May 7, 2024 **Via Electronic Filing**

Caroline Thomas Jacobs, Director
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California Natural Resources Agency
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Subject: **Comments of the Public Advocates Office on PG&E's 2025 Wildfire Mitigation Plan Update**

Docket: **2023-2025-WMPs**

Dear Director Thomas Jacobs,

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) respectfully submits the following comments on the 2025 Wildfire Mitigation Plan Update of Pacific Gas and Electric Company (PG&E). Please contact Nathaniel Skinner (Nathaniel.Skinner@cpuc.ca.gov) or Henry Burton (Henry.Burton@cpuc.ca.gov) with any questions relating to these comments.

We respectfully urge the Office of Energy Infrastructure Safety to adopt the recommendations discussed herein.

Sincerely yours,

/s/ ***Marybelle C. Ang***

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I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits these comments on the 2025 Wildfire Mitigation Plan (WMP) Updates submitted by investor-owned electric utilities (IOUs or utilities).[1] These comments are submitted pursuant to the Office of Energy Infrastructure Safety's (Energy Safety) *Revised 2023-2025 Wildfire Mitigation Plan Process and Evaluation Guidelines* (WMP Process Guidelines)[2] and the *Revised 2025 Wildfire Mitigation Plan Update Schedule*.[3]

The 2025 Wildfire Mitigation Plan Update Guidelines (2025 WMP Update Guidelines)[4] establish substantive requirements for these WMP Update submissions, while the WMP Process Guidelines establish a schedule and review process for WMP submissions. Bear Valley Electric Service (BVES), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) submitted 2025 WMP Updates on April 2, 2024.

The WMP Process Guidelines and the 2025 WMP Update schedule permit interested persons to file opening comments on the WMP Updates of BVES, PG&E, SDG&E, and SCE by May 7, 2024 and reply comments by May 17, 2024. In these comments, Cal Advocates addresses PG&E's 2025 WMP Update.[5]

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[1] Many of the Public Utilities Code requirements relating to wildfires apply to "electrical corporations." *See e,g,* Public Utilities Code Section 8386. These comments use the more common term "utilities" and the phrase "electrical corporations" interchangeably to refer to the entities that must comply with the wildfire safety provisions of the Public Utilities Code.

[2] Office of Energy Infrastructure Safety's (Energy Safety), *Revised 2023-2025 Wildfire Mitigation Plan Process and Evaluation Guidelines*, January 31, 2024, in docket 2023-2025-WMPs.

See also: Energy Safety, *Final 2023-2025 Wildfire Mitigation Plan Process and Evaluation Guidelines*, December 6, 2022.

[3] Energy Safety, *Revised 2025 Wildfire Mitigation Plan Update Schedule*, February 22, 2024, in docket 2023-2025-WMPs.

[4] Energy Safety, *2025 Wildfire Mitigation Plan Update Guidelines*, January 31, 2024, in docket 2023-2025-WMPs

[5] PG&E, *2025 Wildfire Mitigation Plan Update*, April 2, 2024 (2025 WMP Update).

II. TABLE OF RECOMMENDATIONS

Item	Recommendation	Timeframe	Section of these Comments
1	Energy Safety should work with PG&E to study the implications of PG&E's new risk model on system hardening, asset inspections, and vegetation management.	2026-2028 WMP	III.A.4
2	Energy Safety should require PG&E to identify necessary and reasonable changes to improve the cost-effectiveness of system hardening, asset inspections, and vegetation management under WDRM v4.	2026-2028 WMP	III.A.4
3	Energy Safety should require PG&E to consider adjustments in system hardening, asset inspections, and vegetation management to ensure planned work appropriately balances safety, reliability, and affordability for PG&E's ratepayers.	2026-2028 WMP	III.A.4
4	Energy Safety should require PG&E to estimate the cost-effectiveness of system hardening projects in its current workplan that are not yet in construction.	Revision notice	IV.A.3
5	Energy Safety should require PG&E to remove any undergrounding project with a cost-benefit ratio below one from its workplan, or replace the project with overhead hardening,	Revision notice	IV.A.3
6	Energy Safety should require PG&E to estimate the actual cost-effectiveness of its past system hardening work based on WDRM v4.	2026-2028 WMP	IV.A.4
7	If a substantial portion of PG&E's past undergrounding projects have had low cost-benefit ratios, Energy Safety should require PG&E to reassess the planned scope of its system hardening plans.	2026-2028 WMP	IV.A.4
8	Energy Safety should require PG&E to re-evaluate the scope of its long-term undergrounding plans.	2026-2028 WMP	IV.A.5

Item	Recommendation	Timeframe	Section of these Comments
9	Energy Safety should require PG&E to analyze alternative system hardening strategies that reasonably balance safety, reliability, and affordability. PG&E should present these alternative strategies for review in its 2026-2028 Base WMP.	2026-2028 WMP	IV.A.5
10	Energy Safety should require PG&E to file quarterly updates on its REFCL pilot.	Quarterly until pilot is complete	V.A.3
11	Energy Safety should require PG&E to report the results of its REFCL pilot and either present a plan to expand REFCL, or demonstrate how doing so is not in the best interests of Californians.	2026-2028 WMP	V.A.3
12	Energy Safety should require PG&E to re-evaluate its methodology for determining detailed inspection frequencies.	2026-2028 WMP	VI.A.3
13	Energy Safety should require PG&E to analyze the benefits and costs of expanding the scope of its detailed inspections.	2026-2028 WMP	VI.A.3
14	Energy Safety should direct PG&E to fully describe and justify all changes it has made to its inspection strategy since its 2023-2025 Base WMP.	Revision notice	VI.B.1
15	Energy Safety should require PG&E to report actual inspection results using its new process.	Quarterly in 2024 and 2025	VI.B.1
16	Energy Safety should require PG&E to explain discrepancies in QC pass rates and provide a clear explanation for how it calculates QC pass rates.	Revision notice	VI.C.2
17	Energy Safety should require PG&E to address data quality issues in its asset inspections QA/QC.	2026-2028 WMP	VI.C.2
18	Energy Safety should work with industry experts and interested stakeholders to develop guidance on QA/QC data collection and standardization procedures	2026-2028 WMP guidelines	VI.C.3
19	Energy Safety should require PG&E to investigate and explain its high failure rate for quality control specific to intrusive inspections.	Revision notice	VI.D.2

