather forecaster has a high degree of confidence that Red Flag criteria will occur within 24 hours of issuance. According to the National Weather Service, Red Flag Warnings will be issued whenever a geographical area has been in a dry spell for a week or two, or for a shorter period, if before spring green-up or after fall color, and the National Fire Danger Rating System (NFDRS) is high to extreme and all of the following weather parameters are forecasted to be met:

- Ten-hour fuels (moisture content of small vegetation that take only about 10 hours to respond to changes in moisture conditions) of 8 percent or less
- A sustained wind average 15 mph or greater.
- Relative humidity less than or equal to 25%.
- A temperature of greater than 75 degrees Fahrenheit.

In some states, dry lightning and unstable air are criteria. A Fire Weather Watch may be issued prior to the Red Flag Warning.

ROW: Right-of-way

SAM: Strategic Asset Management

SCADA: Supervisory Data Control & Acquisition

SEL: Schweitzer Engineering Laboratories

SME: Subject Matter Expert

Supervisory Control and Data Acquisition (SCADA): The control system architecture comprising computers, networked data communications and graphical user interfaces (GUI) for high-level process supervisory management, while also comprising other peripheral devices like programmable logic controllers (PLC) and discrete proportional-integral-derivative (PID) controllers to interface with process plant or machinery.

Striking Distance: A measurement that shows that a tree has the ability to fall into PGE's equipment, especially power lines

T&D: Transmission and Distribution

Tier 1 Risk: Describes an area where there is not an elevated or extreme risk of wildfires

Tier 2 (Elevated) Risk: Describes an area where there is an elevated risk (including likelihood and potential impacts on people and property) of utility-associated wildfires

Tier 3 (Extreme) Risk: Describes an area where there is an extreme risk (including likelihood and potential impacts on people and property) of utility-associated wildfires

USDOE: U.S. Department of Energy

USFS: U.S. Forest Service

Appendix 4: OPUC Phase 1 Wildfire Mitigation Rules In the WMP

AR 648 Phase 1 Wildfire Mitigation Rule Language	Where Addressed in PGE Wildfire Mitigation Plan
(a) Identified areas that are subject to a heightened risk of wildfire, including determinations for such conclusions, and are: *(A) Within the service territory of the Public Utility, and* *(B) Outside the service territory of the Public Utility but within the Public Utility's right-of way for generation and transmission assets.*	Section 5 (Wildfire Risk Mitigation Assessment Program Overview), pp. 10-22 Section 5.3 (High Risk Fire Zones), pp. 12-15
(b) Identified means of mitigating wildfire risk that reflects a reasonable balancing of mitigation costs with the resulting reduction of wildfire risk.	Section 5 (Wildfire Risk Mitigation Assessment Program Overview), pp 10-22
(c) Identified preventative actions and programs that the Public Utility will carry out to minimize the risk of utility facilities causing wildfire.	Section 5 (Wildfire Risk Mitigation Assessment Program Overview), pp. 10-22 Section 6: Operating Protocols, pp. 22-28 Section 7 (Operations During PSPS Events), pp. 28-31
(d) Discussion of outreach efforts to regional, state, and local entities, including municipalities regarding a protocol for the de-energization of power lines and adjusting power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure.	Section 7 (Operations During PSPS Events), pp. 28-31 Section 11 (Community Outreach & Public Awareness), pp. 41-48
(e) Identified protocol for the de-energization of power lines and adjusting of power system operations to mitigate wildfires, promote the safety of the public and first responders and preserve health and communication infrastructure.	Section 7 (Operations During PSPS Events), pp. 28-31
(f) Identification of the community outreach and public awareness efforts that the Public	Section 11 (Community Outreach & Public Awareness), pp. 41-48

AR 648 Phase 1 Wildfire Mitigation Rule Language	Where Addressed in PGE Wildfire Mitigation Plan
Utility will use before, during and after a wildfire season.	
(g) Description of procedures, standards, and time frames that the Public Utility will use to inspect utility infrastructure in areas the Public Utility identified as heightened risk of wildfire.	Section 8 (Asset Management & Inspections), pp. 31-35
(h) Description of the procedures, standards, and time frames that the Public Utility will use to carry out vegetation management in in areas the Public Utility identified as heightened risk of wildfire.	Section 9 (Vegetation Management), pp. 36-39
(i) Identification of the development, implementation, and administrative costs for the plan, which includes discussion of risk-based cost and benefit analysis, including consideration of technologies that offer co-benefits to the utility's system.	Section 10 (Wildfire Program Costs), p. 40
(j) Description of participation in national and international forums, including workshops identified in section 2, chapter 592, Oregon Laws 2021, as well as research and analysis the Public Utility has undertaken to maintain expertise in leading edge technologies and operational practices, as well as how such technologies and operational practices have been used develop implement cost effective wildfire mitigation solutions.	Section 12 (Participation in National & Regional Forums), pp. 49-50, and Section 13 (Research & Development), pp. 50-53

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May 26, 2021

AR 638 Workgroup Launch Announcement

This letter serves as an update to the AR 638 permanent rulemaking schedule and announces the launch of the topical wildfire mitigation planning work groups led by Public Utility Commission of Oregon Staff (Staff).

Permanent Rulemaking Schedule Update

Attached is an update to the AR 638 schedule and timeline for the permanent rulemaking. This update reflects the following changes:

- Work groups launch in May—kick-off meeting dates below
- Quarterly updates to the Commission begin in July
- Expectation to wrap workgroup efforts by October 2021—this timeline will be dependent on the final scope and meeting schedule identified with work group participants, but aware of the goal to begin formal rulemaking in Q1 2022.

Workgroup Launch

As described on pages 2-5 of Staff's Scope and Schedule Announcement, Staff proposes to structure discussion about permanent rules around topical work groups. Work groups will meet regularly to:

1. Develop a detailed issues list within each topic
2. For each issue, the work group will discuss:
    - Best practices for wildfire mitigation planning, activities, and investments;
    - Expectations for inclusion in utility plans – including near-term expectations and long-term vision; and
    - Metrics to track performance, ongoing improvement, and progress toward the long-term vision.
3. Document the outcome of discussion for all issues:
    - Areas of consensus
    - Parties' positions where this is not consensus
    - Areas where additional research or analysis are needed.

Work group participation information:

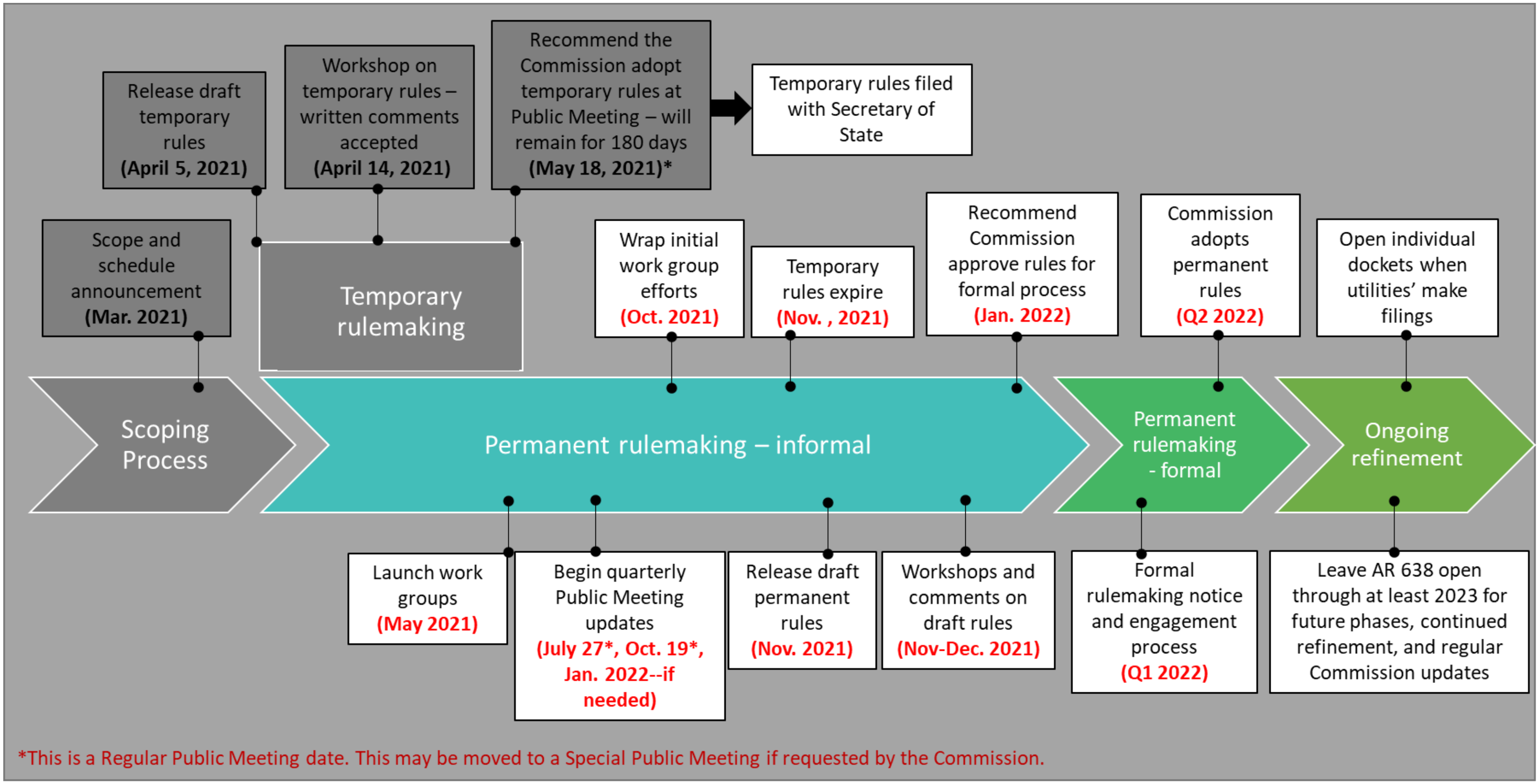
- Participation in work groups is open to any interested person. Each work group is assigned a Staff Contact. Please call or email the listed contact to join a work group. The Staff Contact will manage a participant list and communicate directly with work group members. Work group meeting schedules, notes, and other resources will be posted to the AR 638 docket and OPUC Wildfire Mitigation Webpage, as well.
- The date and time for kick-off meetings of each work group is provided in the table below.
- An agenda for each work group kick-off meeting will be sent directly to participants, posted to the AR 638 docket and noticed to the AR 638 service list, and posted to the OPUC Wildfire Mitigation Webpage.
- At the kick-off meeting, the work group will discuss meeting frequency and get feedback on structuring the work group.

Oregon Public Utility Commission

Work Group Launch Schedule			
Topic	**Proposed Scope** *To be refined with work group members*	**Staff lead** *Contact to join work group*	**Kick-off meeting date/time**
Wildfire Risk Analysis	Practices and methodology for identifying high fire consequence areas to inform mitigation plans	Curtis Dlouhy Curtis.DLOUHY@puc.oregon.gov 503-510-3350	June 14, 2021 2:00p – 4:00p (Pacific)
Public Safety Power Shut-off (PSPS)	Protocols, criteria, and communication/ coordination practices for deenergizing or sectionalizing circuits ***Please note: discussion of support for communities and vulnerable populations will occur in the Communication and Engagement group)*	Nadine Hanhan Nadine.HANHAN@puc.oregon.gov 503-931-0161	June 15, 2021 1:00p – 2:30p (Pacific)
Community Engagement	Emergency communications protocols, identification of vulnerable populations, utility obligations to support customers and communities (backup power, shelters, etc…)	Michelle Scala Michelle.M.SCALA@puc.oregon.gov 503-689-2608	June 15, 2021 2:45p – 4:15p (Pacific)
Vegetation Management	Schedules, standards, and enforcement	Mark Rettmann Mark.RETTMANN@puc.oregon.gov 503-881-6739	June 29,2021 1:00p – 2:30p (Pacific)
System Hardening and Operations	Identifying and prioritizing system hardening investments, operational practices, inspection practices, and other utility risk mitigation actions	Yassir Rashid Yassir.RASHID@puc.oregon.gov 503-949-5870	June 29,2021 2:45p – 4:30p (Pacific)
Cost Analysis	Approach to evaluating investment options e.g., cost recovery, performance metrics	TBD – will launch after scoping utility investments and operations to determine appropriate venue to discuss for cost-benefit analysis	

If you have questions about the process or content of this rulemaking, contact: Lori Koho, Administrator Safety, Reliability, & Security Division, 503-576-9789, lori.koho@puc.oregon.gov.

AR 638 – REVISED Risk-based Wildfire Protection Plans and Planned Activities Rulemaking Schedule



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August 19, 2021

AR – 638

Staff's Proposed Revised Scope

Over the past month, Staff has been reviewing and critiquing the original scoping document in light of the number of projects assigned to the Commission during the 2021 Legislative session.

Like many of you, we have limited resources and our goal is to have effective rules that will maintain relevance for several years but with recognition that they will be updated as we learn more.

Staff's proposed scope and schedule for developing Phase 2 rules are attached.

We look forward to your input at the upcoming August 23, 2021 workshop or through written comments.

Workshop Agenda

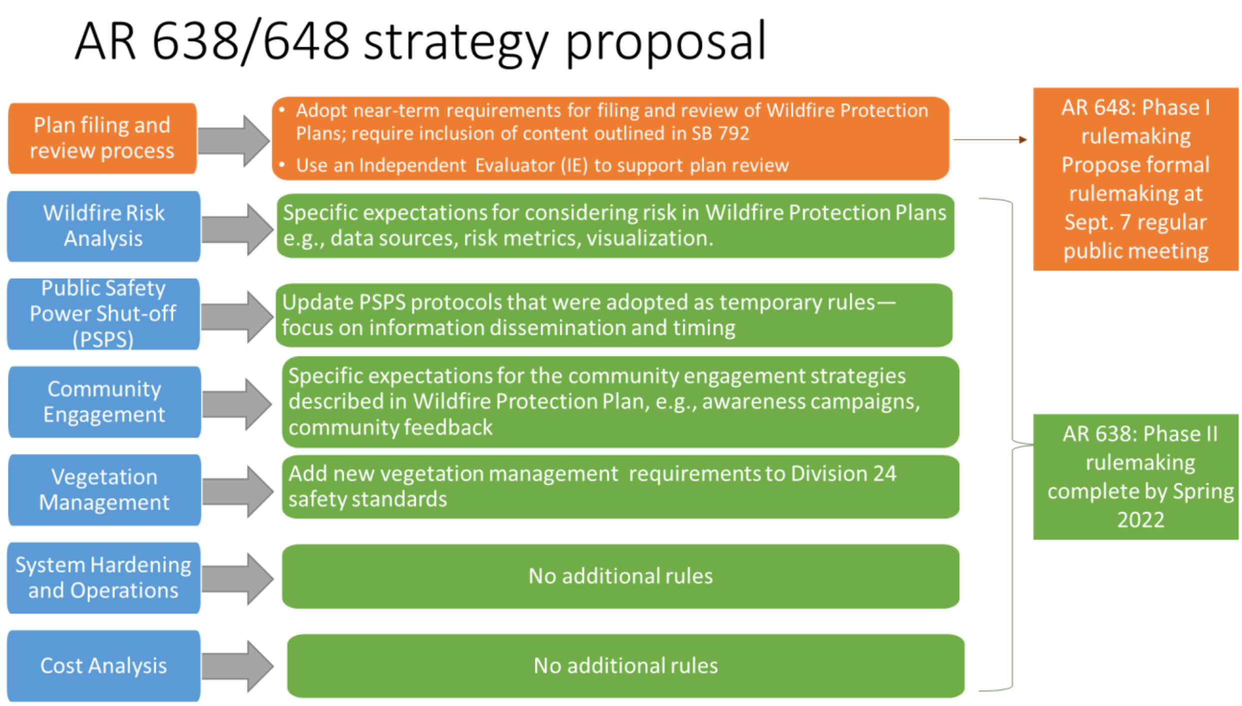
Welcome	5 minutes
Rulemaking strategy overview and phasing discussion	10 minutes
Phase II schedule review	5 minutes
Phase II scope review	1.5 hours total
Risk analysis	*10 minutes*
PSPS Protocols	*30 minutes*
Community Engagement	*30 minutes*
Vegetation Management and System Hardening	*20 minutes*
Additional question, comments, scoping issues	10 minutes

If you have questions about the workshop or rulemaking, please contact:

Lori Koho
Administrator Safety, Reliability, & Security Division
503-576-9789
lori.koho@puc.oregon.gov

AR 638 – Phase II Permanent rulemaking scope
DRAFT

This document describes Staff's revised scope for Phase II of the wildfire mitigation rulemaking. For ease of understanding major modifications, the revised scope is organized by the existing work group topic areas in the previous AR 638 scope.



Risk analysis

Adding to the Phase I rules to articulate specific expectations for considering risk in Wildfire Protection Plans.

Specific issues:

- Direction to use the most up-to-date data practicable from trusted sources
- Direction to use certain types of data (e.g., meteorological, topographical)
- Specify some sources or options for sources:
    - Meteorological data from NOAA
    - Must use at least one of these sources of topographical wildfire risk data:
        - ODF Wildfire Risk Explorer
        - BLM GIS models,
        - USFS Quantitative Wildfire Risk Assessment
        - Specific third party studies commissioned by the utility
- Direction to utilize certain methods
    - Requirement to confer with other state agencies in developing
    - Requirement to develop and describe metrics used to measure/describe risk across system

        - Includes a definition of high fire risk consequence areas and extreme fire risk consequence areas
    - Requirement to evaluate risk to utility service area/communities and utility equipment (including but not limited to)
    - Format is a map
- Requirements for detail presented in plan
    - Describe analytical methods
        - Include description of whether/how ODF, BLM, USFS data was used
    - Describe utility data
    - Describe how risk analysis is used for various things e.g., investment decisions, operational decisions, PSPS

PSPS

Creating a new permanent division for PSPS protocols that builds off of temporary rules as necessary with a focus on information dissemination and timing. Note: Phase I rules include procedural requirement to discuss PSPS plans in Wildfire Protection Plans—no proposed additions or changes to that in Phase II.

Specific issues:

- Requirements for preparation
    - Preparation activities with local public safety partners e.g., table top exercises
    - Contact information sharing with public safety partners and critical facilities
    - Data sharing e.g. data points, data type and format, conditions for calling a PSPS
        - Who gets what info in what format in preparation for PSPS season?
- Requirements when a PSPS is anticipated to occur
    - Notifications – shift focus to notifying public safety partners and critical facilities who will notify customers/community through existing technologies and systems
        - Prioritization, timelines
        - Content of notifications
        - Methods to reach different populations
            - Public safety partners (incl. OPUC)
            - Critical facilities
            - Customers – focus on inbound as minimum requirement (web, phone), but could include optional direct outbound outreach to vulnerable (medical, self-identified)
                - Any other utility requirements like press release, social media
            - Supporting public safety partners' efforts to identify vulnerable customers to the extent possible/legal
    - Data sharing
        - Requirements for freshness/granularity/format for sharing data when PSPS is anticipated e.g., require a real-time portal?
    - Coordination
        - Requirements for placing points of contact in response centers
- Reporting/follow-up info
    - Any changes we may need to the after event report
    - Any changes needed to end of season report

Community Engagement
Adding more detailed expectations to Phase I procedural requirement to include a community outreach and engagement strategy in Wildfire Protection Plans.

Specific issues
- Education and awareness strategy –Procedural requirement to include an education and awareness plan that is developed in coordination with public safety partners, informed by local needs and best practices. Plan must include:
  - Actions in preparation for season
    - Include PSPS education campaign
  - Actions during season
  - Actions after season
  - Specifics to ensure efficiency and efficacy e.g., multiple languages, multiple channels, use of description of metrics to ensure effectively reaching populations
- Wildfire Protection Plan engagement strategy – procedural requirement for describing the process that was used to engage community in development of risk mitigation plan (investment decisions/cost analysis framework, things that will be happening in community, where to find educational resources)
- Coordination requirements for utilities to work with local and state emergency planers and emergency responders for PSPS and in general for wildfire events

Vegetation Management
Adding new vegetation management requirements to the Division 24 safety standards. Note: Phase I rules include procedural requirement to include vegetation management strategy in the Wildfire Protection Plans—no changes proposed additions or changes to that in Phase II.

Specific issues:
- Requirement to conduct joint inspections with all attachers on a utility pole.
- Requirements for inspection frequency and methods for facilities in high fire consequence areas and all transmission facilities over 50 kV
- Additional considerations when establishing trim cycles (weather, wind, risk analysis, history, etc.)
- Reduction in time allowed to defer corrections of violations of Commission rules

System hardening
Phase I rules require utilities to describe how they are addressing system hardening using best industry practices in Wildfire Protection Plans.

Not proposing more than existing procedural requirement to describe utility strategy.

Cost analysis
Phase I rules require utilities to consider costs and benefits of strategies in Wildfire Protection Plans and to discuss those considerations as part of their plans.

Not proposing any changes to existing procedural requirement to include a cost-benefit analysis.

Date: January 26, 2022

TO:
JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST, 1WTC-0702
PORTLAND OR 97204
Jacquelyn.ferchland@pgn.com pge.opuc.filings@pgn.com;

FROM: Curtis Dlouhy
Senior Economist
Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 394 - PGE
Fourth Set Data Request filed January 19, 2022

PGE Data Request No 04:

4. Refer to Staff/2400/Dlouhy, page 5, lines 2-3. Please list all rate cases or other proceedings, other than UE 374, that group Wildfire Mitigation with Vegetation Management.