Item	Recommendation	Timeframe	Section of these Comments
20	Energy Safety should require PG&E to define and begin reporting an updated quality control pass rate for intrusive inspections. PG&E should report these pass rates retroactively for 2023 and begin reporting quarterly henceforth.	Quarterly in 2024 and 2025	VI.D.2
21	Energy Safety should require PG&E to collaborate with peer utilities to determine an appropriate QC timeline.	2026-2028 WMP	VI.E.2
22	Energy Safety should require PG&E to revise and resubmit its WMP to fully comply with ACI PG&E-23-05.	Revision notice	VII.A.6

III. RISK MODELING

A. PG&E's newest version of its risk model represents a substantial shift in risk distribution and ranking.

In 2023, PG&E developed version 4 of its Wildfire Distribution Risk Model (WDRM v4).[6] PG&E states that the new version incorporates several changes to both the probability and consequence sub-models[7] and represents a substantial shift in the distribution of wildfire risk in PG&E's territory as compared to the previous version (WDRM v3).

1. Wildfire risk is less concentrated under WDRM v4 than previously shown by WDRM v3.

PG&E's WDRM v4 shows less concentrated wildfire risk in PG&E's system compared to WDRM v3.[8] PG&E's WDRM v3 estimated that the riskiest 10,000 circuit miles in PG&E's system carried approximately 78 percent of PG&E's total wildfire risk.[9] Under WDRM v4, the same number of miles carries only 56 percent of PG&E's total wildfire risk.[10] Figure 1 illustrates this difference.

[6] PG&E's 2025 WMP Update at 6.

[7] Detailed in Section B.1.1 in PG&E's 2025 WMP Update at 6-12.

[8] See Figure PG&E-B.1.1-3 in PG&E's 2025 WMP Update at 12. The risk buydown curve shows the cumulative percentage of wildfire risk carried by PG&E's riskiest circuit segments.

[9] Analysis of PG&E's WDRM v3, provided in response to data request CalAdvocates-PG&E-2022WMP-31, question 7. To estimate total risk carried by each circuit segments, Cal Advocates multiplied the system hardening composite risk score by the overhead circuit miles for each circuit segment. The riskiest 699 circuit segments are composed of 10,006 overhead miles and cumulatively carry 77.5 percent of the total wildfire risk.

[10] Analysis of PG&E's WDRM v4, provided in response to data request CalAdvocates-PG&E-2025WMP-05, question 5. To estimate total risk carried by each circuit segments, Cal Advocates multiplied the system hardening composite risk score by the overhead circuit miles for each circuit segment. The riskiest 938 circuit segments are composed of 10,009 overhead miles and cumulatively carry 55.7 percent of the total wildfire risk.

Figure 1:

Wildfire risk associated with PG&E's riskiest 10,000 circuit miles[11]

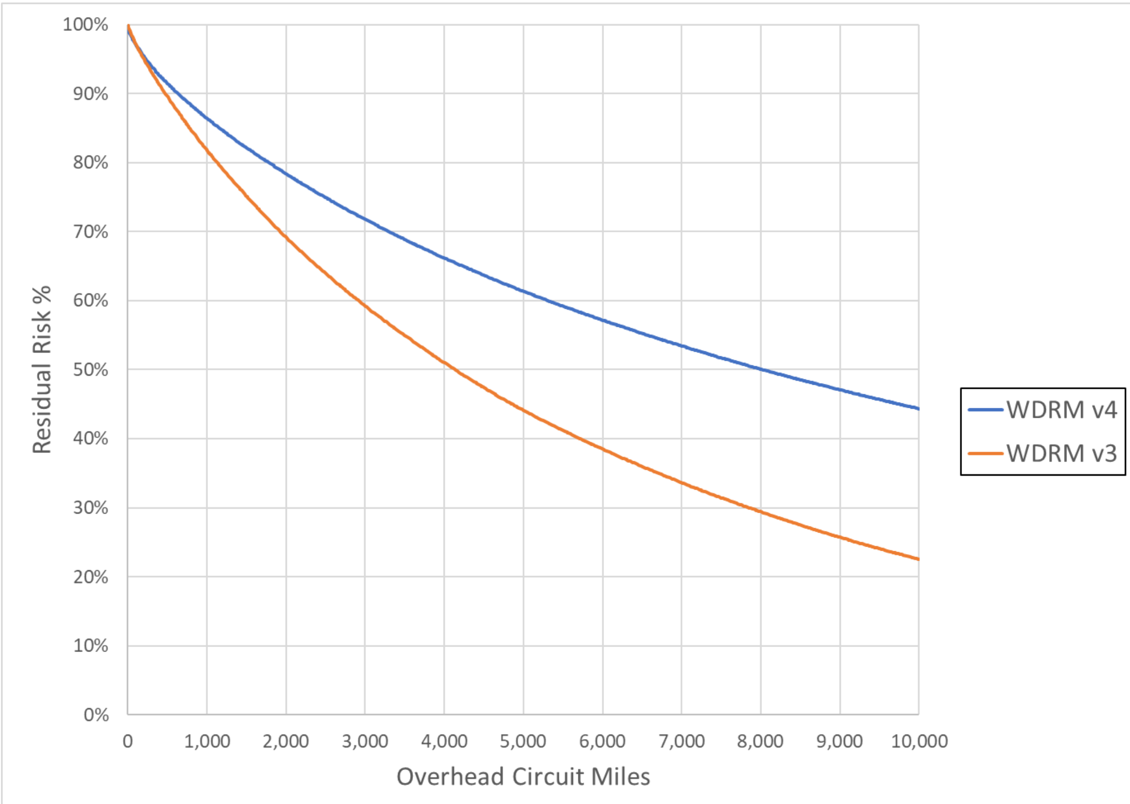

Figure 1 shows overhead circuit-mileage on the X-axis, organized sequentially from most to least risky. On the Y-axis, it shows the percentage of wildfire risk remaining. The curves represent what would happen if PG&E hardened its overhead circuit-miles in the HFTD in sequential fashion, starting with the riskiest miles – the "risk buydown curve." Notably, the curve for WDRM v4 (in blue) declines much more gradually, meaning that it takes more

[11] The orange line is based on the circuit-segment-level output of PG&E's WDRM v3, provided in response to data request CalAdvocates-PG&E-2022WMP-31, question 7. The blue line is based on the circuit-segment-level output of PG&E's WDRM v4, provided in response to data request CalAdvocates-PG&E-2025WMP-05, question 5. For both models, Cal Advocates estimated total risk by multiplying the system hardening composite risk score by the overhead circuit miles for each circuit segment.

The system hardening risk was chosen as the focus for this chart as it directly influences PG&E's system hardening programs, which are discussed in more detail later in these comments.

Note: the trend in Figure 1 is comparable to Figure PG&E-B.1.1-3 in PG&E's 2025 WMP Update. However, Cal Advocates finds it more informative to plot the risk buydown curve over circuit miles rather than circuit segments, which vary in length.

hardening to achieve the same amount of risk reduction. This reflects the fact that WDRM v4 estimates that wildfire risk is more broadly dispersed across PG&E's distribution system.

Despite the shift in risk concentration between WDRM v3 and WDRM v4, PG&E maintains that all versions of its risk model are valid,[12] and that WDRM v4 merely shows *more* wildfire risk than WDRM v3.[13] However, PG&E's assumption is flawed; older versions of the WDRM incorporate less recent data, and thus do not represent an up-to-date view of PG&E's assets and environment. The asset data in the WDRM v3 is a snapshot from January 2022, whereas the asset data in WDRM v4 is current as of January 2023. While the WDRM v3 probability sub-model is trained on ignition events through 2020,[14] WDRM v4 is trained on ignition events through 2022.[15] Older models yet, such as WDRM v2, are even further outdated.[16] Due to reliance on these older data sets, prior versions of the WDRM do not account for any vegetation management, system hardening, asset repairs, replacements, or any other wildfire mitigation work that PG&E performed after the source dates of the model input and training data.

Due to the more recent information in PG&E's WDRM v4, Cal Advocates assumes that WDRM v4 represents the most complete and accurate understanding of the wildfire risk in PG&E's system that is currently available. However, prior versions of the WDRM will still influence PG&E's wildfire mitigation work through at least 2026.[17] Due to the dramatic shift in risk concentration between WDRM v4 and WDRM v3, PG&E and Energy Safety should re-evaluate what wildfire risk reduction work PG&E is performing. It is crucial to use up-to-date

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[12] PG&E's response to data request CalAdvocates-PGE-2025WMP-11, question 1.

[13] Conversations between Cal Advocates and PG&E on April 22 and 23, 2024.

[14] See Table PG&E-B.1.1-1 and Table PG&E-B.1.1-3 in PG&E's 2025 WMP Update at 8 and 10.

[15] See Table PG&E-B.1.1-1 and Table PG&E-B.1.1-3 in PG&E's 2025 WMP Update at 8 and 10.

[16] WDRM v2 has asset data from April 2019, ignition data through 2019, and the consequence sub-model uses a snapshot of fuel data from 2020. The consequence sub-models for WDRM v3 and v4 use a forecast fuel layer with predicted growth as of 2030. See Table PG&E-B.1.1-1 and Table PG&E-B.1.1-3 in PG&E's 2025 WMP Update at 8 and 10.

[17] For example, PG&E's system hardening workplan, provided in response to data request CalAdvocates-PGE-2025WMP-03, question 8, includes projects originally scoped by WDRM v2 and WDRM v3. A number of these projects are expected to complete construction in 2026.

information to ensure that work planned for 2025 and 2026 appropriately balances safety, reliability, and affordability for PG&E's ratepayers.[18]

2. The risk-ranked order of circuit segments under WDRM v4 is only moderately correlated to WDRM v3.

In addition to a flatter risk buydown curve, WDRM v4 redefines the circuit segments that are considered the highest risk. Figure 2 plots the risk ranking for circuit segments in the high fire-threat districts (HFTD) under both versions of the model.