OPUC Response No 04:

4. As I note in Staff/2400, Staff believes that Wildfire Mitigation and Vegetation Management are inherently intertwined. I point out in my testimony that these two separate areas are addressed together in UE 374 when PacifiCorp's WMVM Cost Recovery mechanism was approved in Order No. 20-473. This was put into rates in ADV 1285. Additionally, the AR 638 rulemaking on Wildfire Protection Plans contained an entire workgroup devoted to Vegetation Management.

Date: January 26, 2022

TO:
JAKI FERCHLAND
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121 SW SALMON ST, 1WTC-0702
PORTLAND OR 97204
Jacquelyn.ferchland@pgn.com pge.opuc.filings@pgn.com;

FROM: Curtis Dlouhy
Senior Economist
Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 394 - PGE
Fourth Set Data Request filed January 19, 2022

PGE Data Request No 07:

7. Refer to Staff/2400/Dlouhy, page 7, lines 1-2. Please provide all supporting analyses and documentation, including any ORS or OAR, that a "vegetation management violation is a source of potential future ignition." If no such analyses or documentation are available, please describe in detail Staff's factual support for this statement.

OPUC Response No 07:

7. Staff notes that ORS 860-300-0002(h) requires the "[d]escription of the procedures, standards, and time frames that the Public Utility will use to carry out vegetation management in areas the Public Utility identified as heightened risk of wildfire." Further, it is common knowledge that contact between a tree and a powerline can create sparks that can turn into larger fires. While Staff does not believe that this needs further explanation, I refer you to this document put out by CalFire, this page about the city of Pasadena's tree trimming practices, and this news article where Pacific Gas & Electric Co. told a federal judge that a tree started the Dixie fire.

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August 28, 2020

MARIA POPE
PRESIDENT & CEO
PORTLAND GENERAL ELECTRIC
121 SW SALMON STREET
PORTLAND, OR 97204

RE: OPUC Report No. E20-49R, Portland General Electric (PGE)-Vegetation

Enclosed is a copy of OPUC Safety Report No. E20-49R, which cites probable violations on your system of the National Electrical Safety Code (NESC) and Oregon Administrative Rule (OAR) 860-024-0016.

OPUC Safety Staff recently performed the annual review of PGE's vegetation management program. This review occurred primarily from July 27th to August 21st, in the communities and rural areas listed within the body of the report.

Staff's report identifies locations where contact between vegetation and a primary conductor has been observed. Additionally, Staff noted, it appears that minimum clearances established by OAR 860-024-0016, are not being maintained. Many trees, although not actively in contact with a conductor, had less than the minimum clearances prescribed by the Administrative Rule. Staff notes these as observations because direct measurement is not possible or feasible during the review.

Staff acknowledges the challenges of the Covid-19 pandemic in the electric utility environment. The economic impacts, statewide wildfire mitigation activities, Advanced Wildfire Risk Reduction (AWRR) efforts in Tier 2 and Tier 3 wildfire risk areas, and off Right of Way (ROW) tree removal efforts are recognized. As a result, note the extended timeframes for correction under the "In response to this report:" section below.

A historical graph of readily climbable trees and primary conductor vegetation contacts is attached for your reference. The long term graph data indicates the number of tree and energized primary conductor contacts are approaching all-time highs.

This report contains a **"Warning"** indicating a vegetation program that appears to have serious deficiencies that are potentially system wide. Vegetation program modification and improvement is recommended to ensure that end-of-cycle clearances do not violate the minimum clearance requirements stated in OAR 860-024-0016. Staff analysis and details are contained in the remarks section of the report.

Staff observed **719** locations where evidence existed of contact between vegetation and primary electrical conductors. The identified locations resulted in conservatively over **1068** primary conductor vegetation contacts.

A limited breakdown of the probable violations follows:

- Thirty-nine locations identified in Citation: A, are readily climbable trees noted as **hazardous conditions.** Eighteen of the thirty-nine readily climbable tree locations, involve two or more trees contacting primary conductors.

- Of the six hundred seventy-seven locations identified in Citation: B, one hundred and ninety-nine locations involve two or more trees contacting primary conductors.

- Two locations: Citations A: 30 and 31 involve filbert orchards and agriculture workers, working in or around trees contacting energized conductors. This issue has been previously identified in Staff reports E04-61, E07-29 and E18-34.

In response to this report:

1. On or before October 30, 2020, submit documentation confirming correction of the probable violations related to **readily climbable trees**, as well as those listed specifically as **hazardous conditions**.

2. On or before April 30, 2021 submit documentation confirming correction of the remaining probable violations cited in this report.

If a time extension is needed, submit a written request stating the reason(s) for the delay and the proposed schedule to complete the work. If government permits are causing a delay, include the date the permits were applied for and a permitting agency contact person and telephone number. If you disagree with any cited probable violation, please furnish Staff a letter within 30 days requesting an informal conference.

Each electric supply and telecommunication operator in Oregon, (defined in OAR 860-024-0001(5)), is responsible to construct, operate, and maintain its line facilities in compliance with the NESC. Refer to ORS 757.035 and OARs 860-024-0010 and 860-023-0005 for Oregon laws and rules regarding minimum OPUC safety standards. Particular focus should be given to NESC Rules 090,110 121, 214, 313, and OAR 860-024-0011, which address ongoing inspection and maintenance responsibilities.

Failure to comply with the OPUC safety regulations or NESC rules can result in Commission orders and/or civil penalties. Refer to ORS 757.990(1) for penalty amounts.

If you have any questions regarding this letter or report, please contact me at the number listed below, Leon Grumbo at (503) 378-4165 or Steve Sims at (503) 378-8711. Please reply to OPUC.NESCSafety@state.or.us for report updates, time extensions, or to close the report in the OPUC enforcement log.

Mark Rettmann
Electric Safety Program Manager
Utility Safety & Reliability Section
(503) 378-5362
mark.rettmann@state.or.us
OPUC.NESCSafety@state.or.us

Attachments: Violation Report
Historical Vegetation Graph

Oregon

Kate Brown, Governor

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Administrative Services
503-373-7394

July 15, 2021

MARIA POPE
PRESIDENT & CEO
PORTLAND GENERAL ELECTRIC
121 SW SALMON STREET
PORTLAND, OR 97204

RE: OPUC Report No. E21-53R, Portland General Electric (PGE)-Vegetation

Enclosed is a copy of OPUC Safety Report No. E21-53, which cites probable violations of the National Electrical Safety Code (NESC) and Oregon Administrative Rule 860-024-0016.

OPUC Staff recently performed the annual review of PGE's vegetation management program. This occurred primarily from June 14 to July 9, 2021, in the communities and rural areas listed within the body of the report.

Staff's report identifies locations where contact between vegetation and energized high voltage conductors have been identified. Many trees, although not actively in contact with a conductor, had less than the minimum clearances prescribed by the Administrative Rule. Staff notes these as observations because direct measurement is not possible or feasible during the review.

This report contains a **"Warning"** notice, indicating a vegetation management program that continues to have system wide deficiencies. Vegetation program modifications and improvement are recommended to ensure end-of-cycle clearances do not violate the minimum clearance requirements outlined in OAR 860-024-0016. Safety Staff is optimistic regarding the trim cycle modifications PGE has proposed and adopted which should continue to improve the vegetation management program.

Staff acknowledges the impacts of the post Covid-19 pandemic in the electric utility and vegetation management programs. Safety Staff recognizes PGE's commitment to continuous improvement, attempting to overcome impacts of recent fires, ice storms, statewide wildfire mitigation activities, Advanced Wildfire Risk Reduction (AWRR) efforts, and off Right of Way (ROW) tree removals.

A historical graph of readily climbable trees and primary conductor vegetation contacts is attached for your reference. The long-term graph data indicates the number of tree and energized primary conductor contacts for the 2021 audit appear to be improving. However, the instances of "cycle buster" and end of cycle energized conductor tree contacts remain too high for the current wildfire environment. Maintenance of tree-to-conductor clearances, in general, are not adequate to meet the Oregon Administrative Rule throughout the duration of the trim cycle.

Executive Summary

Staff observed **533** locations where evidence existed of contact between vegetation and primary electrical conductors. The identified locations resulted in conservatively over **685** primary conductor vegetation contacts.

Staff analysis and details are contained in the remarks section of the report.

A breakdown of the highest risk probable violations follows:

- Twenty-eight locations are readily climbable trees noted as **hazardous conditions** in Citation: A.

- Eight of the twenty-eight readily climbable tree locations noted above, involve two or more trees contacting primary conductors.

- Of the five hundred and five locations identified in Citation: B, ninety-five locations involve two or more trees contacting primary conductors.

- Three locations: Citations A.1, A.18 and A.22 involve orchards and agriculture workers, working in or around trees contacting energized conductors. This issue has been previously identified in Staff reports E04-61, E07-29, E18-34 and E20-49.

In response to this report:

1. On or before August 20, 2021, submit documentation confirming correction of the probable violations related to **readily climbable trees**, as well as those listed specifically as **hazardous conditions**.

2. On or before January 17, 2022 submit documentation confirming correction of the remaining probable violations cited in this report.

If a time extension is needed, submit a written request stating the reason(s) for the delay and the proposed schedule to complete the work. If government permits are causing a delay, include the date the permits were applied for and a permitting agency contact person and telephone number. If you disagree with any cited probable violation, please furnish Staff a letter within 30 days requesting an informal conference.

Each electric supply and telecommunication operator in Oregon, (defined in OAR 860-024-0001(5)), is responsible to construct, operate, and maintain its line facilities in compliance with the NESC. Refer to ORS 757.035 and OARs 860-024-0010 and 860-023-0005 for Oregon laws and rules regarding minimum OPUC safety standards. Particular focus should be given to NESC Rules 090,110 121, 214, 313, and OAR 860-024-0011, which address ongoing inspection and maintenance responsibilities.

Failure to comply with the OPUC safety regulations or NESC rules can result in Commission orders and/or civil penalties. Refer to ORS 757.990(1) for penalty amounts.

If you have any questions regarding this letter or report, please contact me at the number listed below, Leon Grumbo (503) 378-4165 or Steve Sims (503) 378-8711. Please reply to OPUC.NESCSafety@puc.oregon.gov to report updates, request time extensions, or close the report in the OPUC enforcement log.

Mark Rettmann
Electric Safety Program Manager
Utility Safety Reliability & Security Division
Oregon Public Utility Commission
(503) 881-6739
(Note new email address)
mark.rettmann@puc.oregon.gov
OPUC.NESCSafety@puc.oregon.gov

Attachments: Violation Report
Historical Vegetation Graph

Exhibit 2808 – Comparison of PGE's Service Area and PacifiCorp's Oregon Service Area

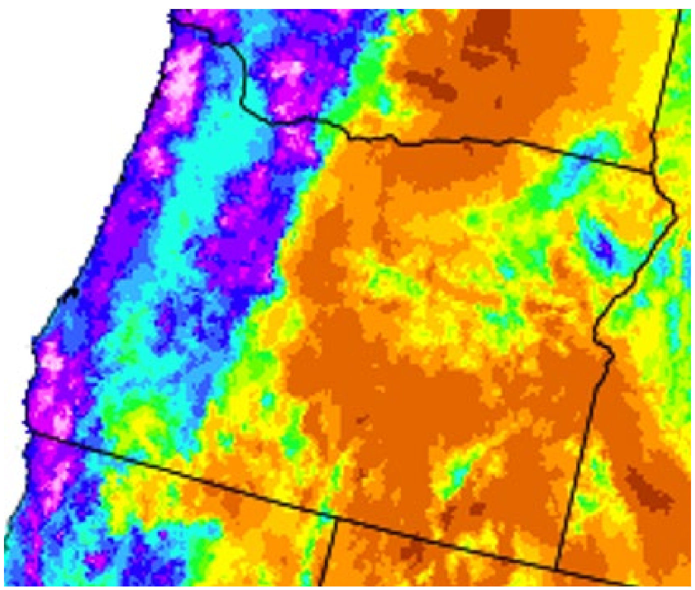
PacifiCorp's Oregon Service Area

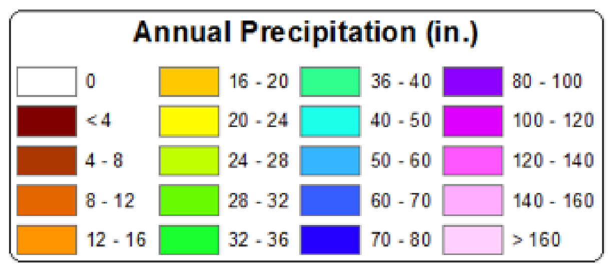
Source: https://www.pacificpower.net/community/service-area.html

PGE's Service Area

Source: https://portlandgeneral.com/about/info/service-area

Average Annual Precipitation Over 1991-2020





Source: https://prism.oregonstate.edu/normals/

Date: January 26, 2022

TO:
JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST, 1WTC-0702
PORTLAND OR 97204
Jacquelyn.ferchland@pgn.com pge.opuc.filings@pgn.com;

FROM: Curtis Dlouhy
Senior Economist
Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 394 - PGE
Fourth Set Data Request filed January 19, 2022

PGE Data Request No 13:

13. Refer to Staff/2400/Dlouhy, page 11, lines 17-19. Staff states that "…should the Company indeed spend more than their budgeted amount for WMVM expenses proposed in this rate case, it will be able to fully recover the first $3 million incremental costs subject to a prudence review." Given that the $3 million holdback is a part of PGE's budgeted amount for WMVM, and not an "incremental cost" and that it has already been reviewed and deemedprudent in this rate case, please clarify whether recovery of this money would be subject to the performance-based rate mechanism and earnings test.

OPUC Response No 13:

13. The $3 million holdback would be subject to the performance-based rate mechanism and earnings test.

Date: January 26, 2022

TO:
JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST, 1WTC-0702
PORTLAND OR 97204
Jacquelyn.ferchland@pgn.com pge.opuc.filings@pgn.com;

FROM: Matt Muldoon
Manager
Rates, Finance and Audit Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 394 - PGE
Fourth Set Data Request filed January 19, 2022

PGE Data Request No 16:

16. Refer to Staff/2200/Muldoon, pages 5-6, lines 22-2. Please explain how Dr. Dlouhy's proposed PBR mechanism is a "holistic approach" to ensure the company is "minimizing the chance of a fire" when it only considers one metric (that is, vegetation management violations).

OPUC Response No 16:

16. The reference to "holistic" was meant to describe the fact the mechanism proposed by Mr. Dlouhy provides an incentive to be proactive in vegetation management and a deterrent to not being proactive in vegetation management.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Deferrals

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Alex Tooman, Ph.D.
Jaki Ferchland

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Alex Tooman. I am a Senior Regulatory Consultant for PGE. My qualifications were previously provided in PGE Exhibit 200.

My name is Jaki Ferchland. I am the Manager of Revenue Requirement in Regulatory Affairs at PGE. My qualifications were previously provided in PGE Exhibit 900.

Q. Ms. Ferchland, do you adopt Mr. Batzler's prior testimony in this matter as your own?

A. Yes. I adopt Mr. Batzler's Reply Testimony in this matter (PGE Exhibit 2300, Tooman – Batzler) filed on December 8, 2021.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony provided by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Oregon Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC) (collectively, the Parties) with respect to deferrals.

Q. What specific issues do you address in your testimony and how is it organized?

A. We address the following issues:

- Section II – CUB's proposal regarding deferrals and return on equity (ROE);
- Section III – The Parties' proposals to amortize the Boardman deferral (Docket UM 2119), the wildfire emergency deferral (Docket UM 2115), and the ice storm emergency deferral (Docket UM 2156);
- Section IV – AWEC's proposal regarding PGE's deferral for third-party transmission revenue; and
- Section V – Summary and Conclusions.

II. Deferrals and Return on Equity

Q. Please summarize CUB's argument regarding deferrals and ROE.

A. CUB argues that "[s]ince deferrals and single-issue ratemaking mechanisms reduce shareholder cost recovery risk, CUB proposed to adjust overall return on equity (ROE) in future proceedings. At the time of a future general rate case (GRC), for every 1% of revenue requirement that is held within deferrals, a utility's return on equity (ROE) would be adjusted downwards by 5 basis points."[1]

Q. On what basis does CUB make this argument?

A. CUB argues that "it is well established that deferrals and automatic adjustment clauses avoid shareholder risk associated with using GRCs to forecast costs, and therefore reduce the utility shareholder's overall risk profile. Since these mechanisms do not rely on a forecast, they enable dollar for dollar recovery of utility expenditures. ROE is designed to compensate utility shareholders for the cost recovery risk they are incurring in the regulatory process. Therefore, common sense would suggest that there is a threshold number of single-issue ratemaking mechanisms that would require a reduction in ROE. The more single-issue ratemaking mechanisms, the greater the cost recovery certainty. The greater the cost recovery certainty, the less risk that shareholders incur."[2]

Q. Do you agree with CUB's proposal and argument in support of it?

A. No. CUB's proposal is fatally flawed for several reasons. First, there is no consideration of the types of deferrals and how they might or might not apply to CUB's proposal. Second, there is no consideration as to how Commission policy already addresses the referenced risk.

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[1] CUB/400, Jenks-Gehrke/2.
[2] CUB/400, Jenks-Gehrke/2

Third, the proposal has no analytical support and is vague. We address each of these aspects below.

A. Types of Deferrals

Q. Please explain how CUB has given no consideration of the types of deferrals PGE has in place and how they might or might not apply to CUB's proposal.

A. In PGE Exhibit 2300, pages 4-5, we provided testimony that categorized the four major types of deferrals that PGE currently has active.[3] We discuss them here in more detail to demonstrate how they do not belong in base rates or pertain to CUB's proposal.

Extraordinary and/or limited duration deferrals (rows 3-12 of Staff/1103)

These deferrals relate to items such as the declared emergencies (i.e., COVID, Wildfires, and Ice Storm), the OPUC regulatory fee (OPUC fee), and Oregon Corporate Activity Tax (OCAT). Because these are of limited duration and/or extraordinary, they do not belong in base rates which are intended to reflect regular, on-going costs. For example, the OPUC fee and OCAT are deferred because PGE had a statutory or Commission requirement to increase these costs, but those requirements came in between GRCs. The point of these deferrals is to provide cost recovery for mandatory costs until they can be incorporated in base rates.[4] The declared emergencies are particularly extraordinary so that they cannot possibly be forecast as part of base rates.

Pilots (rows 13-19 of Staff/1103)

These deferrals relate to evolving projects such as demand response (part of PGE's Multi-Year Plan for Flexible Load as discussed in Docket UM 2141), transportation electrification,

[3] For the complete list, see Staff Exhibit 1103.
[4] Both the OPUC fee, as required by Commission Order 21-066, and the OCAT are included in PGE's UE 394 revenue requirement for base rates.

and energy storage. By definition, these deferrals are fraught with uncertainty in activity, variability in costs from year to year, and possible unknown duration. PGE pursues them to test the potential for fully scalable programs that will benefit all customers if the pilots prove successful or provide enough learnings to develop an alternative program. Eventually, the programs become mature and stable such that they are appropriate to include in base rates. While in the pilot stage, however, they do not reflect regular costs with a basis for accurate forecasting.

Balancing accounts (rows 20-23 of Staff/1103)

These deferrals address the need for certain statutory or Commission-approved mechanisms to separately track in-flows of revenues with out-flows of costs. The Multnomah County Tax, Metro Tax, and energy efficiency customer service balancing accounts are all necessary with separate tariffs because they only apply to certain customers. PGE's major maintenance accrual has its costs and balances already included in base rates but, as in all these cases, PGE was required to file deferrals to support the existing mechanisms. Curiously, when PGE attempted to consolidate them into a single deferral filing for administrative efficiency, Staff responded by requesting "the Commission direct PGE to file separate deferral applications for each different *type* of balancing account" (emphasis in original).[5]

Irregular deferrals (rows 24-32 of Staff/1103)

These deferrals are all a function of long-term Commission-approved mechanisms. More importantly, they are irregular, which means that the amount to defer can vary significantly from year to year so that one year's deferred costs or revenues are not representative of any other years' deferred costs or revenues. For example, PGE's power cost adjustment

[5] Commission Order 19-020, Appendix A, page 3.

mechanism and decoupling deferrals can reflect collections or refunds in any given year. The qualifying facilities deferral is structured to flow through PGE's annual power cost update filing, which is a tariff schedule included as part of base rates. The research and development tax credit deferral has multiple vintages of credits as they pertain to estimated amounts that will take years for each to flow through the income tax filing and Internal Revenue Service review process. In all these instances, there is no basis for creating a forecast or including the costs or revenues in base rates.

In summary, each of the above categories represent costs or revenues that are appropriately deferred or require balancing accounts with associated deferrals. Consequently, they do not fall under CUB's blanket generalization of deferrals that reduce risk, except as noted next.

B. Deferrals and Risk

Q. Please explain how CUB is ignoring the ways Commission policy already addresses the referenced risk.

A. In Docket UM 1147, the Commission conducted an investigation into deferrals. The basis for this was the concern that deferred accounting was being employed too easily by utilities, and if so, how this should be addressed. Staff proposed a matrix of risks to address certain kinds of costs, and although the Commission did not formally adopt the matrix, to allow themselves discretion and flexibility, they nevertheless found that "the matrix is very illustrative of our policy in this matter." As such, the matrix is typically referenced with deferrals that fit into the matrix's elements. An example of this application is Docket UM 1817, where PGE unsuccessfully sought deferred accounting for its 2017 excess Level III restoration costs.