Figure 2:

WDRM risk ranking of circuit segments in the HFTD[19]

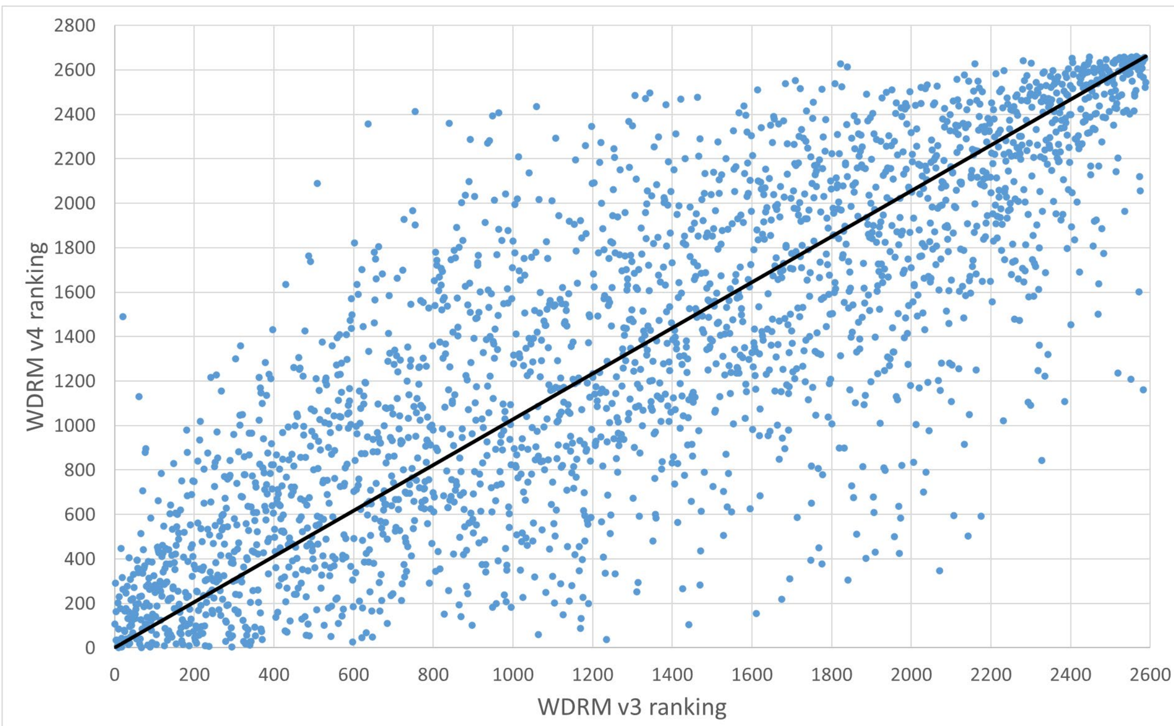

Figure 2 shows the risk rankings for PG&E's circuit segments in the HFTD under the current and prior versions of the WDRM. Lower rankings indicate high risk, while higher

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[18] Discussed in further detail in Sections IV.A and VI.A of these comments.

[19] This figure compares the risk-ordered ranking of circuit segments between PG&E's WDRM v3 and v4 using PG&E's responses to response to data requests CalAdvocates-PG&E-2022WMP-31, question 7 and CalAdvocates-PG&E-2025WMP-05, question 5. For simplicity, only circuit segments that appear in both models and have at least one circuit mile of overhead line in the HFTD are shown.

Note: a low risk ranking correlates to a high risk score. Thus, circuit segments closest to the vertical axis are considered high-risk under WDRM v3, while circuit segments closest to the horizontal axis are considered high-risk under WDRM v4.

rankings indicate comparatively lower risk. Although there is an undeniable correlation between the models, many circuit segments that were considered high risk under WDRM v3 are ranked lower under WDRM v4, and vice versa. This reversal has happened before, when PG&E updated its WDRM from version 1 to 2, and again from version 2 to 3.[20] These frequent changes of relative risk call into question the reliability of the risk model results, especially when used to plan undergrounding projects that take several years to execute.

3. The risk distribution and ranking under WDRM v4 may substantively affect PG&E's asset inspections and system hardening programs.

The differences between WDRM v3 and v4 may have significant implications for PG&E's asset inspections and system hardening programs. Under WDRM v3, the high concentration of wildfire risk in relatively few circuit-miles suggested that a narrow focus on the riskiest locations could rapidly buy down a large percentage of risk. In contrast, the flatter risk buydown curve of WDRM v4 may no longer support the same strategies.

In 2023, PG&E shifted its distribution asset inspection strategy to a risk-based approach: assets in higher-consequence locations would receive more frequent detailed inspections, while lower-consequence locations would receive less frequent inspections.[21] This was intended to enable PG&E to inspect the assets that represent most of the wildfire risk through a relatively small number of inspections.[22] PG&E termed this the "eyes on risk" percentage.[23] The flatter risk curve under WDRM v4 means that the same number of inspections would result in a lower "eyes-on-risk" percentage.[24]

Similarly, the flatter risk curve will result in a lower risk buydown for system hardening projects than previously estimated under prior risk models. It may also reduce the estimated cost-effectiveness of system hardening projects, which can cost ratepayers millions of dollars

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[20] See *Public Advocates Office Comments on the Draft Decision Approving PG&E's 2022 Wildfire Mitigation Plan Update*, October 26, 2022 at 2-5.

[21] Discussed in section 8.1.3.2.1 in PG&E's *2023-2025 Wildfire Mitigation Plan R4*, January 8, 2024 (2023-2025 WMP R4) at 481.

[22] PG&E uses the metric "Eyes-on-Risk" to measure the percentage of risk assessed through inspections. This is discussed in PG&E's 2023-2025 WMP R4 at 605.

[23] PG&E's 2023-2025 WMP R4 at 605.

[24] Asset inspection concerns are discussed in more detail in Section VI.A of these comments.

and take years to complete.[25] The re-ranking of circuit segments also means that the projects PG&E plans to complete through 2026 may not be targeted to reduce maximal risk.[26]

4. Prior to the start of the 2026-2028 WMP cycle, PG&E should quantitatively evaluate the effects that WDRM v4 will have on PG&E's programs.

Sophisticated risk models based on up-to-date information are an important planning tool. Such models can help a utility direct limited funds to mitigate the maximum amount of wildfire risk for the lowest cost to the ratepayer. To this end, Cal Advocates supports PG&E's efforts to refine its risk models.

However, the flatter risk buydown curve and the reordering of high-risk segments under WDRM v4 warrant a close look at the wildfire mitigation programs informed by the model. As PG&E transitions to the WDRM v4 to scope mitigation work, Energy Safety should work with PG&E and the Commission to study the implications of PG&E's new risk model. The study should, at a minimum:

- Evaluate whether the shift to WDRM v4 affects the estimated cost-effectiveness of PG&E's distribution system hardening program,[27]
- Evaluate whether the shift to WDRM v4 affects the estimated cost-effectiveness of PG&E's distribution asset inspections program,[28]
- Evaluate whether the shift to WDRM v4 affects the estimated cost-effectiveness of PG&E's distribution vegetation management program,[29]
- Identify necessary and reasonable changes to improve the cost-effectiveness of the above programs under WDRM v4, and

[25] System hardening concerns are discussed in more detail in Section IV.A of these comments.

[26] PG&E's system hardening workplan, provided in response to data request CalAdvocates-PGE-2025WMP-03, question 8, includes projects originally scoped by WDRM v2 and WDRM v3. A number of these projects are expected to complete construction in 2026.

[27] System hardening concerns are discussed in more detail in Section IV.A of these comments.

[28] Asset inspection concerns are discussed in more detail in Section VI.A of these comments.

[29] Cal Advocates did not identify any specific concerns with PG&E's vegetation management programs in its 2025 WMP Update. However, per PG&E's response to data request CalAdvocates-PGE-2025WMP-05, question 2, the WDRM v4 is intended to inform mitigation aimed at reducing vegetation related ignitions. As such, Cal Advocates includes vegetation management in this recommendation for the sake of completeness.

- Consider adjustments in each of the above programs (including changes in work scope, sequencing, or other changes) to ensure planned work appropriately balances safety, reliability, and affordability for PG&E's ratepayers.

PG&E should be required to publish the results of this study with its 2026-2028 Base WMP.

IV. SYSTEM HARDENING

A. PG&E's evolving risk model still does not support continued wide-scale undergrounding.

In 2022, Cal Advocates noted that PG&E had not justified the scale of its plan to underground 10,000 circuit miles of distribution, and that PG&E had not committed to target its undergrounding efforts to reduce the maximum amount of risk according to its risk models.[30] In 2023, PG&E had still not targeted the riskiest locations, and its planned scale of undergrounding (10,000 miles) lacked precision and justification.[31]

As of its 2025 WMP Update, PG&E has still not remediated these issues. It continues to fail to justify the 10,000-mile scope of its long-term undergrounding plans, and PG&E continues to not focus its undergrounding on the riskiest circuit segments. Considering PG&E's unjustified plans, Energy Safety should require the improvements described below.

1. PG&E has not justified its plan to underground 10,000 miles.

In 2023, PG&E stated that its plan to underground 10,000 miles (which equates to the removal of about 8,000 overhead miles[32]) would reduce approximately 70 percent of the risk in the HFTD.[33] An analysis of PG&E's distribution system using WDRM v3 partially supports this theory. Under that model, the riskiest 8,000 miles of PG&E's system carried approximately 70

[30] *Comments of the Public Advocate's Office on the 2022 Wildfire Mitigation Plan Updates of the Large Investor-Owned Utilities*, April 11, 2022 at 13-19.

[31] *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023 at 13-23.

[32] "On average, it takes 1.25 UG [underground] install miles to replace 1 OH [overhead] mile." PG&E's 2023-2025 WMP R4 at 1127.

[33] PG&E's response to data request CalAdvocates-PGE-2023WMP-09, question 10. Per this response, PG&E originally scoped the 10,000 miles based on WDRM v2. PG&E has not stated why it targeted 70 percent risk reduction, nor has it justified why 10,000 miles of undergrounding is the most reasonable mitigation to achieve 70 percent risk reduction.

percent of PG&E's total wildfire risk.[34] If PG&E were to move the entirety of those riskiest 8,000 overhead miles underground, it would remove approximately 69 percent of the wildfire risk from its system.[35] However, achieving this degree of risk mitigation requires a highly precise selection and scoping of projects that targets only the riskiest circuit segments.