Q. How is the matrix discussed or applied in such instances?

A. Parties to such proceedings invariably argue whether the risk is stochastic or scenario. This is important because "[t]he type of event—modeled in rates or not, foreseeable or not—will affect the amount of harm that must be shown by the utility. If the event was modeled or foreseen, without extenuating circumstances, the magnitude of harm must be substantial to warrant the Commission's exercise of discretion in opening a deferred account. If the event was neither modeled nor foreseen, or if extenuating circumstances were not foreseen, then the magnitude of harm that would justify deferral likely would be lower."[6]

Q. Has the matrix been referenced or applied in any of PGE's deferrals discussed in Part A or listed in Staff Exhibit 1103?

A. Not as of this writing. However, the deferrals for declared emergencies clearly represent scenario risk and the matrix can be applied during either the deferral authorization stage or amortization stage. As we discuss in Section III below, Staff Exhibit 2600 curiously recommends that a different type of threshold be applied to these deferrals based on a Commission decision from 12 years prior to the UM 1147 order. We also note that the Customer Touchpoints (Docket UM 1948) and Wildfire Mitigation (Docket UM 2019) deferrals would likely be argued to be stochastic risk by Parties although these have never been processed for a Commission decision (given their increasing age and growing unlikelihood for approval, this appears to be another way for Staff to apply a threshold).

Q. Besides these five deferrals, has the matrix been applied to any of the remaining 25 deferrals listed on Staff Exhibit 1103?

[6] Commission Order 05-1070, page 7.

A. No. All but one of the remaining 25 deferrals are approved and all but one or two are in the amortization phase.[7] During all these proceedings, there has been no reference to the matrix.

Q. What does this mean in relation to CUB's argument for an adjustment to ROE?

A. It means that where the matrix is referenced, the applicable business risk is already considered with respect to the amount to be deferred or amortized. Where the matrix is not referenced, there is the recognition that business risk is not applicable and not imposed. In short, CUB's concern about risk is already addressed by standing Commission policy and CUB's attempt to apply an additional reduction to ROE is unwarranted.

Q. CUB claims that automatic adjustment clauses (AACs) "reduce risk and stabilize earnings and, therefore, should be reflected in the ROE."[8] Do AACs create an exception to your previous statements?

A. No. AACs are typically applied to deferrals that will likely run for several years and have not been subject to the matrix. The advantage of these deferrals for customers is that they begin in the amortization phase, which has the lower modified blended treasury rate of interest. In addition, one of PGE's primary AACs is its Power Cost Adjustment Mechanism. As stated in PGE Exhibit 900, rating agencies and analysts have specifically noted that this AAC adds to PGE's risk and earnings volatility because of its asymmetry and cost recovery limitations. The Commission has not, however, adjusted ROE upward based on this risk-producing AAC so there is no basis to decrease ROE based on CUB's unsubstantiated observations about risk-reducing AACs.

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[7] Docket UM 2184 is not yet approved. PGE filed it to defer costs associated with an independent evaluator and third-party consultants for a request for proposal (RFP). Because this has been typical treatment for prior RFPs, we believe that this will not be an exception to this testimony.
[8] CUB/400, Jenks-Gehrke/4.

Q. When the Oregon Legislature authorizes deferrals or single-issue ratemaking, is it often in the context of legislative mandates that increase the utility's overall risk?

A. Yes. An example is Oregon's renewable portfolio standard, enacted in SB 838 and SB 1547. This statute increases the utility's risk by requiring changes to the utility's generation portfolio but then mitigates this risk by mandating cost recovery through an AAC under ORS 469A.120(2). CUB's proposal is one-sided: focusing only on the risk-reducing aspects of such legislation (i.e., deferrals and AACs) without accounting for the risk-increasing aspects.

C. No Analytical Basis or Resulting Adjustment

Q. Please explain how CUB's proposal has no analytical support.

A. CUB proposes a quantitative solution (5 basis point reduction to ROE) to a quantitative issue (every 1% of revenue requirement that is held within deferrals) but offers no analysis to support or explain why these are proper or correct parameters. Nor does CUB's proposal address the fact that the Commission's framework already accounts for business risk as applicable to individual deferrals. With no analytical support and by doubling-counting business risk reduction, CUB's proposal is completely arbitrary.

Q. Please explain how CUB's proposal is vague and open to different interpretations.

A. CUB's proposal specifically relates to "1% of revenue requirement that is held within deferrals." It is unclear whether CUB is referring to deferral balances or amounts in amortization. Proposals to the Commission, however, should be straight-forward and not subject to interpretation. Because PGE's largest deferrals are currently not in amortization, and might not be at any time that a GRC is being decided, we <u>interpret</u> CUB's proposal to refer to total deferral balances.

Q. How would CUB's proposal be applied if based on PGE's deferral balances?

A. First, we would remove the deferrals associated with declared emergencies. Those not only represent scenario risk as discussed in Part A, but they are also effectively recognized as special cases by the issuance of Commission Order No. 21-259 in Docket UM 2181—which makes no mention of any associated ROE adjustment. Then we should also remove the Customer Touchpoints and Wildfire Mitigation deferrals as they are increasingly unlikely to have any approval. After doing so, we see that the balances in Staff Exhibit 1103 total only \$0.145 million including interest, or a credit of \$1.600 million excluding interest. These would produce either no adjustment to ROE (based on including interest) or a minute increase to ROE (based on excluding interest) if CUB's proposal is applied symmetrically (*i.e.*, to permit increases or decreases to ROE). This calculation, however, is only for demonstration purposes since CUB's proposal has no merit as demonstrated in Parts A through B, above.

III. Boardman and Emergency Deferrals

Q. Please summarize Parties' proposals regarding the Boardman deferral, the wildfire emergency deferral, and the ice storm emergency deferral.

A. Parties raise a number of issues regarding the three deferrals but their primary proposals are as follows:

- CUB recommends that the Commission order the amortization of the Boardman deferral over three years for refund to customers. With respect to the emergency deferrals, CUB asks PGE to support legislation that would allow PGE to securitize the costs.[9]
- AWEC recommends the Commission: 1) approve $15.0 million in annual amortization related to the two emergency deferrals in this proceeding, subject to refund; and 2) initiate a consolidated docket to review and establish final amortization schedules for all three of the outstanding deferrals. AWEC, however, is willing to delay amortization of the Boardman deferral until it can be evaluated in the consolidated docket.
- Staff recommends that the Commission: 1) approve AWEC's and CUB's request to defer Boardman costs currently in rates; and 2) approve specific sharing percentages and earnings test benchmarks for the emergency deferrals.

Q. Please respond to CUB's request that PGE support new legislation.

A. While PGE is generally supportive of the concept of securitization and sees the benefits to customers, new legislation will likely not be in place in time for this GRC.

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[9] CUB/500, Gehrke/5-6.

Q. What other issues do the Parties raise with respect to these three deferrals?

A. The primary issue that Parties raise relates to lag, which is particularly significant because it underlies a number of their other arguments. They also express concerns about the legality and fairness of PGE recovering Boardman costs in rates after the plant has closed. In addition, Parties raise issues regarding incentives, and CUB questions whether PGE has been inconsistent with its recognition of the significance of the Boardman closure. Finally, Staff and AWEC indicate that certain costs need to be removed from the emergency deferrals as they are inapplicable for recovery.

Q. What is your overall response to the Parties' proposals and the issues raised?

A. We disagree with the Parties' positions. In summary, we will show that the Parties' testimony is undermined by inconsistencies and contradictions and should not be used as the basis for a Commission decision.

A. Legality and Fairness

Q. What do Parties claim regarding the legality of PGE recovering Boardman costs in rates after the plant has closed?

A. CUB and Staff cite ORS 757.335 as the appropriate standard for determining the legality of including Boardman in rates after it has ceased operations.

Q. How do you respond?

A. While we are not lawyers, we understand that the issue the Commission must resolve is whether the rates are fair and reasonable during the lag period between the closure of the plant and the date new rates are set in this case. Because this is a legal issue, PGE will address this issue further in Briefs.

Q. What do Parties claim regarding the fairness of PGE recovering Boardman costs in rates after the plant has closed?

A. CUB primarily raises the issue of fairness by noting that:

- "Allowing a utility to earn a profit from customers on a coal plant that is closed and has been fully paid for, particularly when the utility is able to use an automatic adjustment clause to recover the costs associated with the clean energy replacement, is not fair"[10]; and
- "However, the Company has eliminated regulatory lag from major generating investments but wants to subject those facilities to regulatory lag after they no longer provide service. This is patently unfair. The fact that there is regulatory lag for line transformers and other portions of the distribution system is not a significant reason to have generation rate base treated unfairly."[11]

Q. How do you respond?

A. CUB's comments are not compelling when considering the larger context of PGE's prudent and reasonable costs and what portion of these costs is actually included in rates. CUB's second comment in particular references regulatory lag, which is at the heart of much of Parties' arguments. Consequently, we do not believe it is meaningful to address the qualitative and subjective aspects of a term such as "fairness", but instead will focus on the quantitative aspects of lag and how it is being applied or misapplied by the Parties.

B. Regulatory Lag

Q. How do you define "regulatory lag"?

[10] CUB/400, Jenks-Gehrke/14
[11] CUB/400, Jenks-Gehrke/20

A. Rates are normally set on a prospective basis only. Regulatory lag refers to the costs a utility cannot recover in rates between rate cases and within a rate proceeding when rates are frozen pending approval of a new rates. Under traditional ratemaking, a utility carries both the risk (regulatory lag) and the rewards ("negative lag") associated with "between rate case" occurrences.

Q. Please summarize the Parties' positions on regulatory lag.

A. Parties appear to believe that utilities should always experience a certain amount of lag. CUB's issue with fairness pertains to the fact that PGE's overall lag was reduced by "negative" lag (or cost savings) associated with the Boardman plant retirement in October 2020. CUB also emphasizes its concerns about lag by discussing specific types of costs that customers paid for in rates to effectuate the retirement of Boardman such as accelerated depreciation and retention and severance costs. CUB claims that these costs justify a deviation from normal ratemaking for Boardman, reducing rates immediately after the plant was closed, instead of waiting for the final order in this case to remove these costs from base rates.

Q. How do you respond?

A. The Parties' position that customers should be credited for "negative" lag related to a plant closure between rate cases is both unprecedented and unprincipled. The Commission has been clear that "under traditional ratemaking, a utility continues to recover a return of and return on plant balances included in rate base during its last rate case, even though the value of the assets has depreciated since then."[12] Parties do not address any objective measures for applying their proposed approach here or in future cases (e.g., how much and what kind of "negative" lag should utilities be allowed to take as an offset to regulatory lag). Nor do they

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[12] *In the Matter of Public Commission of Oregon, Investigation of the Scope of the Commission's Authority to Defer Capital Costs*, Docket UM 1909, Order No. 20-147 (April 30, 2020)

address how the Commission can consistently determine whether rates have been fair, just, and reasonable without such standards.

Q. How much lag has PGE been absorbing and over what period of time?

A. As noted in PGE Exhibit 2300, from the rate effective date of PGE's last GRC (Docket UE 335), through the effective date of rate base in the current GRC (April 30, 2022), PGE will have absorbed approximately $157.1 million in revenue requirement lag for plant-in-service that is not reflected in rates.[13] To be clear, this number includes the benefit of Boardman plant-related costs being recovered in rates.

Q. Do Parties accept this number?

A. No. They question three aspects of PGE's analysis. First, CUB and AWEC note that PGE did not recognize that there is also load-driven revenue growth that offsets that lag. Second, CUB states that "PGE is including 2019 and 2020, where the earning review should be limited to the deferral period which does not include 2019 and only includes a few months of 2020."[14] Third, AWEC states that "[r]egulatory lag is irrelevant to the Boardman Deferral. Only a minor portion of the Boardman Deferral represents capital. Further, the other capital projects that PGE alleges is being subject to regulatory lag is not being deferred. Going back in time to consider those capital additions outside of a rate case would therefore constitute retroactive ratemaking."[15]

Q. How do you respond to these objections?

A. PGE agrees that the $157.1 million is a gross number and that some revenue growth could reasonably be applied against it. The issue is that other costs have also increased significantly,

[13] From December 31, 2018 (rate base established for Docket UE 335) through April 30, 2022 (stipulated rate base in this GRC) PGE has implemented over $820 million in net plant in service that accounts for this lag.
[14] CUB/400, Jenks-Gehrke/20.
[15] AWEC/300, Mullins/7.

(e.g., wildfire mitigation, vegetation management, and the highest inflation in approximately 40 years) such that revenue growth is needed to cover a variety of increasing costs. Nevertheless, for the sake of completeness, PGE has analyzed the full amount of non-power-cost revenue growth over the referenced period and determined that it is approximately $58.8 million. If this entire amount is applied against the $157.1 million, PGE is still experiencing approximately $98.3 million of net lag. The $58.8 million of revenue growth, however, does not apply solely to plant-related lag.

Q. How is CUB's second objection misleading?

A. As noted above, the $157.1 million or $98.3 million relate to the period in between the rate effective dates of the prior and current GRC. This is when the lag would occur – where the capital costs are being incurred but not built into rates (i.e., January 1, 2019 through April 30, 2022). Instead, CUB argues that the period that matters is where the earnings review applies to the deferral period (i.e., late 2020 through April 30, 2022). This is misleading because PGE is not presenting this analysis for the sake of an earnings review. Instead, we are informing the Commission that in spite of the Boardman closure not being reflected in rates, PGE's rates are fair, just and reasonable, in part because PGE has and is experiencing considerable lag as we managed our costs in order to avoid filing a GRC until July 9, 2021.

Q. Do Parties question other aspects of PGE's lag?

A. Yes. In order to further dismiss PGE's lag, CUB argues that the $157.1 million or $98.3 million represents the wrong kind of lag by stating "[t]he fact that there is regulatory lag for line transformers and other portions of the distribution system is not a significant reason to have generation rate base treated unfairly."

Q. Is this a reasonable argument?

A. No. What CUB is effectively saying is that we should unbundle the earnings review for PGE's rates, such that a temporarily low Distribution ROE would not be allowed to offset a temporarily high Generation ROE, regardless of the overall utility ROE. This argument is unreasonable because it is saying that PGE is experiencing the <u>wrong kind</u> of lag. It also appears to contradict the Parties' long-standing position for applying a more holistic approach to rate making and instead selectively advocates for a more piecemeal approach. when it suits them.

Q. How do you respond to AWEC's claim about the lag from capital projects?

A. AWEC's claims are incorrect and irrational. First, over half of the Boardman revenue requirement is capital-related; not a "minor portion" as claimed by AWEC. Second, PGE deducted the non-plant portion of the Boardman revenue requirement from its analysis to specifically recognize that this lag applies to other costs. Finally, the fact that PGE's incremental capital since UE 335 is not being deferred is precisely why there is the $157.1 million of lag. Because PGE has not requested a deferral for that capital and will not otherwise recover it in rates, there is lag and <u>no</u> retroactive rate making.

Q. Please summarize your response to these issues regarding lag.

A. Parties are creating a Catch-22 for the utility if they first insist that some level of lag is necessary for rates to be fair, just and reasonable but then find every reason to dismiss that lag if it is shown to exist. We are being told there is not enough lag, or it is the wrong kind of lag, or it is lag during the wrong period, or that it somehow doesn't apply because of a non-existent deferral. These represent hopelessly vague and unrealistic regulatory hurdles which should not be the basis for Commission policy.

C. Earnings Reviews and Cost Sharing

Q. How does an earnings review relate to lag?

A. An earnings review reveals the extent that lag has impacted the utility's ROE. If the utility absorbs significant lag but also has significantly offsetting revenue growth or some other form of cost reduction (all else equal), the earnings review will indicate an ROE that is not negatively impacted. If the utility has significant lag but does not have offsetting revenue growth or some other form of cost reduction (all else equal), the earnings review will indicate an ROE that is negatively impacted. The resulting ROE provides the Commission with a quantitative method to evaluate the utility's need to collect deferred costs or refund over-collected revenue.

Q. How does PGE propose to apply the earnings review to the emergency deferrals?

A. All parties, including PGE, agree that ORS 757.259 prescribes an earnings review but is otherwise not specific as to how that is determined or applied. Absent clear guidance, PGE assumes that the default condition is the utility's most recently authorized ROE and how it compares to PGE's actual regulated ROE as determined in PGE's annual Results of Operations Report. Based on this earnings review standard, PGE would collect deferred costs up to the point that it's actual regulated ROE is equal to its authorized ROE or would refund deferred credits down to the point that it's actual regulated ROE is equal to its authorized ROE.

Q. Why does PGE assume this is the proper or default standard?

A. We do so for two reasons. First, we have three deferrals in recent history with prescribed earnings review parameters. In PGE's 2011 GRC (Docket UE 215), Parties stipulated to a deferral for four capital projects and agreed "to support use of PGE's authorized return on equity established by the Commission in this proceeding as the standard for measuring PGE's earnings."[16] In addition, PGE's environmental remediation deferral (Docket UM 1789) relies on "PGE's Return on Equity authorized by the Commission in PGE's most recent general rate case."[17] Finally, in NW Natural's environmental remediation deferral (Dockets UM 1635/1708) the Commission stated that "NW Natural will be allowed to amortize deferred amounts as necessary to bring its earnings up to its authorized ROE."[18]

Q. What is the second reason for assuming the proper or default standard for an earnings review is the utility's most recently authorized ROE

A. The second reason is that businesses prefer to have some measure of consistency regarding regulation so that predictable rather than arbitrary outcomes can help planning and forecasting. With respect to deferrals, a reasonably consistent standard would allow utilities to book accounting entries that reflect expected results in the year in which they apply. Authorized ROE provides a clearly-defined basis on which to make such entries. Although, we do not expect authorized ROE to be applied in all instances and under all conditions, it provides a reasonable and consistent basis for evaluation.

Q. Do Parties agree with PGE's assumption?

A. Staff does not agree and offers an alternative proposal. CUB does not specifically address this issue while AWEC observes that "[a]n earnings test, for instance, is already occurring through the revenue requirement calculation being evaluated by the parties in this docket"[19] and "in this case, where there are offsetting deferrals with a comparable impact, the earnings

[16] Commission Order 10-478, Appendix B, page 4.
[17] Commission Order 17-071, Appendix A, page 6.
[18] Commission Order 15-049, page 13.
[19] AWEC/300, Mullins/5.

test is less relevant, as the net impact of the deferred items did not have a significant impact on earnings."[20]

Q. What is Staff's alternative proposal?

A. Staff's proposal has two components. First, "Staff recommends the Commission adopt an earnings test benchmark of 100 basis points below PGE's authorized ROE. PGE would be allowed to amortize deferred costs only to the extent the amortization does not increase PGE's earnings above this benchmark. PGE would also not be able to amortize any portion of a credit that would cause PGE's earnings to go below this benchmark."[21] Because this applies to all three deferrals, it is asymmetric. For PGE, with a 9.5% authorized ROE, the earnings test benchmark would be 8.5% for all three deferrals.

Q. What is the second component of Staff's proposal?

A. "Staff recommends 90/10 sharing between ratepayers and PGE, with PGE absorbing ten percent of the prudently-incurred deferred costs. This sharing would be applied before application of the earnings test and accordingly, only 90 percent of the prudently incurred amounts that have been approved for deferral would subject to the earnings test."[22] Staff further states that the 90/10 sharing does not apply to the Boardman deferral.

Q. Why does Staff believe the 90/10 sharing should not apply to the Boardman deferral?

A. Staff states that "[u]nlike the recovery of costs in the Wildfire and Winter Storm Deferrals, allowing PGE to keep a percentage of the deferred amounts will not incent behavior that is beneficial for customers. In fact, allowing PGE to keep a portion of the amounts collected from customers for a plant that was not operational incents PGE to continue to charge

[20] AWEC/300, Mullins/5.
[21] Staff/2600, Moore-Dlouhy-Storm/15.
[22] Staff/2600, Moore-Dlouhy-Storm/16-17.

customers for as long as it can for the retired plant rather than seeking a rate change to eliminate recovery for Boardman from its revenue requirement."[23]

Q. Do you agree with this?

A. No. Recent evidence proves this assertion to be false. In this very proceeding, PGE has proposed that the Colstrip revenue requirement be separated from base rates and moved into a supplemental schedule. PGE is proposing this so that when Colstrip plant is no longer producing energy for PGE, we can terminate the Colstrip tariff and do the opposite of what Staff is suggesting.

Q. What would be the impact of Staff's proposal?

A. We cannot make this determination without a year-by-year determination of PGE's actual ROE but we can observe that, based on only the O&M amounts of the emergency deferrals as presented in PGE Exhibit 2401, the 10% share for PGE would be approximately $10.9 million. We also know that the 100 basis points earnings test benchmark that Staff proposes to apply would amount to approximately $39 million. This would place up to a $50 million annual penalty on PGE's recovery of the emergency deferrals that is not applied to the Boardman deferral. This penalty is not only asymmetric, it is also arbitrary and inappropriate.

Q. Is Staff's 100 basis-point proposal supported by Commission precedent?

A. No. Staff appears to rely on general statements from the Commission in an order that is almost three decades old.[24] However, Staff's proposal is not supported by the more recent Commission precedent discussed above that set the earnings review threshold at the utility's authorized ROE. Also, in Commission Order No. 05-1070 from Docket UM 1147, which was specifically called by the Commission as an investigation into deferrals, the Commission

[23] Staff/2600, Moore-Dlouhy-Storm/17-18.
[24] Staff/2600, Moore-Dlouhy-Storm/14.

addressed the matrix as discussed in Section II, Part B, above. Based on the application of the matrix: 1) the emergency deferrals would fall under scenario risk and the Boardman deferral would fall under stochastic risk; and 2) stochastic risk would have a much higher threshold than scenario risk. We are not advocating that these thresholds be applied to these deferrals but note that this asymmetry is the opposite of what Staff is advocating.