PG&E has never planned its undergrounding work with such a laser focus on high-risk segments. PG&E does not plan to underground the entirety of the riskiest 8,000 miles. For example, in 2023 Cal Advocates observed that, according to WDRM v3, 79 circuit segments carried a cumulative five percent of the total wildfire risk in PG&E's system.[36] Despite this, PG&E had not scoped these circuit segments for either undergrounding or overhead hardening, instead opting to simply leave this risk in its system.[37] Given that PG&E's decision-making is not driven by risk, it is inevitable that PG&E's plan to underground 10,000 miles would ultimately eliminate *less* than 69 percent of the risk in its system (estimated using WDRM v3).

Furthermore, PG&E's newest risk model shows that risk is less concentrated than previously thought (see Figure 1). Under WDRM v4, if PG&E were to underground its riskiest 8,000 miles, it would eliminate only 49 percent of the total wildfire risk in its system.[38] It is not clear to what extent WDRM v4 represents a *redistribution* of risk as opposed to capturing *additional* risk that was not quantified in the previous version.[39] Regardless, the practical effect

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[34] Analysis of PG&E's WDRM v3, provided in response to data request CalAdvocates-PG&E-2022WMP-31, question 7. To estimate total risk carried by each circuit segments, Cal Advocates multiplied the system hardening composite risk score by the overhead circuit miles for each circuit segment. The riskiest 547 circuit segments are composed of 7,999 overhead miles and cumulatively carry 70.6 percent of the total wildfire risk.

[35] Per Table ACI-PG&E-23-05-3 in PG&E's 2025 WMP Update at 55, undergrounding is approximately 97.7 percent effective. 97.7% x 70.6% = 69.0%.

[36] *Public Advocates Office Opening Comments on Pacific Gas and Electric's Revised 2023-2025 Wildfire Mitigation Plan*, August 22, 2023 at 14-15.

[37] *Public Advocates Office Opening Comments on Pacific Gas and Electric's Revised 2023-2025 Wildfire Mitigation Plan*, August 22, 2023 at 14-15.

[38] Analysis of PG&E's WDRM v4, provided in response to data request CalAdvocates-PG&E-2025WMP-05, question 5. To estimate total risk carried by each circuit segments, Cal Advocates multiplied the system hardening composite risk score by the overhead circuit miles for each circuit segment. The riskiest 744 circuit segments are composed of 8,000 overhead miles and cumulatively carry 49.9 percent of the total wildfire risk.

Per Table ACI-PG&E-23-05-3 in PG&E's 2025 WMP Update at 55, undergrounding is approximately 97.7 percent effective. 97.7% x 49.9% = 48.8%.

[39] If WDRM v4 shows the same total risk as WDRM v3, but distributed over more miles, it would be a redistribution. If WDRM v4 includes new risk drivers, it would include more total risk. It is likely that

is that each circuit mile under WDRM v4 carries a smaller percentage of PG&E's total wildfire risk. Thus, achieving PG&E's stated goal of approximately 70 percent risk reduction would require either far more than 10,000 miles of undergrounding,[40] or a dramatic shift in strategy.

It is incumbent on PG&E to appropriately balance safety, reliability, and affordability.[41] A continued focus on widespread undergrounding would result in mitigation of less risk than previously believed, at great cost to ratepayers. This change in risk analysis supports a shift in focus: PG&E should place greater emphasis on covered conductor and operational mitigations,[42] which could reduce far more risk in less time and at less cost.[43]

For the same cost as 10,000 miles of undergrounding, PG&E could eliminate approximately 67 percent of its wildfire risk through covered conductor and operational mitigations (18 percentage points more risk reduction compared to undergrounding alone).[44] Or, examined another way, it would cost PG&E approximately $29.5 billion to eliminate 49 percent

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WDRM v4 represents both a redistribution of pre-existing risk, as well as additional risk.

[40] Intervenors have, on numerous occasions, voiced concerns over PG&E's rising rates and continued expected increases associated with wide-scale undergrounding. *See, e.g.*, *Opening Comments of the Utility Reform Network on Pacific Gas and Electric Company's 2023-2025 Wildfire Mitigation Plan*, May 26, 2023 at 5-6; *Mussey Grade Road Alliance Comments on 2023-2025 Wildfire Mitigation Plans of PG&E, SCE, and SDG&E*, May 26, 2023, at 79-81.

[41] "All charges demanded or received by any public utility…shall be just and reasonable" and " Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service…as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." Public Utilities Code Section 451.

[42] "Operational mitigations" here include tools such as fast-trip settings, downed-conductor detection, and newer technologies such as REFCL.

[43] "Overhead hardening can be completed at a rate of approximately three times that of undergrounding." PG&E's 2025 WMP Update at 56.

[44] In response to data request CalAdvocates-PGE-NonCase_02-20-2024, question 1, March 19, 2024, PG&E provided a list of system hardening projects completed in 2023 that included undergrounding. Cal Advocates filtered this list for projects that were 90% or greater undergrounding by length. This resulted in a list of projects that total 325 miles of undergrounding (for both "base system hardening" and "rebuild" purposes) at a total estimated cost of $958 million. This equates to an estimated average cost of $2.95 million per underground mile. 10,000 miles of undergrounding would therefore cost $29.5 billion.

Per PG&E's response to data request CalAdvocates-PGE-2025WMP-03, question 10, PG&E installed 144.8 miles of covered conductor in 2023 and spent $125 million on covered conductor. This results in an estimated cost per mile of $0.86 million per mile. For $29.5 billion, PG&E could install 34,300 miles of covered conductor.

Per analysis of PG&E's WDRM v4 (provided in response to CalAdvocates-PG&E-2025WMP-05, question 5), 4118 circuit segments carry 34,306 miles and 85.8% of the total risk. Per Table ACI-PG&E-23-05-3 in PG&E's 2025 WMP at 55, PG&E estimates that covered conductor in conjunction with operational mitigations is 78.2 percent effective. 78.2% x 85.8% = 67.1%

of its wildfire risk through its planned 10,000 miles of undergrounding, or *only $11.3 billion to eliminate the same amount of risk through covered conductor*.[45]

Despite the high cost of undergrounding and the lower risk reduction expected under WDRM v4, PG&E has no plans to reassess the scope of its undergrounding program in the near future.[46] PG&E instead plans to move forward with its arbitrary goal of undergrounding 8,000 overhead miles at great expense to ratepayers.

2. PG&E does not plan to use WDRM v4 to re-evaluate in-flight system hardening work.

PG&E's system hardening workplan for 2024-2026 includes projects selected under both WDRM v2 and WDRM v3.[47] As a result of the decision in its 2023-2026 general rate case (GRC), PG&E has reduced its 2024-2026 undergrounding targets by approximately 770 miles.[48] To achieve this, PG&E states that it primarily paused or canceled projects that were selected under WDRM v2,[49] which relies on data that is approximately four years out of date.[50]

Cal Advocates supports the removal of projects selected using older risk models. However, because PG&E has not yet scoped any undergrounding projects based on WDRM v4, the entirety of PG&E's system hardening workplan through 2026 still consists of projects selected by old risk models.[51] Among these are 234 projects that were selected using WDRM v2, but are not yet in construction.[52] These projects include over 143 miles of planned

[45] Per analysis of PG&E's WDRM v4 (provided in response to CalAdvocates-PG&E-2025WMP-05, question 5), 1236 circuit segments carry 13,106 miles and 63.0% of the total risk. Replacing these miles with covered conductor at $0.86 million per mile would cost $11.3 billion and eliminate 78.2% x 63.0% = 49.3% of PG&E's risk, the same as replacing 8,000 overhead miles with 10,000 underground miles.

[46] Conversations between Cal Advocates and PG&E on April 22 and 23, 2024.

[47] PG&E provided its current system hardening workplan in response to data request CalAdvocates-PGE-2025WMP-03, question 8.

[48] "a reduction in the number of undergrounding miles from 2,000 to 1,230 miles." PG&E's 2025 WMP Update at 22.

[49] Conversations between Cal Advocates and PG&E on April 22 and 23, 2024.

[50] Per Table PG&E-B.1.1-2 in PG&E's 2025 WMP Update at 8, WDRM v2 includes vegetation data through 2018, conductor asset data through 2020, and is trained on ignition events from 2015-2019.

[51] PG&E provided its current system hardening workplan in response to data request CalAdvocates-PGE-2025WMP-03, question 8.

[52] PG&E provided its current system hardening workplan in response to data request CalAdvocates-PGE-2025WMP-03, question 8. Cal Advocates filtered this for projects selected by WDRM v2, with status "Estimating," "Permitting/Dependency," and "Scoping/Scoped." This resulted in a list of 234 projects, with a total of 143.5 planned underground miles. The workplan includes a total of 1,353 planned

undergrounding, which is about 11 percent of PG&E's current workplan and will cost ratepayers approximately $423 million to complete.[53] PG&E's workplan includes an additional 812 miles ($2.4 billion worth) of projects selected using WDRM v3 that are not yet in construction.[54]

PG&E's workplan is only loosely targeted to the highest-risk locations. According to WDRM v4, the riskiest 8,000 miles (about 744 circuit segments) in PG&E's system carry about 50 percent of its cumulative wildfire risk.[55] However, as shown in Figure 3, while much of PG&E's system hardening is targeted within those 744 circuit segments (as shown by the cluster of projects toward the left of the chart), many miles are planned elsewhere, in far less risky locations (farther to the right on the X-axis). Figure 4 further shows that, even within the riskiest 744 circuit segments, PG&E's system hardening projects are distributed fairly evenly, rather than targeted to mitigate the maximum amount of risk.

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underground miles.

[53] As discussed in Section IV.A.1, undergrounding costs $2.95 million per underground mile. 143.5 miles x $2.95 million per mile = $423 million.

[54] PG&E provided its current system hardening workplan in response to data request CalAdvocates-PGE-2025WMP-03, question 8. Cal Advocates filtered this for projects selected by WDRM v3, with status "Estimating," "Permitting/Dependency," and "Scoping/Scoped." This resulted in a list of 341 projects, with a total of 812.2 planned underground miles. 812.2 miles x $2.95 million per mile = $2,396 million.

[55] Analysis of PG&E's WDRM v4, provided in response to data request CalAdvocates-PG&E-2025WMP-05, question 5. To estimate total risk carried by each circuit segments, Cal Advocates multiplied the system hardening composite risk score by the overhead circuit miles for each circuit segment. The riskiest 744 circuit segments are composed of 8,000 overhead miles and cumulatively carry 49.9 percent of the total wildfire risk.

Per Table ACI-PG&E-23-05-3 in PG&E's 2025 WMP Update at 55, undergrounding is approximately 97.7 percent effective. 97.7% x 49.9% = 48.8%.