Q. Is Staff's 90/10 sharing proposal supported by Commission precedent?

A. No, the precedent Staff relies on is not analogous. While the Commission has previously adopted 90/10 sharing, it was in the context of plant outages. Staff's reliance on this order is inappropriate because the Commission adopted the sharing in that case as "an incentive to the utility to minimize the duration of, and costs associated with, future plant outages."[25] However, plant outages (stochastic risk) bear no relationship with declared emergencies (scenario risk) so that comparing them for equivalent treatment is irrational.

Q. Do any other, more recent Commission orders address 90/10 sharing for deferrals?

A. Yes. In NW Natural's environmental remediation deferral (Dockets UM 1635/1708) the Commission stated "[w]e do not adopt Staff's proposal of a 90/10 sharing of costs … and conclude that, given that there is limited discretion in the work the company is being required to do, the prudency reviews and application of the earnings test will provide sufficient incentives for NW Natural to minimize expenses."[26] We also note that Commission Order No. 21-309 pertaining to PGE's deferrals for declared emergencies specifically states that, with regard to sharing, "the deferred balance is subject to *full utility recovery*, pending a prudence review" (emphasis added).[27] In other words, the Commission order that specifically

[25] Commission Order 07-049, page 20.
[26] Commission Order 15-049, page 11.
[27] Commission Order 21-309, page 3.

addresses emergency deferrals is inconsistent with Staff's sharing proposal. In summary, we can only conclude that Staff is cherry-picking by relying on outdated Order No. 93-257 and inapplicable Order No. 07-049 to avoid the more pertinent Orders Nos. 05-1070, 15-049, 17-071, and 21-309.

Q. How do you respond to AWEC's assertion regarding offsetting deferrals not having a significant impact on earnings?

A. This would only be true if they are comparable and treated equally. If the deferrals represent both stochastic and scenario risks and the significantly different thresholds are applied, AWEC's statement is not true.

Q. Please elaborate on your characterization of the three deferrals based on their risk.

A. Commission Order No. 05-1070 summarizes the definitions of the risks as the: "distinction between risks that can be predicted to occur as part of the normal course of events, classified as stochastic risks, and risks that are not susceptible to prediction and quantification, classified as scenario risks."[28] The emergency deferrals clearly represent scenario risk which is why the Commission issued Order No. 21-259 (Docket UM 2181) to allow pre-filed deferrals for such unpredictable events. Staff also observes that, regarding the ice storm emergency "Staff considers a storm with this amount of damage to be a scenario risk."[29] Because the wildfire emergency is even more unpredictable and comparably costly, it also represents scenario risk.

Q. How is the Boardman deferral stochastic risk?

A. The Boardman deferral represents stochastic risk because it was foreseen for 10 years. As CUB notes "[i]n November 2010, the Commission acknowledged PGE's plan to operate

[28] Commission Order 05-1070, page 3.
[29] Staff/2600, Moore-Dlouhy-Storm/8.

Boardman until 2020. In December 2010, the Oregon Environmental Quality Commission approved new emissions rules that allowed PGE to comply with regional haze rules, while closing Boardman in 2020."[30] Knowing an event is planned, foreseeable, and predictable for 10 years clearly makes it stochastic.

Q. How do you respond to Staff's argument that the Boardman deferral is subject to "extenuating circumstances" and that this would effectively negate the stochastic categorization?

A. Staff's explanation for extenuating circumstance amounts to: "As of the date of this testimony, PGE has collected, for more than a year, revenue to pay for a plant that was no longer in service."[31] This, however, is no more meaningful than saying that a cost-based deferral has extenuating circumstances because the utility had prudently incurred costs for more than a year that were not recovered in rates. If the argument does not apply symmetrically, it does not reflect a legitimate basis to claim "extenuation."

Q. CUB claims PGE is being inconsistent by stating that the decision to close Boardman was significant, but that the actual closure was not. Please address this concern.

A. CUB is making an apples-to-oranges comparison of the two PGE observations regarding the Boardman closure. The decision to close the Boardman plant occurred primarily over a two-year period in relation to PGE's 2009 Integrated Resource Plan. That process led to a low-cost, base-load plant being transitioned from a 2040 closing date to a 2020 closing date. This was a significant determination for PGE because, as CUB notes, it represented a "major milestone in the clean energy transition for Oregon electric utilities."[32] Once that

[30] CUB/400, Jenks-Gehrke/8-9.
[31] Staff/2600, Moore-Dlouhy-Storm/9.
[32] CUB/400, Jenks-Gehrke/11.

determination was made and recognized by all parties in 2010, then PGE's fulfillment of it ten years later, as scheduled, is neither exceptional nor unpredictable. Because the initial determination and eventual execution represent entirely different circumstances with significantly different time frames, PGE is not being inconsistent.

Q. Can the emergency deferrals begin amortization now and have the earnings review be performed later as part of the consolidated docket as proposed by AWEC?

A. We believe that this would be premature because of the need perform proper earnings reviews in the course of amortization filings. The Oregon Administrative Rules (OAR) are explicit about this requirement by stating that "Upon request for amortization of a deferred account, the energy or large telecommunications utility must provide the Commission with its financial results for a 12-month period or for multiple 12-month periods to allow the Commission to perform an earnings review. The period selected for the earnings review will encompass all or part of the period during which the deferral took place or must be reasonably representative of the deferral period."[33]

Q. Why do the Parties want to begin amortization now and not wait for the required process?

A. The Parties would prefer to begin amortization of the deferrals to reduce their interest rate from the authorized cost of capital to the lower modified blended treasury rate. AWEC is inconsistent, however, by proposing that amortization only begin for the emergency deferrals but not the credit Boardman deferral. More importantly, AWEC's proposal would contradict Commission Order No. 06-507, which states "After amortization of some specific amount in a deferred account is approved, however, we find that the amortized amount differs from an

[33] Oregon Administrative Rule 860-027-0300(9).

investment in terms of the risk associated with it, and with regard to the principles of ratemaking. We find that the amortized portion of a deferred account is a short-term, fixed (as opposed to forecast) investment that will be recouped. We conclude that utilities need only be kept whole on such investments, and we resolve that a rate of return other than a utility's AROR will do so."[34] In other words, AWEC wants to take advantage of the lower interest rate afforded by the amortization phase but keep intact the risk associated with the deferral phase. This is unacceptable and inconsistent with prior Commission statements regarding the purpose of applying a reduced interest rate.

Q. Is PGE profiting from the interest on deferrals?

A. No. That interest is meant to compensate the utility for the time value of money. PGE has incurred the emergency deferrals' costs and must pay for those funds until the costs are recovered from customers. Conversely, if the Commission approves the Boardman deferral and its amortization, that credit interest will also be applied in accordance with Commission Order No. 06-507.

Q. Can PGE begin amortizing the deferrals based on an earnings review using PGE's 2020 Results of Operations Report?

A. We do not believe that 2020 is reasonably representative of the deferral period because none of the ice storm deferral, little of the Boardman deferral and only a portion of the wildfire deferral apply to 2020. In addition, the Commission has yet to approve the Boardman and ice storm deferrals. Based on these factors and OAR 860-027-0300(9), PGE believes the proper approach would be to submit one amortization filing for each of the emergency deferrals and apply the applicable prudence and earnings reviews to each year of those deferrals. This

[34] Commission Order 06-507, page 6.

would facilitate the regulatory process and allow a comprehensive determination of rate impacts based on the amounts to amortize and the length of the amortization period. PGE does not believe the Boardman deferral should be approved, but if it is approved, then its amortization should be addressed in a consistent manner.

Q. Please summarize your arguments about the earnings review and cost sharing.

A. We believe the Parties' proposals are arbitrary and capricious as they propose asymmetric earnings benchmarks, sharing percentages, and reduced ROE while ignoring relevant Commission orders regarding risk, cost sharing, and interest rates. The Parties' proposals also appear to short-cut and/or circumvent the proper application of deferral process. This does not mean that PGE opposes proper earnings reviews, which are required by statute. In fact, we believe they are necessary to establish a quantitative basis for evaluating whether a utility is experiencing significant lag and that they are best done in a consistent and reasonable manner.

D. Deferring Correct Amounts

Q. Do Parties raise any other issues regarding the three deferrals?

A. Yes. AWEC and Staff advocate the removal of labor loadings and certain miscellaneous costs from the wildfire and ice storm deferrals. AWEC also expresses concerns that PGE's on-going wildfire vegetation management activities may not be appropriately tied to the 2020 wildfire event but rather wildfire mitigation in general. We discuss these separately, below.

Loading and Miscellaneous Costs

Q. Please summarize AWEC's and Staff proposal regarding labor loadings and certain miscellaneous costs in the wildfire and ice storm deferrals.

A. AWEC and Staff claim that approximately $900 thousand of labor loadings and certain miscellaneous costs need to be removed from each of these deferrals because they are not incremental costs.

Q. How do you respond?

A. PGE agrees that all labor loadings and allocations, except the payroll tax loading, are inapplicable for these deferrals. Consequently, we have removed these costs from the ice storm deferral and will remove them from the wildfire deferral. We have retained the payroll tax loading because payroll taxes are applicable to all labor costs.

Q. What is your response to the issue of miscellaneous costs?

A. We disagree with AWEC's and Staff's conclusion regarding the miscellaneous costs because these are: 1) incremental to costs in base rates; and 2) directly attributable to the wildfire and ice storm activities. AWEC and Staff simply assume the costs are not incremental based on the title of the costs but provide no further evidence. In total these costs amount to approximately $55 thousand for the ice storm deferral and only $269 for the wildfire deferral.

Wildfire Vegetation Management Activities

Q. Please summarize AWEC's concern regarding the wildfire vegetation management activities.

A. AWEC is concerned that "PGE is treating the UM 2115 2020 Wildfire Deferral as a wildfire mitigation tracking mechanism, rather than as a discrete deferral related to the 2020 Wildfire event. While the 2020 wildfire event occurred 18 months ago, PGE continues to accrue a large amount of vegetation management expenses, which may not be appropriately tied to the

2020 wildfire event. These costs appear to be related to PGE's ongoing wildfire mitigation activities, and not necessarily the 2020 wildfire event."[35]

Q. How do you respond?

A. The referenced on-going work is in fact related to the wildfire emergency and not wildfire mitigation. The work is occurring in the burn areas and includes but is not limited to:

- The removal of tens of thousands of trees impacted by the fire over approximately 20 miles in the Clackamas Corridor from Faraday to Lake Harriet;
- The removal of tens of thousands of trees impacted by the fire over 50 miles of lines through our Bethel Round-Butte 230 kV corridor; and
- Ongoing roadside hazard tree removals in the burn area as part of Clackamas Hydro License obligations along Pipeline Road.

These and other extensive efforts in the burn areas have been hampered by weather, snow, and the limited availability of qualified tree crews for the duration of the project, which is why they are occurring over an extended period.

[35] AWEC/300, Mullins/8-9.

IV. Deferred Transmission Revenue

Q. What was PGE's original proposal?

A. PGE's opening testimony requested that "the Commission authorize a deferral of all incremental revenue associated with the final FERC[36]-approved rates … [and] that the deferral would: 1) be subject to an automatic adjustment clause; 2) be effective as specified in the applicable FERC order; and 3) continue until PGE's next GRC (with the deferral to be re-authorized annually), at which time we will incorporate the updated transmission revenue in the forecast for Other Revenue."[37]

Q. Has PGE filed for the proposed deferral?

A. Yes. PGE submitted its deferral application on December 27, 2021 in Docket UM 2217 and requested it be subject to an automatic adjustment clause. In addition, on December 30, 2021, FERC accepted PGE's proposed Open Access Transmission Tariff (OATT) revisions, suspended them for a nominal period to become effective January 1, 2022, subject to refund, and established hearing and settlement procedures.[38] With Commission approval of PGE's deferral, customers will receive the incremental OATT revenue.

Q. What does AWEC recommend in relation to PGE's transmission revenue deferral?

A. AWEC states that it supports PGE's approach. "Notwithstanding, AWEC recommends that depending on the status of the transmission rate case, amortization of the incremental OATT revenues be reviewed at least annually and considered in conjunction with PGE's Annual Update Tariff or GRC filings."[39]

Q. Do you agree with AWEC's recommendation?

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[36] Federal Energy Regulatory Commission
[37] PGE/200, Tooman-Batzler/11.
[38] See FERC Notational Order 2021-12-30 for FERC Docket ER22-233-000.
[39] AWEC/300, Mullins/24.

A. No. The transmission revenue deferral will be in effect until a FERC order establishes final approved rates in FERC Docket ER22-233-000 and PGE incorporates the associated third-party transmission revenue in its next GRC. Because customers are assured of receiving the benefit of PGE's transmission rate case, we do not see the need to consider this issue in PGE's Annual Update Tariff (AUT) filing. More importantly, it is not appropriate for the AUT because it is not a power cost. Finally, AWEC is free to raise this issue in a subsequent GRC if it occurs prior to FERC issuing a final order approving PGE's OATT rates.

V. Summary and Conclusions

Q. Please summarize your testimony.

A. While we agree with Parties that there are a number of important issues regarding PGE's major deferrals that need to be addressed, these issues are most appropriately handled in the individual dockets in which they are now pending, not in this GRC. In addition, we have shown that the Parties' proposals for resolution of these deferrals are misguided, inconsistent, and contradictory. Commission Orders Nos. 05-1070, 06-507, and 21-309 provide clear guidance on the treatment of deferrals and should be the basis on which they are considered along with ORS 757.259 and OAR 860-027-0300. We believe that this consideration needs to include meaningful earnings reviews for the applicable years of deferral activity and not apply standards that are one-sided, unprecedented, and arbitrary.

Q. What do you request of the Commission?

A. We request that the Commission not approve the Parties' proposals regarding deferrals but instead allow the established deferral dockets to be processed in a consistent and appropriate manner. This will not only allow for the necessary earning reviews but also for the prudence reviews to resolve the issues of miscellaneous costs and vegetation management expenses.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Robert Macfarlane
Teresa Tang

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I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Robert Macfarlane. I am Manager of Pricing and Tariffs for PGE.

My name is Teresa Tang. I am a Regulatory Consultant in Pricing and Tariffs for PGE.

Our qualifications were previously provided in PGE Exhibit 1200.

Q. What is the purpose of this surrebuttal testimony?

A. We provide an update of the overall rate impacts and the impacts to various PGE rate schedules consistent with the Third Partial Stipulation among all stipulating parties reached on January 13, 2022. We also address the following issues raised by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) in Staff Exhibits 2200 and 2700, the Alliance of Western Energy Consumers (AWEC) in AWEC Exhibit 300 and 400, and the Citizen's Utility Board of Oregon (CUB) in CUB Exhibit 400 and 500, Calpine Energy Solutions, LLC (Calpine Solutions) in Calpine Solutions Exhibit 200, and Fred Meyer Stores and Quality Food Centers, divisions of The Kroger Co. (Fred Meyer) in FM Exhibit 200, and Walmart Inc. (Walmart) in Walmart Exhibit 100:

- Marginal Cost Study
- Generation Demand Charge
- Customer Impact offset
- Nonbypassability of various program costs
- Residential Multi-family Basic Charge
- Subtransmission rate for Schedule 90; and
- Service charges and other schedules

Finally, pursuant to Senate Bill 762 (SB 762), we propose an automatic adjustment clause (AAC) for timely recovery of PGE's costs associated with its 2022 Wildfire Mitigation Plan, filed on December 30, 2021 in Docket No. UM 2022, and future wildfire protection plans.

Q. Have any issues been resolved among all parties in the surrebuttal testimonies?

A. Yes, both Staff and CUB agreed with PGE's proposal related to Fee Free Bank Card cost allocation. In addition, PGE accepts customer marginal cost adjustments proposed by AWEC.

Q. Please summarize the updated projected 2022 Cost of Service rate impacts.

A. Table 1, below, summarizes the base rate impacts effective May 9, 2022 for the major rate schedules.

Table 1
Estimated Cost of Service Base Rate Impacts Inclusive of Schedules 122, and 125, and 146.[1]

Schedule	Base Rates
Schedule 7 Residential	5.4%
Schedule 32 Small Nonresidential	6.4%
Schedule 83 31-200 kW	3.2%
Schedule 85 201-4,000 kW	0.4%
Schedule 89 Over 4,000 kW	0.4%
Schedule 90 100 MWa	-3.1%
COS & DA Overall	3.2%

[1] This represents the increase on a cycle basis. Without the Customer Impact Offset (CIO), impacts for Schedules 7, 32, 85, and 89 are 6.7%, 10.4%, -4.9%, and -2.8% respectively.

II. Marginal Cost Studies

Q. In Staff/1400, Staff witness Dr. Max St. Brown made several recommendations related to PGE's generation marginal cost study. What were those recommendations?

A. Those recommendations included:

- Reduce the reserve margin from 12 to 10 percent,
- Net out capacity-resource related energy sales to reduce the cost of capacity, and
- Incorporate an updated higher natural gas price forecast.

Q. In your reply testimony, did you agree to any of those recommendations?

A. Yes, we updated the natural gas price forecast to reflect the most recent estimates.

Q. In Staff/2700, did Staff change its position on either of its other recommendations?

A. Yes, after conducting discovery and reviewing PGE's responses, Staff agreed to accept PGE's initially proposed 12 percent reserve margin.

Q. In Staff/2700, does Staff continue to recommend that PGE net out energy sales to reduce the cost of capacity?

A. Yes, Staff restated their recommendation with no modification to their initial proposal in Staff/1400.

Q. How do you respond?

A. As we indicated in PGE Exhibit 2200, the netting out of energy sales adds unnecessary complexity to the study and has the effect of counteracting AWEC's recommendation to remove wind capacity. Staff indicates that such an approach is recommended by the joint utilities, including PGE, in Docket No. UM 2011. However, the Commission has not adopted a recommendation in Docket No. UM 2011. Given the lack of Commission guidance and added complexity to a simplified marginal cost study, PGE recommends not to adopt Staff's proposal, but rather allow PGE to consider whether to adopt such a modification in future cases once Docket No. UM 2011 is completed.

Q. What changes to PGE's generation marginal cost study does AWEC recommend in AWEC/400?

A. AWEC recommends the following:

- Remove the capacity value of wind when calculating energy costs,
- Include the capacity of pumped hydro for capacity costs,
- Increase the reserve margin from 12 to 16 percent,
- Do not adopt Staff's proposal that PGE net out energy sales, and
- Do not adopt Staff's proposal, adopted by PGE in its reply testimony, to update its natural gas price forecast.

Q. Did PGE address AWEC's first two recommendations in PGE Exhibit 2200?

A. Yes. We continue to recommend using the marginal cost study as filed for this rate case, with the update to the natural gas price forecast provided. Once PGE completes its next IRP and more analysis is complete, PGE can include revisions in a future general rate case to develop a comprehensive and informed generation marginal cost study, that would then identify the energy, capacity, and flexibility values, as well as other benefits to assign to the various customer classes.

Q. How do you respond to AWEC's recommendation to increase the reserve margin from 12 to 16 percent?

A. PGE disagrees. The 12% reserve margin is consistent the reserve requirements identified in PGE's 2019 IRP and with planning and operational standards that allow PGE to provide resource adequacy and system reliability. It appears AWEC was attempting to counteract

Staff's recommendation to lower the reserve margin. Staff has now agreed that a 12% reserve margin as proposed by PGE is appropriate.

Q. How do you respond to AWEC's recommendation not to update the natural gas price forecast?

A. The update to the forecast is not a change in methodology, but to reflect a significant shift in the market. It is an appropriate update that is easily incorporated into the study and, in fact, we already revised the study.

Q. What is PGE's overall response related to the proposed changes to its generation marginal cost study as filed?

A. PGE updated the gas price forecast in its generation marginal cost study using the most recent forecast. PGE has also updated the cost of debt to be consistent with the first stipulation in this docket.

Q. Please discuss AWEC's proposal to add $36 million in other customer costs to the Customer Marginal Cost model.

A. AWEC originally argued that PGE failed to update the Company's Customer Marginal Cost study based on PGE's updated unbundling methodology and proposed to add $44 million in other customer costs to the Customer Marginal Cost model. PGE initially disagreed with AWECs proposal, however, after AWEC data requests 336, 337, and 338 PGE became aware of an error in the allocation of multiple departments in its Customer Marginal Cost model. PGE therefore changes its position to agreeing with twenty-one out of the proposed twenty-three additions of departments to the other category of the Customer Marginal Cost study AWEC proposed in Exhibit 205 page 1 (PGE does not agree to the addition of the Information Tech Transfers department FERC accounts 9030001 and 9080001 given that this cost is indirect). In AWEC Exhibit 400, page 3, AWEC reiterates their original recommendation with modifications based on PGE's responses to the AWEC data requests 336, 337, and 338 resulting in a new proposed increase to the Customer Marginal Cost model of $36 million in other customer costs.

Q. Does PGE agree with this proposal?

A. Yes. AWECs proposal is reasonable, and their proposed allocation is appropriate.

III. Generation Demand Charge

Q. What are the parties' positions on this issue?

A. Staff and Walmart recommend PGE introduce on-peak generation demand charges for Schedules 83 and 85 customers. However, none of the parties have brought in any new evidence or directly responded to PGE's comment on this issue in their reply testimonies.

PGE continues to believe that it is appropriate to consider the on-peak generation demand charges until after the resource adequacy (RA) issues are addressed in Docket No. UM 2143. A generation demand charge can send price signals to customers to manage on-peak consumption. However, it will add complexity and future alignment challenges on customer pricing equity and structure parity. The current pricing design in Schedule 83 and 85 strikes a reasonable balance among all the pricing principles, revenue recovery and fairness.

IV. Customer Impact Offset

Q. Please summarize PGE's proposal on the Customer Impact Offset (CIO)?

A. As noted in our prior testimony, a CIO is a mechanism that represents justified departures from strict cost-of-service allocations to achieve improvements or equity in rate design.[2] PGE proposes a reasonable rate impact to Schedule 7 customers. PGE also proposes to limit the rate impact to non-lighting Schedules (Schedule 32, 38, and 47) customers to twice of the overall increase. The rate impact is mitigated by decreasing the distribution charges for these schedules and increasing the system usage charges for Schedule 85 and 89, along with their direct access equivalents. Schedules 85 and 89 should experience similar price changes. In PGE opening and reply testimony, PGE didn't propose to apply a CIO to Schedule 90, since during the past three AUTs, Schedule 90 has experienced higher than average price increases compared to other schedules. The price increase for Schedule 90 was approximately 50 percent higher than the total cost of service (COS) prices increase from three past AUTs. All parties agree that Schedule 90 remaining on COS will help PGE to keep prices as low as possible and ensure reliable and resilient services to all the customers.

Q. What are Staff's and CUB's main recommendation on CIO?

A. Staff continues to oppose rate decreases to any schedule while there are significant rate increases in one case. CUB explicitly agrees with Staff's position and proposed rate impact floor as zero percent in the case.

Q. How does PGE respond to Staff and CUB?

A. A rate change to a specific customer class is a result of various components, such as marginal cost study, rate design and customer energy consumption profiles, etc. The rate spread process

[2] *See* PGE/2200, Macfarlane-Tang/11.

is a holistic process and PGE has taken many aspects in its consideration. The updates to these components can result in a rate increase for some classes, but a rate decrease for other classes, even the total customer class rate change is an increase. The overall rate impact doesn't parallelly transfer to each rate class proportionally.

Q. Is the update to PGE's marginal cost study one of the reasons that residential and small commercial customers see a rate increase and large industrial customers see a rate decrease in this GRC? Please elaborate.

A. Yes. For example, in the distribution marginal cost study, residential and small commercial customers (Schedule 7 and 32) feeder backbone and feeder tapline costs increased about 42 percent, but for large commercial and industrial customers (Schedule 89 and 90) the same cost decreased about 8 percent. On the other hand, the number of kW for distribution demand charge from large commercial and industrial customers on average is about 43 percent higher than what was in the last GRC (UE 335). More kW is used to spread the distribution cost over and lower the unit rates. For the residential and small commercial customers, by contrast, the number of MWh for volumetric distribution charge was reduced by approximately 5 percent. More distribution costs are spread over fewer MWh, and the unit prices increase even more.

Q. CUB points out that "PGE has been subjected to several emergencies" [3] **between 2020-2021. Is the distribution marginal cost increase for residential and small commercial customers a result of these emergencies?**

A. No. The marginal cost study was prepared in early 2021 and used data inputs mostly in 2019 and early 2020. None of the incremental costs associated with these events has been accounted for in this marginal cost study.

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[3] CUB/400, Jenks-Gehrke/30:7

Q. Please summarize AWEC's position on CIO.

A. AWEC recommends that "CIO be used only to reduce rates for customer classes with rate increases more than the greater of 12 percent or three times the overall rate increase"[4]. AWEC does not agree with Staff and CUB that one class should not receive a rate decrease if the overall rate increases. AWEC claims that "There is no economic basis for limiting any schedule's rate change to an arbitrary number such as zero percent."[5] AWEC also suggests that if the Commission agrees with Staff's position that customer classes generally should not receive decreases while other classes receive increases, the proper way to implement this principle is to modify Staff's proposal to include between-rate-case rate changes when evaluating the percentage change that a schedule has received.[6]

Q. Please compare the impacts in this case to the rates established in PGE's last general rate case, UE 335.

A. PGE summarized the rate change from past three AUTs and this GRC in the following table. The total rate changes are reasonably balanced among different customer classes, though smaller customers have slightly higher impacts.

Table 2 Multiple Rate Changes Since Last GRC (UE 335)

Dockets	Sch 7	Sch 32	Sch 89	Sch 90	Total COS
2020 AUT	1.3%	1.3%	2.1%	2.2%	1.5%
2021 AUT	4.3%	4.2%	6.8%	7.3%	4.9%
2022 AUT	3.2%	3.2%	5.1%	5.5%	3.7%
Total AUTs Change	8.8%	8.7%	14.0%	15.0%	10.1%
UE 394 GRC Change	5.4%	6.4%	0.4%	-3.1%	3.2%
Rate Change Since Last GRC	14.2%	15.1%	14.4%	11.9%	13.3%

[4] AWEC/400, Kaufman/21:23-21:24
[5] AWEC/400, Kaufman/18:6-18:7
[6] AWEC/400, Kaufman/20:5-20:8

PGE agrees with AWEC on not setting an arbitrary price floor to any rate class, but PGE disagrees with AWEC's proposed CIO as it does not provide enough price impact mitigation to residential and small commercial customers in this case.

Q. What is Fred Meyer's position on CIO and how will PGE respond?

A. Fred Meyer continues to advocate an CIO adjustment to Schedule 485 to create an equal rate impact for both Schedule 85 and 485 customers. Fred Meyer mainly complains that "While Schedule 85 customers would receive 2.1% decrease, their direct access counterparts on Schedule 485 would receive a 4.7% increase".[7] PGE does not agree with the way Fred Meyer views the rate impact. The rate change Fred Meyer calculated fails to reflect all of the pricing elements on the total bill of a Schedule 485 customer; therefore, it is not a comprehensive rate impact. A rate impact calculation should include both Schedule 129 and Schedule 139 transition adjustment and those customers pay their electricity service supplier for energy and transmission. Including transition adjustments, Schedule 485 customers will see a rate decrease of 8.7 percent. Factoring in their Electricity Service Suppliers (ESS) bill, impacts are likely similar to the COS standard impacts.

Q. Does Fred Meyer have any concerns about PGE's rate spread in general?

A. No, In the reply testimony, Fred Meyer stated that:

> *For most customer classes, PGE's proposal would result in a reasonable balance between aligning class cost allocation with the underlying cost causation while also mitigating the potential rate shock that might otherwise occur.*[8]

Q. What is PGE's recommendation on CIO?

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[7] FM/200, Bieber/6:12-6:12
[8] FM/200, Bieber/7:5-7:8

A. PGE recommends the Commission to approve the CIO as proposed in this case since it provides a balanced price impact among all customer classes and supports several rate design principles. Without CIO, the small customers (Schedule 32) will see approximately a double-digit price increase; and large customers (Schedule 85 and 89) will see a price decrease. Lowering the small customer price increase and keeping the large customer price impact relatively flat is a reasonable balancing of impacts.

V. Nonbypassability Charges

Q. What nonbypassability charges does PGE propose in this case?

A. PGE proposes to make the following programs nonbypassable to long-term opt out customers: 1) Solar Payment Option, Schedule 137; 2) Transportation Electrification, Schedule 150; and 3) Flexible Load plan. Additionally, PGE suggests the Commission address the nonbypassability issue in Docket No. UM 2024. PGE changed its position on Schedule 135 Demand Response Program in this case and will suggest the Commission address Schedule 135 nonbypassability in Docket No. UM 2024 as well.

PGE seeks to ensure that large nonresidential customers that choose to purchase energy from an ESS pay their fair share of system costs, including costs related to public policy directives. Investments in specified resources to achieve policy goals as legislated by the State, such as Community Solar and the Solar Payment Option, should be recovered from all customers. Similarly, investments in load-stabilizing and system reliability efforts, such as flexible load programs, will provide future benefits/cost avoidance to all users of PGE's distribution system and as such should be funded by all customers, regardless of energy supplier. Transportation Electrification, in support of statewide decarbonization goals and long-term load growth, should also be recovered through all customers.

Q. Does PGE propose nonbypassability charges to the newly introduced Schedule 138?

A. No. PGE does not propose the nonbypassability charges to Schedule 138 Residential Battery Energy Storage Pilot at this time.

Q. Please summarize the parties' position on these four programs' nonbypassability.

A. The following table summarizes the parties' position on nonbypassability applications.

Table 3 Nonbypassability Application to Direct Access Customers by Parties

	PGE	Staff	AWEC	Calpine
1) Solar Payment Option, Schedule 137	Yes	Yes	No	Yes
2) Transportation Electrification, Schedule 150	Yes	Yes	No	Yes**
3) Flexible Load Plan	Yes	not specified*	No	No

**: Staff has not addressed these issues specifically in the Reply Testimony Exhibit Staff/2700.*
***: Calpine agreed with the nonbypassability application but not the cost allocation.*

Q. Any additional comments on nonbypassability from PGE?

A. Nonbypassability is the principle applied at both the Commission and the Legislature that costs of policies, for which there is a societal benefit, are borne by all retail electricity consumers regardless of whether they are served by an investor-owned utility (IOU) or an electricity service supplier (ESS). The mandated costs associated with effectuating public policies should not be bypassed by choosing an alternative energy supplier. The Commission is statutorily required to prevent "unwarranted shifting of costs" from direct access customers to other retail electricity customers.[9] Direct access can harm COS customers through the ability of Long-Term Direct Access (LTDA) and New Load Direct Access (NLDA) customers to bypass costs and risks that are then unfairly borne by COS customers ("bypassability").

In the most recent discussion in Docket No. UM 2024, Staff defined "nonbypassable charges as costs that the legislature directs to be recovered by all customers as well as costs determined by the Commission to be associated with implementing public policy goals related to reliability, equity, decarbonization, resiliency, or other public interests."[10] Expanding non-bypassability to include Community Solar and Solar Pay Option, transportation electrification, demand response[11], and flexible load plan is in alignment with Staff's proposal.

[9] ORS 757.607(1).
[10] On January 12, 2022, Staff circulated the updated issue list in the Docket No. UM 2024
[11] PGE does not take a position on demand response nonbypassability in this case but suggest the Commission to address it in Docket No. UM 2024.

Staff also proposed that "Nonbypassable charges should be allocated to a DA customer in the same method as a COS customer of similar size and load profile" [12]. The cost allocation methods PGE applied to the programs listed above are consistent with the allocation principle Staff proposed.

Q. Calpine states that Schedule 150 cost allocation should be based on the distribution revenue instead of the total revenue as proposed by PGE. Does PGE agree?

A. PGE does not agree with Calpine on this allocation method. Schedule 150 supports the state's transportation electrification policies and will bring economic and societal benefits to all the customers in Oregon. Following the cost-causation principles in rate design, this cost should be allocated to customers on the equal percentage base of the total energy bill a customer pays.

Q. AWEC and Calpine suggest the Commission reject PGE's proposal in the general rate case but address them in Docket No. UM 2024. Is their proposal in alignment with PGE's recommendation?

A. Not completely. While Docket No. UM 2024 is under investigation, PGE suggests the Commission accept PGE's proposed nonbypassability in this case and revisit this issue after Docket No. UM 2024 concludes. PGE wants to create a relatively reasonable pricing structure for all the customers that PGE serves in this rapidly changing political and utility industrial environment. The nonbypassability proposal is the way to minimize cost subsidization across different customer groups and ensure PGE continues to meet various policy goals in the state. When large nonresidential customers choose to purchase energy from an alternate electricity supplier, it is our obligation to protect all customers and ensure that customers departing PGE's supply service pay their fair share of system costs, including costs related to public

[12] On January 12, 2022, Staff circulated the updated issue list in the Docket UM 2024

policy directives and resource adequacy. If the Commission rejects PGE's proposal and PGE's ability to recover nonbypassability costs from direct access customers in this general rate case, the cross subsidization will be worsened and COS customers mostly likely will see a higher price increase than PGE proposed cost-based rate in the case.

Q. In Docket No. UM 2024, Staff stated that "(Staff is) open to including a list of conditions in the rule that make costs associated with a policy non-bypassable." [13]. **Is this consistent with what PGE is proposing?**

A. Yes. PGE is mindful of the costs of each proposed program and plan. For example, in Flexible Load Plan, PGE considers various scenarios when PGE either underspends or overspends the established plan amount in conjunction with either under- or over achievement of plan goals[14]. PGE will make sure all the costs requested for recovery are fair, reasonable, and prudent. PGE will evaluate every proposed program cost allocation and make sure the cost allocation method is consistent with what will be concluded from Docket No. UM 2024 and any future related proceedings.

[13] On January 12, 2022, Staff circulated the updated issue list in Docket No. UM 2024

[14] PGE/600, Salmi Klotz/10:3-11:4

VI. Residential Basic Charge

Q. What are Parties' recommendations relating to the residential basic charge?

A. In its initial filing, PGE proposes to bifurcate the $11 basic residential charge and establish an $8 multi-family basic charge and a $12.50 single-family basic charge. Staff and CUB also support the proposed decreased charge for multifamily customers, but do not agree with the proposed increase for single-family customers. CUB's concern is that PGE has increased the residential basic charge in the past five years and currently has a higher charge than other utilities in the region. They recommend shifting the $9.7 million in expected revenue loss from the single-family basic charge to the variable distribution charge levied on all residential customers. Staff's concern is the impact to single-family customers with low usage (i.e., lower bills) who would experience a larger relative bill increase.

Q. Why does PGE propose to increase the single-family basic charge?

A. PGE proposes to increase the single-family basic charge to reflect the cost causation principle in rate design. In Exhibit 1205, PGE demonstrates that the cost of serving a residential customer in a single-family dwelling was about 27 percent higher than serving residential customers in multi-family dwellings. Increasing the basic charge for single family customers shares the same rate design principle applied to multi-family customers. Accepting the multi-family basic charge decrease but rejecting the increase to single-family basic charge is inequitable and should be rejected by the Commission. Without this increase to single-family basic charge, approximately $9.7 million in revenue that is currently collected via the basic charge must be recovered through volumetric charges and PGE will bear a greater risk to recover that portion of fixed costs.

PGE compared the fixed portion of residential customer bills from the last GRC (UE 335) and what's in this GRC in Table 4. The percentage of the fixed portion for a single-family is very similar to that in PGE's previous GRC. It also shows with the proposed basic charges, the spread between single-family and multi-family is more reasonable than what's in the last GRC. In the last GRC, a single-family customer pays a lower portion of the fixed cost in the total bill than a multi-family customer does, which is contradictory to the fact that the fixed cost of serving a single-family customer is higher than the fixed cost serving a multi-family customer.

Table 4 Fixed Portion in Residential Customer Bills

	Average Customer Bill	Basic Charge	Fixed Portion of Bill
UE 335 (2019)			
Single-family	$110	$11.00	10.0%
Multifamily	$77	$11.00	14.4%
UE 394 proposal (2022)			
Single-family	$123	$12.50	10.2%
Multifamily	$82	$8.00	9.7%

Q. When was PGE's last material increase in its residential basic charge?

A. The residential basic charge increased from $5.50 to $10.00 in 2001, twenty years ago. The average increase rate of 1.1% over twenty years is well below the average inflation rate of 2.1%[15]. PGE concurs with CUB that the residential basic charge was increased from $10.00 to $10.50 in 2016 (UE 294) and from $10.50 to $11.00 in 2018 (UE 319) but asserts that the last time the basic charge was significantly increased was in 2001, from $5.50 to $10.00. Additionally, the residential basic charge was decreased from $10.00 to $9.00 in 2011 and

[15] The Oregon Office of Economic Analysis (2002-2021) CPI

held constant for three years (2011-2013). PGE is not seeking an increase to the average residential basic charge in this rate case but acknowledges that in bifurcating the current average basic charge, single-family customers will experience an increase to the basic charges.

Q. Does PGE have concerns about recovery of the fixed charge if the residential basic charge is decreased for multi-family customers and not increased for single-family customers?

A. Yes. PGE agreed to sunset the Decoupling mechanism in the Third Partial Stipulation in this case. Decoupling is a regulatory policy tool used to ensure that volumetric recovery of Commission approved fixed costs do not induce unreasonable levels of financial volatility which harms all customers. Under PGE's standard rates, a large portion of PGE's fixed costs are recovered with volumetric rates. Without Decoupling in place, the recovery of fixed costs has greater uncertainty in the future. If PGE does not increase the single-family basic charge to balance the decrease in the multi-family basic charge, and instead shifts additional fixed costs to volumetric recovery, PGE will get double hit on fixed cost recovery due to these changes becoming effective concurrently.

Q. Some might argue that low use or low-income residential customers may be harmed by an increase to the basic charge for single family customers. Did PGE file a residential low-income offering prior to the effective date of this case?

A. Yes. PGE filed an interim bill discount option to income-qualified residential customers on January 13, 2022. This option has a three-tiered, percent of bill discount structure which can provide financial benefits to customers with lower household income and higher electricity bills. The interim bill supports the statewide electricity bill affordability and energy burden investigation. The discount PGE offers to the income-qualified residential customers expected to more than cover any increase to the basic charge for single family residential customers, assuming it is approved by the Commission.

Q. What is your recommendation?

A. We recommend the Commission approve PGE's initial proposal to bifurcate the residential basic charge of $11 and establish an $8 multi-family basic charge and a $12.50 single-family basic charge.

VII. Schedule 90 Subtransmission Rate

Q. What is AWEC's proposal on Schedule 90 Subtransmission rate?

A. AWEC states that Schedule 90 should include a subtransmission rate since PGE has proposed to lower the eligibility threshold for Schedule 90 from 100 average MW (aMW) to 30 aMW. Schedule 90 will become available to more customers and adding a subtransmission rate will provide more options to customers and make it consistent with PGE's Schedule 89 rate structure.

Q. Do other parties support AWEC's proposal that PGE offer a Schedule 90 Subtransmission rate?

A. Staff supports AWEC's proposal that PGE offer a Schedule 90 Subtransmission rate. Other parties have taken no position.

Q. Does PGE agree with this proposal?

A. No. PGE continues to oppose introducing a subtransmission rate option for Schedule 90. As mentioned in PGE's reply testimony, PGE's largest customers are all primary voltage and only five legacy customers are on the Schedule 89 subtransmission rate. No new subtransmission services have been initiated in the last 16 years.[16]

Q. Does PGE have additional concerns with AWEC's proposal?

A. Yes, PGE has concerns that offering a subtransmission rate option to Schedule 90 could introduce safety and reliability issues on the bulk electric system. Customers who are on a subtransmission rate build and own the substation to serve their load. It is the customer's responsibility to maintain a safe and reliable asset. However, if there is a safety and reliability

[16] PGE/2200, Macfarlane-Tang/17.

issue at a customer owned substation it may impose a strain on the bulk electric system as PGE relies on it to service over 900,000 customers in Oregon.

Q. Does PGE have any examples of legacy subtransmission customers imposing a strain on the bulk electric system?

A. Yes. A number of legacy customer owned substations were built and interconnected to the bulk electric system decades ago, in accordance with the safety and reliability standards that were required at the time. There are no requirements in place to bring them up to modern standards when standards change over time. For example, PGE recently examined a leased substation from an industrial customer and found out that the substation was not maintained to the current standards. In another example a fuse in a customer owned substation was too close to a transformer. The fuse blew and caused a fuel leak. Due to this safety issue PGE linemen could not enter the substation to stop the fuel leak before the entire substation was de-energized. Due to this interruption, the customer lost all their production while the substation was offline which had a significant economic impact on the customer. Poorly maintained substations can raise safety concerns and prevent PGE from providing technical services for customers. PGE recommends if the Commission does adopt a Subtransmission rate for Schedule 90, the Commission ensure standards are in place to ensure customer owned substations are built and maintained to the same standards applicable to PGE.

Q. Are customer owned substations required to be built to the same standards as a PGE owned substation?

A. Yes, customers are required to build to the minimum requirements at the time the substation is constructed. PGE posts these requirements in its Facility Connection Requirements for Loads document on its OASIS site, in Exhibit 3003. As mentioned previously, there is no current requirement that requires the customer to upgrade the substation when standards change over time.

Q. If PGE offers a subtransmission rate for Schedule 90, could it create upward price pressure on other customer classes?

A. Yes. Offering a subtransmission rate for Schedule 90 will significantly reduce the amount of revenue PGE receives from industrial customers. As Dr. Kaufman points out in his opening testimony, "Subtransmission delivery typically bypasses distribution substations"[17]. The distribution rate that a subtransmission customer pays is about half of the distribution rates that customers served by secondary and primary service pay. Finally, if a Schedule 90 subtransmission customer were to go on Direct Access, PGE would no longer recover enough revenue via the distribution charges from the remaining customers. This would add upward pressure on prices for non-participating customers who would then be allocated the remaining fixed costs.

Q. Why is PGE advocating that now is not the right time to introduce a subtransmission rate for Schedule 90?

A. PGE already offers a subtransmission rate under Schedule 89. The load requirements to be placed on Schedule 90 are significantly higher than under Schedule 89. For this reason, extending subtransmission to Schedule 90 needs to be thoughtfully studied before implementation. PGE recommends the Commission decline to implement a Schedule 90 subtransmission rate in this GRC and allow PGE to study this issue with stakeholders to determine whether an appropriate solution can be agreed upon. PGE will commit to studying this further and addressing it in a future GRC.

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[17] AWEC 100,Kaufman 50-14

VIII. Service Charges

Q. Parties continue to propose two changes to service charge related fees and charges. Please summarize those proposals.

A. The following changes are proposed to service charge items in PGE's tariff:

a. Staff and CUB do not support PGE's Residential line extension allowance proposal. They argue that PGE's new residential line extension allowance was approved by the Commission less than a year ago and should not be revisited until June 30, 2024.

b. Staff also asks PGE to provide a service guarantee before charging customers for temporary service.

Q. How does PGE respond to Staff's and CUB's recommendation that PGE should not increase its Residential Line Extension allowance?

A. PGE does not agree with Staff's and CUB's recommendation. As mentioned in PGE's reply testimony, in Order No. 20-483 the Commission approved PGE's request to bifurcate its Residential Line Extension Allowance (LEA) and create two Residential LEAs: an All-Electric LEA category, and an LEA category for residences not primarily heated with electricity. The Commission imposed the following condition in Order No. 20-483 states, " "that PGE provide a review of the line extension allowance using updated data by June 30, 2024." PGE's interpretation of this condition is, PGE cannot update the average energy usage uses as part of the Residential LEA formula, but this condition does not preclude PGE from updating the Residential LEAs it offers to Residential Customers based on the updated Basic and Distribution Charge Revenues proposed in UE 394. The review is meant to evaluate the effectiveness of the bifurcated residential LEA, not the price within the LEA. PGE's proposed Residential LEAs amounts were calculated using the updated Basic and Distribution Charge

Revenues only. PGE used the same average energy usage and revenue multiplier that was used when the Residential LEAs were updated in 2020. It is standard practice to periodically update LEA amounts when prices change.

Q. Is the rate PGE is proposing for the Residential Line Extension Allowance consistent with the core principle that should hold other customers harmless?

A. Yes, the rate PGE is proposing for the Residential LEA comports with the core principle previously used by Staff in their evaluation of Advice 1130 that should hold other customers harmless. Increasing the Residential LEA will not result in higher residential rates.

Q. Why does PGE think now is an appropriate time to update the Residential Line Extension Allowance?

A. PGE proposes to update the Residential LEAs as well as the Commercial LEAs now so that all LEAs will be based on the updated Basic and Distribution Charges from the same GRC. Currently the Residential LEAs are calculated using the Basic and Distribution Charge Revenues from Docket No. UE 335 (the general rate case 2019) and the Commercial LEAs are calculated using the Basic and Distribution Charge Revenues from Docket No. UE 215 (the general rate case 2011). If approved, all allowances would be calculated using the Basic and Distribution Charge Revenues from the same GRC, UE 394.

Q. How does PGE respond to Staff's proposal that PGE implement a service guarantee to Customers requesting temporary service from PGE?

A. PGE still maintains that a service guarantee is unnecessary. As mentioned in PGE's reply testimony, PGE has made great progress since Docket No. UE 319 to improve the customer experience when a customer requests new service from the Company. PGE has created and launched an online tool called PowerPartner on the Company's website where builders and customers can view the status of their projects and communicate with their assigned PGE project manager. This online tool was launched at the end of 2020 and OPUC Consumer Services inquiries about the length of time PGE takes to energize new service have significantly declined. Through October 2021, PGE has only received two OPUC Consumer Services Section inquiries. Of those, zero resulted in an At-Fault finding.

Q. Does PGE have any additional comments to Staff's proposal that a temporary service guarantee is still needed?

A. Yes, Neither Pacific Power nor NW Natural offer a temporary service guarantee to customers. Additionally, CUB in its opening testimony and reply testimony has taken no position on this issue. Since customer advocates have not advocated that PGE implement a temporary service guarantee, PGE maintains offering a temporary service guarantee is unnecessary and would create an unnecessary administrative burden to implement.

IX. Other Schedules

Q. Did parties provide recommendations on other issues or rate schedules?

A. Yes. CUB proposes making PGE's Habitat Support Adder a separate option, accessible to all Schedule 7 and 32 customers regardless of enrollment in other renewable options, and states that PGE's General Rate Case is the appropriate venue to address this in the absence of the Portfolio Options Committee (POC). CUB also proposes alternate tariff language be reflected in Schedule 138 to comply with the Docket No. UE 370 stipulation

Q. How does PGE respond to CUB's testimony that PGE's General Rate Case is the appropriate venue for discussing adding Habitat Support as a standalone option?

A. PGE was unaware that CUB had spoken to the Department of Justice prior to proposing the change in reply testimony. If PGE would have been aware of this information, a more comprehensive reply would have been given in the last round of testimony. That stated, PGE still believes that Docket No. UM 1020 is a more appropriate venue due to the congruency between portfolio options among utilities participating in Docket No. UM 1020 and relationship to existing requirements through that docket. For example, adjustments to rules made via Docket No. UM 1020 would typically apply to both all participating utilities' products. PGE cannot speak to the viability of this kind of change for others. In addition, PGE would need guidance in how other items in the Docket No. UM 1020 docket that pertain to the Habitat Support option and its relationship with PGE's renewable options would be impacted, including the Marketing and Outreach Services Request For Proposal (RFP) and requirement of a third-party marketer.

Habitat Support was an option that was developed as a result of SB 1149 and key product development features. Ongoing oversight was conducted through the POC via Docket No.

UM 1020. It is PGE's understanding that the POC was not formally dissolved but instead put on hold while the OPUC explored if there was a continued role for this stakeholder group and, if so, the optimal scope and structure for the future. During the hiatus, items that the POC would normally handle would be filed with Docket No. UM 1020. PGE has moved forward with that approach filing RFPs for stakeholder review in 2021.

Q. Please explain how the Habitat Support program currently is run?

A. Schedule 7 and 32 customers may add Habitat Support to their participation in PGE's renewable portfolio options (Green Future Choice, Green Future Block, or Green Future Solar). Customers must opt into a PGE renewable portfolio option in order to participate and therefore cannot have had a disconnect for delinquent payment within the last 12 months. Customers who voluntarily opt-in to add Habitat Support to their renewable option are charged a flat $2.50 additional each month. One hundred percent of the $2.50 collected from customers (or around $280k total in 2021) is passed through to a non-profit that administers the habitat support funds. The non-profit fund administrator is selected through a competitive RFP and has been The Nature Conservancy for much of the lifespan of the product.

All administrative costs associated with running the Habitat Support product are borne by PGE's renewable portfolio options. That means that every marketing solicitation that is shared with customers promoting their renewable energy options includes an enrollment option in the Habitat Support option. PGE acts as a bridge between customers who want to support the non-profit agency PGE selects for habitat restoration and passes through the funds.

Q. Would making Habitat Support a standalone option provide customers with more choice?

A. Making Habitat Support its own standalone option would technically provide a customer with another choice to make with regard to their utility bill but not a new choice that they cannot currently make on their own. There is nothing intrinsic about an electric utility that would make core to a customer's philanthropic giving. In fact, customers may retain more benefits by making direct donations to non-profits they are passionate about that can be tax deductible. Customers participating through the Habitat Support option are not provided tax documents and encouraged to consult a tax professional as to whether their participation in the Habitat Support option is actually tax deductible. As customers are paying PGE and PGE is not a non-profit and PGE aggregates all donations into a single check to the non-profit, the viability of a customer hoping to claim the activity on their taxes is low.

Without PGE's involvement, customers can easily research, select a reoccurring donation amount aside from $2.50, or simply make a one-time donation to one or multiple non-profits working on water restoration projects in Oregon. If Habitat Support were to become a standalone option, it would be responsible for the all-in cost of marketing and administering this program. Per Docket No. UM 1020 Order 01-337 and later modified in Docket No. UM 1077 Order 03-208, Portfolio Options must be marketed by a third party and customers participating must bear the full cost of those products. This kind of shift would require PGE to increase the cost of the Habitat Support option to cover its incremental costs or reduce the amount donated to the non-profit fund administrator. Given any non-profit has its own administrative costs, this seems like a shift that would not be the best use of customer dollars.

While PGE agrees that making options available to customers is good, making Habitat Support its own option would not provide the kind of meaningful choice and intuitive connection to options that customers expect from their electric providers. Instead, it could create confusion when discussing PGE's renewable options as the non-profit PGE sends the funds to is a non-profit that is accessible to members of the general public. Customers would be better served by making direct donations to the non-profit, rather than making it a standalone option in PGE's product mix.

Q. Should Habitat Support be a standalone option?

A. No, Habitat Support should not be a standalone option. It does not truly provide customers with more choice and the costs outweigh the benefits when considering making Habitat Support its own option, as outlined in the above testimony.

Q. What is CUB's alternative tariff language proposal for PGE Schedule 138 Energy Storage?

A. CUB believes PGE's proposed Schedule 138 language which enables the Company to recover expenses associated with energy storage pilots not otherwise included in rates is too broad. CUB proposes to change the Schedule 138 Energy Storage cost recovery language to "expenses associated with HB 2193 energy storage pilots"[18] to comply with Docket No. UE 370 stipulation.

Q. How does PGE respond to CUB's alternative tariff language for PGE Schedule 138-Energy Storage?

A. PGE is not in favor of updating Schedule 138 with CUB's alternative tariff language. While PGE does not currently plan to include any other energy storage projects outside of the already approved Energy Storage pilots that were part of HB 2193, PGE would like to have the flexibility to use Schedule 138 for future energy storage pilot cost recovery when and if PGE brings an energy storage pilot proposal to the Commission for approval. Additionally, any

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[18] CUB/500, Gehrke/19:10

future energy storage pilots would need approval through a separate deferral and undergo a prudency review when PGE requests amortization.

Q. Did PGE ignore CUB's UE 335 argument that "UE 335 smart grid investment (Smart Touchpoints software systems replacements) … enables demand response programs that can substitute for generation"?

A. No. PGE specifically noted that "Although Customer Touchpoints provides a platform for smart grid services (e.g., demand response), it does so in the form of processing meter data, converting that to billings, and providing customer service options. Consequently, PGE allocates Customer Touchpoints to the Metering, Billing, and Other Consumer functions. We also allocate a portion to the Distribution function since PGE's meters are assigned to the Distribution function and the meter data management system (MDMS) communicates directly with AMI [advance metering infrastructure]."[19] We also note that PGE testimony has not referred to this program as a smart grid investment or as "Smart Touchpoints." It is the Customer Touchpoints project that consisted of replacing two large software systems: a customer information system and a MDMS.

Q. Are there any costs components of Customer Touchpoints that are specifically attributable to demand response?

A. No.

Q. Are there any savings or efficiencies derived from the implementation of Customer Touchpoints that are specifically attributable to demand response?

A. No.

Q. Does PGE have any other issues in this round of testimony?

[19] PGE/1400, Tooman-Batzler/37.

A. Yes. In regard to the transmission revenue deferral, AWEC "is willing to support PGE's recommendation to defer the incremental OATT revenue and not consider then in this docket."[20] PGE appreciates AWEC's support on this issue and will incorporate the refund of the incremental transmission revenue through a supplemental schedule after the FERC Docket ER22-233-000 is concluded. It is too early to incorporate the refund in this case since there are still uncertainties around the FERC case.

[20] AWEC/300, Mullins/24:15-17

X. Wildfire Mitigation Cost Recovery

Q. Please summarize PGE's proposal related to timely cost recovery for wildfire mitigation (WM) costs.

A. In accordance with SB 762, PGE is introducing Schedule 151 to allow PGE to recover its WM costs as discussed in Exhibit 2800. This new schedule will include an AAC to ensure the timely recovery of PGE's prudently incurred WM costs on an annual basis. Please refer to Exhibit 3004, which includes PGE's proposed Schedule 151, for details.

Q. How would PGE's WM AAC operate?

A. Like any AAC, PGE would submit a deferral application with a forecast of WM O&M and capital spending for the forthcoming year, incremental to what is included in base rates, to be collected from customers as PGE is making the investments. In this case, PGE proposes to update its pending deferral in Docket No. UM 2019 to include the AAC and add the estimated spending. Unless otherwise directed by the Commission, the WM deferral will be amortized over the next calendar year through Schedule 151, subject to a determination that the WM costs were actually incurred, are covered by subsection 3(8) of SB 762, and are prudent. Recovery of these costs is not subject to an earnings review. The AAC in Schedule 151 thus meets the plain language of SB 762 that "all" WM-related costs are recovered in a "timely" fashion.

Q. Is Schedule 151 generally modeled after Schedule 122, the Renewable Resources Automatic Adjustment Clause (RAC)?

A. Yes. The key language of subsection (3)(8) of SB 762 directing timely cost recovery for WM costs is identical to the language of ORS 469A.120(2)(a) directing timely cost recovery for renewable resource portfolio standard (RPS) compliance costs. In Docket No. UM 1330, the Commission implemented that language through an AAC and deferred accounting without an earnings review, as reflected in Schedule 122.[21] Given the use of the same legislative language for cost recovery in the RPS and in SB 762, PGE modeled its WM AAC on the RAC.

Q. Is PGE aware of any regulatory mechanism other than an AAC that would allow PGE to avoid regulatory lag and timely recover its WM costs as SB 762 directs?

A. No. PGE is not aware of any other regulatory mechanism other than an AAC that would allow PGE to fully recover its WM costs without regulatory lag. Including PGE's updated forecast WM costs from its 2022 Wildfire Mitigation Plan in base rates while allowing a deferral for excess costs is a potential interim approach, but the Commission would still need a mechanism for amortizing this deferral and updating rates to satisfy the statute—which leads back to an AAC.

Q. Please explain why Staff's proposed PBR mechanism for WM costs does not allow for timely recovery of costs consistent with SB 762.

A. As PGE explains in Exhibit 2800, Staff's mechanism subjects PGE's prudent WM costs to disallowance based on parameters that are in some cases completely disconnected to the goal of wildfire prevention. In addition, Staff's mechanism introduces significant regulatory lag. Staff asserts that the proposed mechanism would allow PGE to recover costs with "less than a year of regulatory lag,"[31] when in fact the mechanism creates nearly two years of regulatory lag. Below is a summary of the timeline Staff uses to support its conclusion:

- May 5, 2023: PGE submits filing showing incremental expenses from January 1, 2022, through December 31, 2022.
- November 5, 2023: Rate adjustment goes into effect.

[21] *In the Matter of Public Utility Commission of Oregon; Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket UM 1330, Order No. 07-572 (Dec. 17, 2007).

Under this scenario, funds that were invested in January 2022 would not be recovered from customers until November 2023, approximately twenty-two months later. This is a regulatory lag of nearly two years, not less than a year. Staff's mechanism reduces and delays WM cost recovery and thus fails to comply with SB 762's legislative mandate.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	Description
3001	Estimated Impact of Proposed Changes on Customers
3002	Customer Marginal Cost Study Update
3003	Portland General Electric Facility Connection Requirements for Loads
3004	Schedule 151 Wildfire Mitigation Cost Recovery

Exhibit 3001 is voluminous in
size and provided only in
electronic format

PORTLAND GENERAL ELECTRIC
SUMMARY OF MARGINAL COST STUDY

SCHEDULE	SUBTRANSMISSION COSTS	SUBSTATION COSTS	FEEDER BACKBONE COSTS	FEEDER TAPLINE COSTS	SERVICE & TRANSFORMER COSTS	METER COSTS	CUSTOMER COSTS
Schedule 7 Residential							
Single-phase	$4.17	$10.68	$29.14	$40.48	$74.68	$22.05	$72.18
Three-phase	$4.17	$10.68	$29.14	$40.48	$164.36	$51.68	$72.18
Schedule 15 Residential	$4.17	$10.68	$30.41	$40.56	$2.42	N/A	$51.21
Schedule 15 Commercial	$4.17	$10.68	$30.41	$40.56	$2.42	N/A	$48.09
Schedule 32 General Service							
Single-phase	$4.17	$10.68	$35.13	$61.90	$157.85	$47.76	$92.70
Three-phase	$4.17	$10.68	$35.13	$16.39	$265.66	$66.13	$92.70
Schedule 38 TOU							
Single-phase	$4.17	$10.68	$36.04	$63.08	$165.25	$54.31	$324.81
Three-phase	$4.17	$10.68	$36.04	$18.44	$488.06	$108.52	$324.81
Schedule 47 Irrigation							
Single-phase	$4.17	$10.68	$35.13	$58.44	$9.05	$54.86	$84.91
Three-phase	$4.17	$10.68	$35.13	$15.47	$18.00	$75.87	$84.91
Schedule 49 Irrigation							
Single-phase	$4.17	$10.68	$36.04	$60.92	$121.75	$54.86	$284.05
Three-phase	$4.17	$10.68	$36.04	$17.81	$121.75	$65.99	$284.05
Schedule 83 Secondary General Service							
Single-phase	$4.17	$10.68	$36.04	$63.08	$364.47	$54.86	$488.05
Three-phase	$4.17	$10.68	$36.04	$18.44	$974.14	$114.60	$488.05
Schedule 85 Secondary General Service	$4.17	$10.68	$26.84	$6.72	$2,242.07	$123.23	$1,461.94
Schedule 85 Primary General Service	$4.17	$10.68	$26.84	$6.72	$0.00	$1,985.33	$1,461.94
Schedule 89 Secondary	$4.17	$10.68	$70,405	N/A	$17,117.73	$123.23	$7,630.94
Schedule 89 Primary	$4.17	$10.68	$70,405	N/A	$0.00	$2,097.42	$7,630.94
Schedule 89 Subtransmission	$4.17	N/A	$73,568	N/A	N/A	$19,844.95	$7,630.94
Schedule 90 Primary	$4.17	$10.68	$331,061.00	N/A	$0.00	$2,097.42	$45,515.29
Schedules 91 & 95 Streetlighting	$4.17	$10.68	$30.41	$42.63	$2.42	N/A	$362.52
Schedules 92 Traffic Signals	$4.17	$10.68	$30.41	$15.12	$7.72	N/A	$271.30

Portland General Electric

Facility Connection Requirements for Loads

Table of Contents

Scope

Portland General Electric (PGE) has prepared this document to communicate technical requirements for integrating generation resources, transmission lines, and loads into the PGE Transmission System [1]. For the purpose of this document the PGE Transmission System is defined as transmission facilities owned by PGE and operated at voltages 57kV and above, for the purpose of moving power from one area to another or for moving power to a distribution transformer to serve customer load. These technical requirements are not intended to address the interconnection or integration of generation resources into the PGE distribution system. The technical requirements contained herein apply to all new or modified generating resources, transmission lines, or load connections to the PGE Transmission System regardless of type or size. This document specifies the minimum requirements necessary to assure the safe operation and reliability of the PGE Transmission System. The technical requirements in this document are intended to protect the PGE Transmission System and cannot be relied upon to protect Customer facilities. In coordination with PGE, the Customer is responsible for the planning, design, construction, reliability protection, and safe operation and maintenance of the Customer's facilities unless otherwise identified in the construction, operation and/or maintenance agreements.

This document is not intended as a design specification or an instruction manual. The technical requirements stated herein are generally consistent with the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Council (NERC), the WECC, and the Northwest Power Pool (NWPP) principles and practices. The information presented is subject to change.

In cooperation with affected parties, PGE makes the final determination as to whether the new or modified generation resource, transmission line, or load connection meet the technical requirements of this document and provides for the safe and reliable operation of the PGE Transmission System. The Customer is responsible for correcting identified deficiencies in the technical requirements before the Customer's facilities are energized or interconnection operation begins.

Interconnection Requests

All requests for generation resource interconnection service or transmission interconnection service on the PGE Transmission System must be made pursuant to the terms of the PGE Open Access Transmission Tariff (OATT). PGE should be contacted as early in the planning process as possible for any interconnection or load connections to the PGE Transmission System. Studies must be made to determine the Network Upgrades, Transmission Provider's Interconnection Facilities, and/or Contingent Facilities necessary to accommodate the new or materially modified connection. These studies may address the transmission transfer capability, transient stability, voltage stability, losses, voltage regulation, power quality (harmonics, voltage flicker), electromagnetic transients, machine dynamics, ferroresonance, metering requirements, protective relaying, substation grounding, Subsynchronous Resonance, and fault duties.

[1] All capitalized terms have the same meaning assigned to them in the PGE OATT, unless otherwise defined herein

Affected Systems

PGE will determine if any surrounding systems are affected by a proposed interconnection. Affected Systems can include systems within PGE's Balancing Authority Area's metered boundaries. PGE will include such Affected Systems in Feasibility, System Impact, and/or Facilities meetings held with the customer.

PGE will participate with Affected Systems on joint studies coordinated by the interconnection customer, to determine the impact of the interconnection on the Affected Systems' transmission system.

After execution of the Interconnection Agreement, PGE will report the addition and/or modification of facilities to WECC as part of its Annual Progress Report and Significant Additions filing for non-WECC members. Customers who are WECC members will submit additions not considered part of the PGE Transmission System.

Special Disturbance Studies

PGE uses series and shunt capacitors, high-speed reclosing, single-pole tripping and high-speed reactive switching at various locations. These devices and operating modes, as well as other disturbances and imbalances, may cause stress on connected facilities. The Customer is responsible for any studies necessary to evaluate possible stresses on their proposed facilities and for all protective devices/actions that may be necessary for the benefit of their proposed facilities. PGE develops cost estimates on a case-by-case basis when asked to perform Special Disturbance Studies.

General Requirements

Point of Change of Ownership

The Point of Interconnection (POI), as defined in the PGE OATT, is located between the PGE Transmission System and the Customer's facilities and shall be a PGE-owned disconnecting device, such as a switch, on the PGE side of the POI. The disconnecting device must visibly isolate the PGE Transmission System from the Customer's facilities. Safety and operating procedures for the disconnecting device shall comply with the PGE Safety Manual.

The disconnecting device:

- Must be accessible by PGE;
- Must be capable of being locked in the open position and include connections for the installation of safety grounds;
- Must simultaneously open all three phases (gang operated) to the Customer's facilities at 230kV and below;
- Must be manually operated for connections at 230kV and below;

- Shall use simultaneous motor operation of all three phases in lieu of gang operation at 500kV;
- Will not be operated without advance notice to either party, unless an emergency condition requires that the disconnecting device be opened to isolate the Customer's facilities; and
- Must be suitable for safe operation under the conditions of use;

If the disconnecting device is located in a PGE substation or switchyard, any persons accessing the device for inspection, operation, or maintenance must be fully trained and qualified as defined in the applicable OSHA regulations. These persons must also receive training by PGE, at the Customer's expense, on PGE's operating and safety practices and procedures. All clearances will be under the jurisdiction of the PGE T&D Dispatcher. All operations and clearances will follow the procedures in the PGE Electrical System Switching and Tagging Handbook.

If the disconnecting device is located in a substation or switchyard owned by the Customer, a one-line diagram shall be provided to PGE. Revisions to the one-line shall be issued to PGE when changes are made to the document, and the document shall be updated to reflect the current state of the Customer's facilities. PGE shall have operational access to the Customer's interrupting device to de-energize the Interconnection Facilities prior to the operation of the disconnecting device, following agreement between the PGE Grid Operator and the Customer.

Point of Interconnection Configurations

The transmission path must be owned by a FERC registered Transmission Owner. Unless the Customer's Interconnection Facilities are owned by another FERC registered Transmission Owner, PGE must maintain full ownership of the transmission path. The transmission path is any normally closed-through connection, at voltages 115kV and above, from one transmission line or element to another transmission line or element. Components of the transmission path may include, but are not limited to, all circuit breakers, disconnect switches, structures and supports, bus and jumpers, protective relays and devices, communications devices, and SCADA devices. While PGE's 57kV system is not considered part of the Bulk Electric System, the requirements for connections to the 115kV system apply to connections to the 57kV system.

Connection of new Interconnection Facilities into the PGE Transmission System can be accomplished by connecting to an existing 57kV to 500kV substation, with the existing transmission and new Interconnection Facilities terminated by one or more circuit breakers. If there is not a direct connection to an existing substation, a new substation must be constructed to facilitate the Customer's interconnection, in alignment with PGE's standards. An existing 57kV to 500kV transmission line can be looped into a new PGE owned substation. This connection may require the Customer to provide a substation site to PGE for the construction of the interconnecting substation. The new substation will provide line protection for all positions. New in-line sectionalizing stations will not be created.

An alternative, although less desirable option, of interconnecting to the PGE Transmission System can be accomplished by connecting to an existing 57kV or-115kV transmission line by tapping into the line to create a new radial transmission line. This option is not available for 230kV or 500kV connections, or when the tap will be on a line with a sectionalizing station or a selective transfer station. The addition of a tap creates additional exposure to momentary outages for the customers served by these stations. Motor-operated disconnection switches will not be installed at the point of the tap, however manual gang-operated line switches shall be installed on the tap as near the tap point as practicable. Tapped connections or connections to radial lines may result in forced outages during maintenance activities.

A multi-terminal line is created when a tap is added to a transmission line and that tap becomes a source of real power and fault current. A multi-terminal line affects PGE's ability to protect, operate, and maintain the transmission line. The increased complexity of the control and protection schemes affects the system reliability. Additional terminals may also decrease the overall performance and availability of the existing line. PGE determines the feasibility of multi-terminal line connections on a case-by-case basis. Multi-terminal lines will generally only be allowed for a temporary connection while permanent facilities are under construction. Multi-terminal lines are limited to three terminals. If an agreement is reached to establish a multi-terminal line, transfer trip protection and associated communications facilities to the Customer's interrupting device and to the two PGE line terminals must be installed. All additional relays or relaying schemes required will be installed at the Customer's expense.

Atmospheric and Seismic

The effects of wind storms, floods, lightning, elevation, temperature extremes, icing, contamination, and earthquakes must be considered in the design and operation of the connected facilities. The Customer is responsible for determining that the appropriate standards, codes, criteria, recommended practices, guides and prudent utility practices are met for the Customer-owned Interconnection Facilities.

Insulation Coordination

Power system equipment is designed to withstand voltage stresses associated with lightning, switching surges, and temporary overvoltage. PGE will identify the requirements necessary to maintain acceptable levels of PGE Transmission System availability, reliability, insulation margins, and safety. Adding or connecting new generation resources, transmission lines, and loads can change the voltage stresses to which system equipment is subject and may require that equipment be replaced and/or added to control the voltage stress to acceptable levels. Interconnections at 230kV and higher voltages that terminate at a PGE substation may be required to have one or more overhead ground wires and/or surge arresters to provide substation shielding.

When the low-voltage side of a delta-grounded wye transformer becomes a source of real power due to generation exceeding load and a remote-end breaker operates due to a single-phase fault, the high-voltage side of the transformer can experience overvoltages that can affect personnel safety and damage equipment. This type of overvoltage is commonly described as a neutral shift and can increase the voltage on the unfaulted phases to as high as 1.73 per unit. When this condition is expected to occur, the PGE Transmission System must be designed or upgraded to one of the following options:

- Size the high-voltage side equipment to withstand the amplitude and duration of the neutral shift. This can include replacement of existing PGE equipment.

- Rapidly separate the back-feed source from the step-up transformer by tripping a breaker, using either remote relay detection with pilot scheme (transfer trip) or local relay detection of overvoltage condition.
- Provide an effectively grounded system on the high-voltage side of the transformer that is independent of other transmission system connections. Effectively grounded is defined as an $X0/X1 \leq 3$ and $R0/X1 \leq 1$. Methods available to obtain an effective ground on the high-voltage side of the transformer include the following:
  - A transformer with the transmission voltage side connected in a grounded-wye configuration and low voltage side in closed delta.
  - A three-winding transformer with a closed-delta tertiary winding. Both the transmission and distribution side windings are connected in grounded wye.
  - Installation of a grounding transformer on the transmission voltage side.

Substation Ground Grids

Each substation must have a ground grid that is solidly connected to all metallic structures and other non-energized metallic equipment. Under normal and fault conditions the ground grid shall limit the ground potential gradients to levels that will not endanger the safety of people, damage equipment in or immediately adjacent to the substation, or adversely affect continuity of service. The ground grid size and type are in part based on local soil conditions, available electrical fault current magnitudes, and the duration of the fault.

If a new ground grid is close to another substation, the two ground grids may be isolated or connected. If the ground grids are to be isolated, there must be no metallic ground connections between the two substation ground grids. Cable shields, cable sheaths, station service ground sheaths, and overhead transmission shield wires can all inadvertently connect ground grids. If the ground grids are to be connected, the connecting cables must have sufficient capacity to handle fault currents and control ground grid voltage rises. PGE must approve any connection to a PGE substation ground grid.

New interconnection of transmission lines and/or generation resources may substantially increase fault current levels at nearby substations. Modifications to the ground grids of existing substations may be necessary to keep grid voltage rise within safe levels.

Station Service

Alternate station service is a backup source of power, used only in emergency situations or during maintenance when primary station service is not available.

Power provided for local use at a generation resource or substation to operate lighting, heat and auxiliary equipment is termed station service. In addition, power generated by a generator and then consumed by equipment that contributes to the generation process is considered station service. (This is usually the difference between gross generator output and net generator output). Alternate station service is a backup source of power, used only in emergency situations or during maintenance when primary station service is not available.

Station service power is the responsibility of the Customer. The station service requirements of the new facilities, including voltage and reactive requirements shall not impose operating restrictions on the PGE transmission system beyond those specified in applicable NERC, WECC, and NWPP reliability criteria.

Appropriate providers of station service and alternate station service are determined during the connection planning process, including Project Requirements Diagram development and review. Generally, the local distribution provider will be the preferred provider of primary station service for substations and alternate station service for generation resources, unless it is unable to serve the load.

The Customer must allow for station service and alternate station service metering, as specified in this document in the section pertaining to metering.

Circuit Breakers

All circuit breakers and other fault-interrupting devices shall be capable of safely interrupting fault currents for any fault that they may be required to interrupt. The circuit breaker shall have this capability without the use of intentional time delay in clearing, fault reduction schemes, etc. Application shall be in accordance with ANSI/IEEE C37 Standards. These requirements apply to the equipment at the connection point as well as other locations on the PGE Transmission System. Minimum fault-interrupting requirements are supplied by PGE and are based on the greater of the fault duties at the time of the interconnection request or those projected in committed transmission plans.

The circuit breaker shall be capable of performing other duties as required for the specific application. These duties may include: capacitive current switching, load current switching, and out-of-step switching. The circuit breaker shall perform all required duties without creating transient overvoltages that could damage PGE equipment.

Table 1 specifies the operating times typically required of circuit breakers on the PGE Transmission System. System stability considerations may require faster opening times than those listed. Breaker close times are typically four to eight cycles. The automatic recloser times in **Table 1** are the time from interruption to application of the close signal to the circuit breaker. Circuit breaker interrupting time must coordinate with other circuit breakers and protective devices.

Circuit Breaker Operating Times		
Voltage Class	Rated Interrupting Time	Automatic Reclose Time
(kV L-L rms)	(Cycles)	(Cycles)
500kV	2	20 - 90
230kV	≤ 3	60
115kV	3	300 or 900
57kV	3	300 or 900

Table 1: Circuit Breaker Operating Times

Depending on the application, the use of other fault-interrupting devices such as circuit switchers may be allowed. These devices must be tested for the duty in which they are to be applied and they must coordinate with other protective device operating times. Fuses are not suitable for interrupting load at transmission voltages and will not be allowed.

Generator Excitation Equipment

Excitation equipment includes the exciter, automatic voltage regulator, power system stabilizer, and over-excitation limiter. Supplementary controls are required to meet PGE transmission voltage schedules.

All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator. (The intent is that continuous automatic voltage control not be overridden by supplementary power factor or reactive power controls.) Normally the exciter is of the brushless rotating type or the static thyristor type. The excitation system nominal response shall be 2.0 or higher (for definitions see IEEE 421.2). The excitation system nominal response defines combined response time and ceiling voltage. In some cases, the high initial response static type may be required to economically improve power system dynamic performance and transfer capability.

Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities and protective relays.

The voltage regulator shall include a power system stabilizer (PSS) consistent with the requirements in WECC Standard VAR-501-WECC-1. The PSS should be tuned in accordance with WECC PSS Tuning Guidelines and other industry practice. A dual-input integral of accelerating power type of stabilizer (IEEE Type PSS2A or variant) is preferred.

The voltage regulator shall include an overexcitation limiter. The overexcitation limiter shall be of the inverse-time type adjusted to coordinate with the generator field circuit time-overcurrent capability. Operation of the limiter shall cause a reduction of field current to the continuous capability. Automatic voltage regulation shall automatically be restored when system conditions allow field current below the continuous rating. PGE may request connection of the voltage regulator line drop compensation circuit to regulate a virtual location 50–80% through the step-up transformer reactance.

A supplementary automatic control is required to adjust the AVR setpoint to meet the PGE network side voltage schedule. This supplementary control should operate in a 10–30 second time frame and may also balance reactive power output of the power plant generators.

Generator voltage regulators to extent practical should be tuned for fast response to step changes in terminal voltage or voltage reference. Terminal voltage overshoot should generally not exceed 10% for an open circuit step change in voltage test.

Transformers, Shunt Reactors, and Phase Shifters

Transformer tap settings (including those available for under load and deenergized tap changers), reactive control set points, and phase shift angles must be coordinated with PGE to optimize both reactive flows and voltage profiles. Automatic controls may be necessary to maintain these profiles on the interconnected system. Timed changes should be coordinated with time schedules established by the NWPP.

Power Quality Requirements

Power Factor

PGE and the Interconnection Customer shall jointly plan and operate their systems, including reactive devices, so as not to place an undue burden on either Party to supply or absorb reactive power. Reactive power control, including reserves, is required to maintain adequate voltage levels to prevent voltage instabilities and ensure transient stability. Controlling reactive flow can enhance the transfer capability of the affected line and may also reduce system losses. For each POI for load customers that is radial into PGE's transmission system, the power factor requirements are detailed in the applicable PGE tariff schedules.

Synchronous generators shall have an overexcited power factor rating of 0.9 or lower and an under-excited power factor rating of 0.95 or lower. The active power output should be limited to rated power, so that rated continuous reactive power output is available for power system disturbances. Generators and turbines should be designed and operated so that there is additional reactive power capability that can be automatically supplied to the system during a disturbance. The generator continuous reactive power capability shall not be restricted by main or auxiliary equipment, control and protection, or operating procedures. Induction generators inverters shall have reactive power capability similar to synchronous generators. PGE will charge the Customer a reactive demand charge for all reactive power determined to be delivered or absorbed in excess of the stated limits. The demand charge will be as established in PGE's Open Access Transmission Tariff. If PGE is not able to supply or absorb this excess reactive power and additional equipment or construction of facilities is required, or is the most economic method to supply or absorb the reactive power, PGE shall notify the Customer. If the Customer fails to take corrective action as requested by PGE, PGE may perform such corrective action. Any costs incurred by PGE in performing the corrective action shall be charged to and paid by the Customer.

Voltage Fluctuations and Flicker

Voltage fluctuations may be noticeable as visual lighting variations (flicker) and can damage or disrupt the operation of electronic equipment. IEEE Standard 519 provides definitions and limits on acceptable levels of voltage fluctuation. Interconnections to the PGE Transmission System shall comply with the limits set by IEEE 519. If it is determined that the new connection is the source of the fluctuations, the necessary equipment to control the fluctuations to the limits identified in IEEE 519 is the responsibility of the Interconnection Customer.

Harmonics

Harmonics can cause increased thermal heating in transformers, disable solid state equipment and create resonant overvoltages. In order to protect equipment from damage, harmonics must be managed and mitigated. The new connection shall not cause voltage and current harmonics on the PGE Transmission System that exceed the limits specified in IEEE Standard 519. Harmonic distortion is defined as the ratio of the root mean square (rms) value of the harmonic to the rms value of the fundamental voltage or current. If it is determined that the new connection is the source of the harmonic voltage and currents, the necessary equipment to control the harmonic voltage and currents to the limits identified in IEEE 519 is the responsibility of the Interconnection Customer.

System Voltage and Frequency Disturbances

Power system disturbances initiated by system events such as faults and forced equipment outages expose connected generators, transmission lines, and loads to oscillations in voltage and frequency. It is important that generation resources and transmission lines remain in service for dynamic (transient) oscillations that are stable and damped. Each generator must be capable of continuous operation at 0.95 to 1.05 pu voltage and 59.5 to 60.5 Hz, and limited time operation for larger deviations. Over/under voltage and over/under frequency relays are normally installed to protect the generators from extended off-nominal operation.

In order to avoid large-scale blackouts that can result from a major generation or transmission loss during a disturbance, under frequency load shedding has been implemented in the Pacific Northwest. Load is shed in an attempt to stabilize the system by balancing the load with the remaining generation. When system frequency declines, loads are automatically interrupted in discrete steps, with most of the interruptions between 59.3 and 58.6 Hz. If required, automatic under frequency load shedding total trip time, including relay operation time and breaker operation time, shall not exceed 14 cycles.

There are presently no mandated under voltage load shedding requirements within the PGE service territory. If under voltage load shedding becomes mandatory, the Interconnection Customer may be required to participate at that time.

Voltage Schedules

Voltage schedules are necessary to ensure that reactive flows are kept low and that optimum use of reactive control facilities can be maintained. Generators must meet the voltage schedule limits specified by the Transmission Operator. Limitations at generation facilities must not restrict this range of operation. Voltage schedules may be changed at any time to meet transmission requirements, for example, when a line is out of service.

Generator Governor Speed and Frequency Control

Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency. Governors should operate freely to regulate frequency. In the absence of regional requirements for the speed/load control characteristics, governor droop should generally be set at 5% and total governor deadband (intentional plus unintentional) should generally not exceed ±0.06%. These characteristics should in most cases ensure a coordinated and balanced response to grid frequency disturbances. Prime movers operated with valves or gates wide open should control for overspeed/overfrequency.

Reliability and Availability

Each Balancing Authority shall monitor its Balancing Authority Area, including the status of Remedial Action Schemes (RAS) that impact generation or load, in order to maintain generation-load-interchange balance within its Balancing Authority Area and support Interconnection frequency. The PGE Transmission System must be operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the Most Severe Single Contingency (MSSC) and specified multiple Contingencies, where the specified multiple Contingencies are those identified in PGE studies. PGE Transmission System Operators are required to take actions to mitigate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations and to ensure any violations are promptly reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.

All emergency operation involving the PGE Transmission System must be coordinated with the PGE Grid Operator. Each party must participate in any local or regional Remedial Action Schemes as required by PGE or another affected Transmission Operator. All loads tripped by under frequency or under voltage action must not be restored without the Control Area operator's permission. All energy transfer reductions need to be coordinated with the appropriate Control Area Operator and need to be made promptly. All parties have the responsibility for clear communications and to report promptly any suspected problems affecting others.

New generation resource, transmission line, or load connections to the PGE Transmission System shall not impair PGE from taking a generator, transmission line, line section, or other equipment out of service for operations or maintenance purposes. PGE operates and maintains its system to provide reliable customer service while meeting the seasonal and daily peak loads even during equipment outages and system disturbances. New generation resource, transmission line, and load connections must not restrict timely outage coordination, automatic switching, or equipment maintenance scheduling. Preserving reliable service to all PGE customers is essential.

Transmission lines and other facilities should be kept in service when possible. Shutdown duration for maintenance activities on transmission lines shall be kept to a minimum to avoid unnecessary negative impact to the system and customer reliability. The Customer shall plan and coordinate shutdowns with the PGE Dispatcher for planned maintenance activities. Transmission lines may be removed from service for voltage control only after powerflow studies indicate that system reliability will not be degraded below acceptable levels. The entity responsible for operating such transmission line(s) shall promptly notify other affected Control Areas, per the Reliability Coordinator's (RC) procedure for coordination of scheduled outages and notification of forced outages, or other applicable outages, when removing such facilities from and returning them back to service. Automatic and forced outages should be responded to promptly, mitigating any impacts on the remaining system.

When returning a line to service, the Customer's system or portion of system with energized generators must synchronize its equipment to the PGE Transmission System. The exception to this is under large-scale islanding conditions, where the PGE Transmission System will re-synchronize to neighboring systems over major interties. Automatic synchronization shall be supervised by a synchronizing check relay. Loads that are scheduled and available for blackstart are selected to avoid the trip-out of generation units by exceeding frequency and voltage set points. These loads must be included in, and coordinated with, the PGE Restoration Plan. Small generators are generally not included in the blackstart plan.

Devices switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities. Switches designed for sectionalizing, loop switching, or line dropping shall be capable of performing their duty under heavy load and maximum operating voltage conditions.

Protection Requirements

PGE coordinates its protective relays and control schemes to provide for personnel safety and equipment protection and to minimize disruption of services during disturbances. Generation resource, transmission line, and load connections require the addition or modification of protective relays and/or control schemes. The relays and control schemes ensure that faults or other abnormalities initiate prompt and appropriate disconnection from the PGE Transmission System. Sometimes the addition of voltage transformers, current transformers, or transfer trip pilot schemes (transfer trip) are also necessary. The new protection must be compatible with existing protective relay schemes. The

Protection System security and dependability and their relative effects on the power system must be carefully weighed when selecting the Protection System.

Generation interconnection requests, including requests for capacity less than the total installed nameplate capacity behind the POI and surplus interconnection service, will be limited to the output specified in the interconnection agreement. Protection, SCADA, and Communication infrastructure to limit the Customer's output is determined on a case by case basis. Methods of ensuring that the generator output limit is not exceeded may include automatic generator runback or generator tripping. Automatic generator runback is the preferred method to limit unintentional over generation or thermal overloads, but generator tripping will used if the generator is not responsive to the runback signal or in the event of over-generation or thermal overloads for those Customers who may chose to not participate in a generator run back scheme. Generator tripping will be used when studies identify the possibility of system instability if the Interconnection Agreement output limit is exceeded.

The foundation of all PGE line protection is stepped distance for both phase and ground. Where communication capability for transfer trip is available a DUTT/POTT scheme is layered over the stepped distance. Line differential is added as a third level of protection where adequate communication infrastructure exists, and the system configuration requires this level of protection. Transfer trip and line differential are generally not required where the interconnection with the PGE Transmission System is a radial connection to load.

PGE works with the Customer to achieve an installation that meets the Customer's and PGE's requirements. PGE cannot assume any responsibility for protection of the Customer's system. Customers are solely responsible for protecting their system and equipment in such a manner that faults, imbalances, or other disturbances on the PGE Transmission System do not cause damage to Customer facilities. PGE reserves the right to review and recommend changes to the protection system and settings for equipment at the POI.

The protection system must be designed such that the Customer's equipment or system is automatically isolated for the following situations:

- Faults within the Customer's or connected utilities' system,
- Abnormal operating conditions such as equipment failures (e.g. single-phasing), and
- System disturbances requiring isolation (e.g. load shedding).

All transmission lines shall be provided with automatic reclosing capability. 500kV transmission lines and 500kV generator leads that are not directly connected to GSU transformers shall have the capability of single pole trip and reclose. PGE will provide the delays and intervals at the POI to the Customer. Automatic reclosing of generator leads will be evaluated on a case-by-case basis. Breaker reclose supervision (automatic and manual including SCADA) will be required at the POI; e.g., hot bus check, dead line check, synchronization check, etc.

Redundant Protection Systems are required such that no single Protection System component failure would disable the entire Protection System. Electrical separation should be maintained between redundant Protection Systems to reduce the possibility of both systems being disabled by a single event or condition. Dual batteries may be required, but, in all cases, each set of relays must have its own separately protected DC source. Circuit breakers and other interrupting devices shall have dual trip coils and each relay shall be wired to a separate trip coil.

Protection schemes shall be designed with a sufficient number of test switches and isolating devices to provide ease of testing and maintenance without the necessity for lifting wires. Isolating switches shall be alarmed, or operating and maintenance tagging procedures developed and followed to assure switches are not inadvertently left in an open position.

Breaker failure protection is required. Breaker failure functionality shall be redundant and incorporated into the protective relays for each breaker position. Typical breaker failure trip time is 10 cycles. If transfer trip is present, the breaker failure condition shall be communicated to the remote end of the line.

All proposed settings shall be provided to PGE for review. Relay settings for review shall be provided in SEL.RDB format if SEL relays are being utilized and in a mutually agreed upon format for other types of relays. The review package shall include:

- One-line diagrams showing all interrupting devices, ratings and operation times, all instrument transformers and their connections to the relays, all ratios used, and all trip routing;
- Relay schematic drawings for each position; and
- Other drawings that aid PGE in understanding the proposed protection system.

Protection Measures

Protection Systems must be capable of performing their intended function under all system conditions, including during faults. The magnitude of the fault depends on the fault type, system configuration, and fault location. It may be necessary to perform extensive model tests of the protective relay system to provide that is capable of detecting faults for various system configurations. Power system swings, major system disturbances and islanding may require the application of special protective devices or schemes. The following discussion identifies the conditions under which relay schemes must operate.

Phase Fault Detection

The primary tool for phase fault detection is the phase distance element. The protection system shall incorporate phase overcurrent elements used to provide protection during Loss of Potential (LOP) conditions and for Switch On To Fault (SOTF) protection where the protection VTs may be deenergized prior to the breaker closing. Where line differential is present, overcurrent based LOP protection does not need to be activated if the line differential is active.

Ground Fault Detection

The primary tool for ground fault protection is the ground distance element. Residual ground overcurrent elements are used to provide protection during LOP conditions and for SOTF protection where the protection VTs may be deenergized prior to the breaker closing. Directional ground overcurrent elements will be used in Permissive Overreaching Transfer Trip (POTT) to facilitate sensitive detection of high resistance ground faults without compromising security. The ground settings shall be suitable to detect and clear ground faults with 50 ohms of fault resistance at any point on the line.

Islanding

An island may be created when the breakers at the remote end(s) of the transmission(s) line open. This can leave generating resources and any other loads that also are tapped off this line isolated from the power system. Delayed fault clearing, overvoltages, ferroresonance, extended under voltages, and degraded service to other PGE customers can result from this island condition. Unless other arrangements are specifically called out in the interconnection agreement, all generation resources shall have the capability to detect the formation of an island and shall separate from the PGE Transmission System. The generation may form a generation/load island on the Customer's side of the point of interconnection. The generation resource shall not reconnect to the PGE Transmission System until directed to do so by the PGE Grid Operator.

Remedial Action Schemes

The location of the Point of Interconnection, amount of load, and various other system conditions may require a Remedial Action Scheme (RAS). The need for and type of schemes required will be determined as part of the system studies done following the request for a new connection. For example, RAS may be required for stability purposes or out-of-step tripping may be needed for controlled system grid separations. Special breaker tripping or closing schemes (e.g. staggered closing, point-on-wave closing) may be necessary to reduce switching transients. These special protection and control schemes may require standalone and/or redundant relay systems or additional capabilities of particular substation equipment (e.g. independent-pole operation of circuit breakers).

Relay Performance and Transfer Trip Requirements

Relay systems are designed to isolate the transmission line and/or load facilities from the PGE Transmission System. The performance (clearing time speed) of the Protection Systems and the associated isolating devices (breakers, etc.) will vary. The protection equipment of the new connection must at least maintain the performance level of the existing protection equipment at that location. This may require transfer trip (communication aided protection) to ensure high-speed and secure fault clearing. Transfer trip will utilize SEL's Mirrored Bits protocol; line differential, if applied, will be between PGE owned SEL-411L relays and customer owned SEL-411L relays with matching firmware. All protection and transfer trip communications will be fully redundant. Transfer trip is required when any of the following conditions apply to the new connection.

- The new connection is at 115kV or above.
- New transmission lines are created, either by new construction or the insertion of a new substation into an existing transmission line.

- Transient or steady-state studies identify conditions where maintaining system stability requires immediate isolation of the Interconnection Facilities from the PGE Transmission System.
- Special operational control considerations require immediate isolation of the Interconnection Facilities.
- Extended fault duration represents an additional safety hazard to personnel and can cause significant damage to power system equipment (e.g. lines, transformers).
- Slow clearing or other undesirable operations (e.g., extended overvoltages, ferroresonance, etc.), which cannot be resolved by local conventional protection measures, will require the addition of transfer tripping using remote relay detection at other substation sites. This scenario is a distinct possibility should a PGE circuit that connects other customer loads become part of a 'local island' that includes a generator.
- Relay operation times at 57kV and above shall not exceed 1 cycle for local zone 1 tripping and shall not exceed 2 cycles for transfer trip or line current differential tripping.

Synchronizing and Reclosing

The connection shall have a reclosing sequence compatible with the surrounding system. If the connection includes generation the reclosing shall be supervised by synch check elements to ensure reclosing is blocked if voltage or phase angle across the open breaker is not suitable for reclosing. Synch check setting criteria will be provided.

Protection System Performance Monitoring

For all connections at 57kV and higher, the protective relays shall be configured to provide event records (oscillography) and Sequence of Events (SER) records. All connected currents and voltages shall be included in the event records. The SER shall include sufficient points to fully trace any trip back to the protective element and logic elements involved as well as all I/O. A real time monitor will capture and retain records for disturbance that are triggered by conditions as follows:

- A 2% or greater change in the system frequency from the average system frequency during the previous 30 seconds.
- A 5% or greater change in measured voltage or current from the average value measured at the terminal during the previous 30 seconds.
- A Power System Stabilizer (PSS) response of 10% or greater.
- A change of status in the generator's breaker position

The real time monitor will capture records with the following requirements:

- A minimum rate of 240 samples/second at a minimum resolution of 12 bits over the span of the variable being measured.
- A minimum capture record duration shall be the sum of 60 seconds pre-trigger + 240 seconds post trigger, for a total recorded duration of 300 seconds.
- All reports shall be provided as unfiltered data records and graphs of the event. If filtered records are also available, they shall also be included in the report.

- Triggers shall reset after 30 seconds to allow for multiple consecutive triggered events for a maximum of 3 consecutive triggered events.

The following data shall be recorded in its physical value (not pu):

- Terminal phase currents (IA, IB and IC)
- Terminal phase-to-phase voltages (VA-B, VB-C and VA-C)
- PSS output to the voltage regulator summing junction (Generator only)
- Terminal negative sequence currents
- Field voltage (Generator only)
- Field current (Generator only)
- Breaker Position
- Representative turbine fuel source position (i.e. Hydro turbine wicket gate opening, Combustion turbine fuel valve position, Steam turbine main steam valve position, etc.) (Generator only)
- Initiating trigger
- Date and time of trigger

The relays shall be connected to a GPS satellite clock. If monitoring or relay performance indicates inadequate protection of the PGE Transmission System, the owner of the connected facilities will be notified of additional protection requirements or changes.

PGE may require remote access to relay systems at the POI to query their operational history and fault data.

Protection System Selection and Coordination

At the time of the connection request, PGE will supply the Customer with an approved list of protective relay systems considered to be suitable for the interconnection. Should the Customer select a relay system not on the approved list, PGE reserves the right to perform a full set of acceptance tests, at the Customer's expense, prior to granting permission to use the selected protection scheme. Alternatively, the relay vendor or a third party may be asked to perform the acceptance testing of the proposed relay system, up to full Real Time Digital Simulator (RTDS) testing with the proposed relays.

The following are basic considerations that must be used in determining the settings of the protection systems. Depending upon the complexity and criticality of the system at the POI, complete model line testing of the protection system, including the settings and programming, may have to be performed prior to installation to verify the protection system performance.

- Fault study models used for determining protection settings should take into account zero sequence self and mutual impedances. Up-to-date fault study system models shall be used.
- Protection system applications and settings shall not limit transmission use.
- Loadability shall be considered in all applications and the criteria of NERC PRC-023 shall be applied at all transmission line terminals whether PRC-023 is specifically applicable or not.

Similarly, the requirements of PRC-025 shall be applied at all generator lead terminals whether PRC-025 is specifically applicable or not.

- Protection systems should avoid tripping for stable swings on the interconnected transmission systems and shall comply with the requirements of PRC-026.
- Protection system applications and settings should be reviewed whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.
- All protection system mis-operations shall be analyzed per the requirements of NERC PRC-004 and corrective action taken.
- New substations may be subject to the requirements of PRC-002, whether imposed by PGE or by the RC.

System Operation and Data Requirements

All transmission arrangements for power schedules within, across, into or out of the PGE Control Area require metering and telemetering. Transmission arrangements with loads or new transmission facilities may include wheeling, voltage control, and Automatic Generation Control (AGC). The technical plan of service for interconnecting a generation resource, load, or new transmission facility, will include the metering and telemetering equipment consistent with the transmission contract provisions. Such metering and telemetering equipment may be owned, operated, and maintained by PGE or by other parties approved by PGE. Revenue metering, system dispatching, operation, control, transmission scheduling, and power scheduling each have slightly different needs and requirements concerning metering, telemetering, data acquisition, and control.

Telemetering Requirements

PGE's System Control Centers (SCC and CRC) require telemetering data for interconnections at adjacent Control Area boundaries. Continuous telemetering of real power and energy (kW, kWh) and reactive power (kVAr, kVArh) is required for power factor and billing purposes. Some interconnections may require redundant metering and telemetering. The following includes generic requirements:

- For interruptible loads, PGE determines telemetering needs on a case-by-case basis. Connecting eccentric (non-conforming) loads may require an interface to the PGE AGC system. Existing practices throughout North America usually require a warning signal of pre-loading in order to assure that adequate generation reserves are spinning before any sudden load change occurs.
- Telemetering for interconnection of shared or jointly-owned loads or generation commonly use dynamic signals. These signals are usually a calculated portion of an actual metered value. The calculation may include adjustments for losses, changing ratios of customer obligations or shares, or thresholds and limits. Two-way dynamic signals are used when a customer request for MW change can only be met by an actual change in generation. In this case, a return signal is the official response to the request and its integrated value is designated the official meter reading. Previous integration intervals were one hour. Some types of dynamic signals may

require shorter integration intervals. The integration interval is determined by the type of service provided consistent with PGE tariffs to properly account for transmission usage.

- Where a third party is providing ancillary service for the Interconnection Customer, the kWh for the last hour and the operating reserve capability during the next 10 minutes is required with a sampling rate of once per second or some other rate as established by NERC
- Non-traditional sources are sometimes used for supplying ancillary services. If a load provides regulating or contingency reserve services, data requirements for deployment of the reserves will be similar to those applied to generating resources. To the extent that a third party may externally supply regulating or contingency reserve services at the PGE Control Area interconnecting boundary, data requirements for their deployment may be similar to those applied to generating resources.
- Loads such as steel rolling mills, wind tunnels, etc. require additional data to make generation control performance more predictable. Such additional data may include, but not be limited to, precursor signals of expected load changes, etc. SCADA control may also be required. Specific requirements and needs are determined for each load.
- Facilities that will participate in the CAISO Energy Imbalance Market (EIM) must have DNP3 telemetering with 99.90% annual availability and 500 mS maximum latency to PGE's Energy Management System (EMS) at PGE's SCC and CRC control centers.
- Facilities that will not participate in the CAISO EIM but require telemetering must provide DNP3 telemetering with 99.50% annual availability and 500 mS maximum latency to PGE's EMS at SCC and CRC.

Supervisory Control and Data Acquisition (SCADA) Requirements

Transmission line and load interconnections require SCADA control and status indication of the power circuit breakers and associated isolating switches used to connect with PGE. SCADA indication of real and reactive power flows and voltage levels are also required. If the connection is made directly to another utility's transmission system, SCADA control and status indication requirements shall be jointly determined with the Customer, and PGE. SCADA control of circuit breakers and isolating switches that are located at points other than the Point of Interconnection is not normally required, although status indication may be necessary.

Metering

Metering Equipment shall mean all metering equipment installed or to be installed at the new Facility pursuant to the Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, and MV90 data acquisition equipment.

General

PGE and the Customer shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, PGE shall provide and install Metering Equipment at the Point of Interconnection and other locations deemed necessary prior to energization of a new Facility and shall own, operate, test, and maintain such Metering Equipment. Power flows to and from the new Facility shall be measured at or, at PGE's option, compensated to, the Point of Interconnection. Electric service and revenue metering of the auxiliary load associated with the generator plant is required. The Interconnection Customer is responsible for all documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

Check Meters

The Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check PGE's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes revenue billing. The installation, operation and maintenance thereof shall be performed entirely by the Customer in accordance with Good Utility Practice.

Station Service Power

Primary and alternate station service power may also require revenue metering, depending upon its electrical source and electrical location.

Standards

PGE shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

Metering Data

At the Customer's expense, the metered data shall be telemetered to one or more locations designated by PGE. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the new Facility to the Point of Interconnection.

Access

PGE shall always have access to the metering equipment located within the new Facility. PGE shall provide reasonable notice to the Customer when possible prior to using its right of access.

Telecommunication Requirements

Telecommunications facilities shall be tailored to fulfill control, protection, operation, dispatching, scheduling, and revenue metering requirements. At a minimum, telecommunications facilities must be compatible with, and have similar reliability and performance characteristics to that currently used for operation of the PGE Transmission System at the Point of Interconnection. Depending on the performance and reliability requirements of the control and metering systems to be supported, the facilities may consist of any or all of the following:

Microwave Systems

A microwave system requires transmitters, receivers, telecommunication fault alarm equipment, antennas, batteries, and multiplex equipment. It may also include buildings, towers, emergency power systems, mountaintop repeater stations and their associated land access rights, as needed to provide an unobstructed and reliable telecommunications path. Microwave path diversity, equipment redundancy, and/or route redundancy may be required to meet power system reliability requirements by protecting against telecommunications outage caused by equipment failure or atmospheric conditions.

Fiber Optic Systems

A fiber optic system requires light wave transmitters, receivers, telecommunication fault alarm equipment, multiplex equipment, batteries, emergency power systems, fiber optic cable (underground or overhead) and rights-of-way. Cable route redundancy may be required to protect against cable breaks and resulting telecommunications outage.

Common Carrier

Dedicated telecommunication facilities are required for the operation of Main Grid power system control and protection functions. Common carrier telecommunications systems may be considered, subject to reliability and availability requirements and capabilities.

Voice Communications

Voice Communication to the Customer is required whenever any type of telemetering is required. A Dedicated, Direct, Automatic Ringdown Trunk (or equivalent) voice circuit between the appropriate the PGE T&D Dispatchers and the Customer may be required for:

- Loads of 50 MW or greater,
- Eccentric (non-conforming) Loads
- A non-radial interconnection to another electric utility

Independent Voice Communications for coordination of system protection, control, and telecommunication maintenance activities between PGE and the POI should be provided, in addition to the voice telecommunications specified.

Data Communications

Telecommunications for SCADA, RMS, and Telemetering must function at the full performance level before and after any power system fault condition. Service continuity must be restored immediately after the fault without requiring any repair personnel activity.

SCADA Requirements typically include one or more dedicated circuits between the new Point of Interconnection and the PGE Control Centers.

Interchange and Control Telemetering for operations and scheduling applications require two dedicated circuits between the new POI and the PGE Control Centers. Circuits are required to carry DNP3 protocol over serial or Ethernet at a baud rate of 19200 or higher.

Remote interrogation of metering equipment is required for revenue billing. A dedicated circuit for MV90 access is required for Ethernet over VPN between the POI and the appropriate PGE Control Centers.

Telecommunications for Control and Protection

Telecommunications for Control and Protection must function at the full performance level before, during, and after any power system fault condition. The delivery of a false trip or control signal, or the failure to deliver a valid trip signal is unacceptable. Active telecommunication circuits for control and/or protection must not be tested, switched, shorted, grounded or changed in any manner by any worker, unless prior arrangements have been made through the PGE T&D Dispatcher.

New connections to the PGE Transmission System at 500kV, and connections which participate in a RAS, require redundant (i.e. hot-standby or frequency-diversity) telecommunications systems. Alternately routed telecommunication circuits may be used where feasible (to be negotiated between PGE and the Interconnection Customer). New connections to the PGE Transmission System at voltages from 57kV to 230kV, generally do not require redundant telecommunications systems. However, under some circumstances, redundant telecommunications are required to satisfy stability criteria.

Throughput operating times of the telecommunications system must not add unnecessary delay to the clearing or operating times of protection system. Maximum permissible throughput operating times of control schemes are determined by PGE.

In order to provide maintainability and operability between the new connection and the PGE Transmission System, the protection systems and their supporting telecommunications system equipment do not have to be identical but must be functionally compatible. The need or implementation of peripheral capabilities such as signal counters, test switches, etc. are not required to be identical to those used at PGE facilities. During initial engineering of the new interconnection request, PGE and the Interconnection Customer will confirm the communications equipment is compatible between the PGE and Interconnection Customer's systems. Should the Customer choose to use something other than what has been agreed to by PGE, PGE reserves the right to test the equipment system compatibility, prior to installation, at the Interconnection Customer's expense. When applying sophisticated digital telecommunications systems to certain protection schemes, care must be taken to avoid combining approaches with inherent technical conflicts or incompatible methodologies.

Telecommunications during Emergency Conditions

Emergency conditions may develop that affect power system telecommunications with or without directly affecting power transmission system facilities. Examples of telecommunications emergencies include the following:

- Interruption of power service to telecommunications repeater and relay stations
- Telecommunications equipment failure, whether minor or catastrophic
- Interruption or failure of commercial, public telephone network facilities or services
- Damage to telecommunications facilities resulting from accident, acts of vandalism, or natural causes

Equipment redundancy and telecommunications route redundancy can protect against certain kinds of failure and telecommunications path interruption. Where commercial, public telephone network facilities or services support important power system telecommunications, a backup strategy should always be developed to protect against interruption of such services. Backup methodologies could include redundant services, self-healing services, multiple independent routes and/or carriers, and combinations of independent facilities such as wireline and cellular, fiber and radio, etc. Backup telecommunications system equipment such as emergency standby power generators with ample on-site fuel storage, and reserve storage battery capacity must be incorporated in critical telecommunications facilities. Backup equipment should be considered as well for certain non-critical telecommunications to assure continued operation of power system telecommunications during interruption of power services.

A disaster recovery plan should be in place for telecommunications restoration and should be exercised periodically. The disaster recovery plan should include the ability to deploy transportable restoration equipment capable of temporarily bypassing or replacing entire telecommunication stations or major apparatus until permanent repairs can be made.

The operation of power system telecommunications facilities should be continuously monitored at a central alarm point so that trouble can be immediately reported, diagnosed, repaired and service restored. Power system telecommunication sites and facilities should be secured against unauthorized access by means of locked gates, security fences, warning signs, security doors, and entry alarms.

SCHEDULE 151
WILDFIRE MITIGATION COST RECOVERY

PURPOSE

This schedule recovers the costs associated with wildfire mitigation, established to reduce wildfire risks and promote energy system resilience. This adjustment schedule is implemented as an automatic adjustment clause as provided under ORS 757.210 and Subsection 3(8) of Senate Bill 762 (2021).

AVAILABLE

In all territory served by Portland General Electric Company ("PGE").

APPLICABLE

To all bills for Electricity Service.

ADJUSTMENT RATES

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
15/515	0.000 ¢ per kWh
32/532	0.000 ¢ per kWh
38/538	0.000 ¢ per kWh
47	0.000 ¢ per kWh
49/549	0.000 ¢ per kWh
75/575	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
76R/576R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
83/583	0.000 ¢ per kWh
85/485/585	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh

SCHEDULE 151

ADJUSTMENT RATES (Continued)

89/489/589/689		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh
90/490/590	0.000	¢ per kWh
91/491/591	0.000	¢ per kWh
92/492/592	0.000	¢ per kWh
95/495/595	0.000	¢ per kWh

ANNUAL REVENUE REQUIREMENTS

The Annual Revenue Requirements will include all the fixed costs associated transmission (including return on and return of the capital costs), operation and maintenance costs (O&M), income taxes, property taxes, and other fees and costs that are applicable to develop, implement or operate a wildfire protection plan.

DEFERRAL MECHANISM

For each calendar year, the Company will submit a deferral application with forecast O&M and capital spending for the amount incremental to what is included in the base rates set in the most recent general rate case. Unless otherwise directed by the Oregon Public Utility Commission (OPUC), the deferral will be amortized over the next calendar year in Schedule 151, subject to a determination that the costs were actually incurred, are covered by Section 3(8) of SB 762, and are prudent. The balancing account will accrue interest at the Commission-authorized rate for deferred accounts, and the amortization of the deferred amount will not be subject to the provisions of ORS 757.259(5).

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of total revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule.

2. The costs for projects included under this schedule will be updated annually as provided above, and will continue to be recovered under Schedule 151 until such time as the costs are included in base rates.