Figure 3:

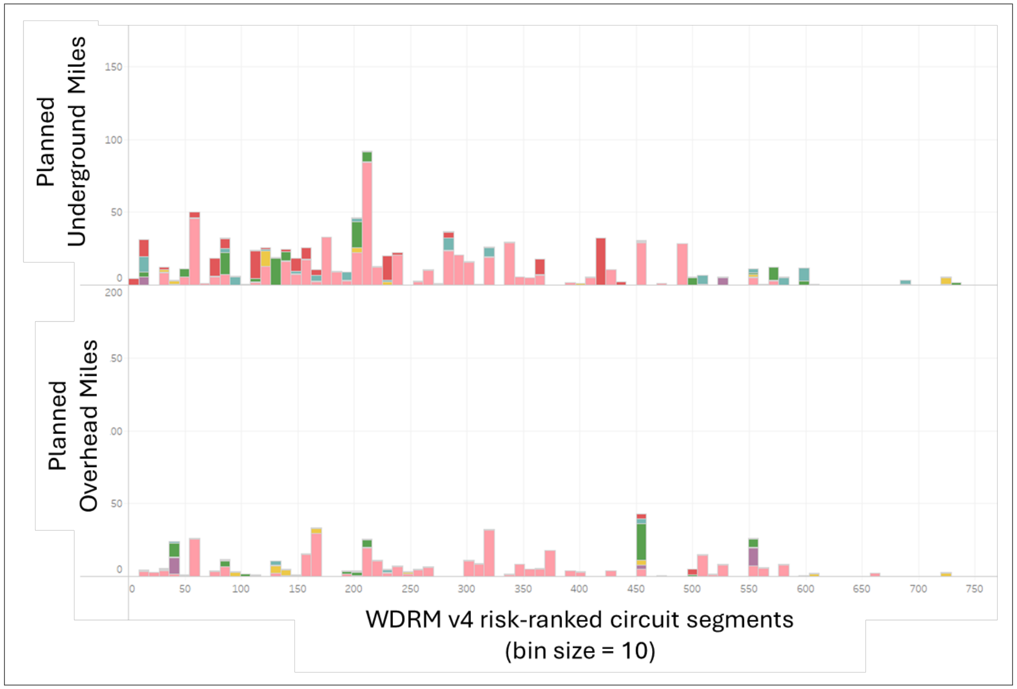
PG&E's planned underground and overhead system hardening mileage compared to circuit segments ranked by risk[56]

[56] This figure compares the planned system hardening mileage based on PG&E's 2024-2026 system hardening workplan (CalAdvocates-PGE-2025WMP-03, question 8) with the risk-ordered ranking of circuit segments under PG&E's v4 (using PG&E's response data request CalAdvocates-PG&E-2025WMP-05, question 5).

Figure 3 shows a breakdown of the overhead and underground miles in PG&E's system hardening workplan by circuit segment. The riskiest 744 circuit segments contain approximately 50 percent of PG&E's total wildfire risk per WDRM v4. While the majority of miles are targeted to that top 50 percent of risk, many projects are planned or in progress in less risky locations.

Figure 4:

PG&E's planned underground and overhead system hardening mileage compared to the circuit segments that carry 50% of PG&E's total risk[57]



[57] This figure includes the same data as Figure 3, but zooms in on the top 750 circuit segments, which contain approximately 8,000 circuit miles. These 750 circuit segments carry half of PG&E's total wildfire risk, estimated according to WDRM v4.

Figure 4 shows the same data as Figure 3, zoomed in to show just the miles targeted to the riskiest 750 circuit segments. The mileage is roughly evenly distributed throughout these segments, rather than narrowly targeted to mitigate the maximum amount of risk.

It is reasonable to expect that PG&E's in-flight system hardening projects would not perfectly align with the highest-risk locations according to its newest risk model. However, it would be unreasonable for PG&E to ignore the most current information available to it. With each project it greenlights for construction, PG&E makes a decision that affects public safety and ratepayer costs. PG&E should not simply move ahead with hundreds of miles (and billions of dollars) of undergrounding projects that are not yet in construction, without first validating whether those projects are still warranted under WDRM v4.

Indeed, in its decision on PG&E's 2022 WMP Update, Energy Safety directed PG&E to "describe and justify the threshold at which projects move forward even as risk prioritization evolves."[58] PG&E has consistently failed to establish such thresholds,[59] and has stated it has no plans to evaluate the cost-effectiveness of projects in its current workplan against the outputs of WDRM v4.[60]

In failing to re-evaluate in-flight projects under its most mature risk model, PG&E shows a lack of adaptability to new information and lack of commitment to efficient and rapid risk reduction. PG&E would instead justify its ongoing work with a sunk-cost fallacy[61] that will incur billions of dollars on behalf of ratepayers and achieve sub-optimal risk reduction.

3. Energy Safety should require PG&E to estimate the cost-effectiveness of system hardening projects in its current workplan that are not yet in construction.

To ensure that every ratepayer dollar PG&E spends reduces the maximum amount of wildfire risk, Energy Safety should issue a revision notice and direct PG&E to evaluate the

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[58] Energy Safety, *Final Decision on 2022 Wildfire Mitigation Plan Update Pacific Gas and Electric Company*, November 10, 2022 at 184-185.

[59] Discussed in *Public Advocates Office Opening Comments on Pacific Gas and Electric's Revised 2023-2025 Wildfire Mitigation Plan*, August 22, 2023 at 13-14.

[60] PG&E's response to data request CalAdvocates-PGE-2025WMP-08, question 5.

[61] The sunk-cost fallacy is the idea that one should stick to a choice because one has already spent money (or effort) on it, even though at present it would be better to choose a different option. The error is to focus on the money already spent, rather than the remaining costs required to achieve the goal. Since money already spent (sunk costs) cannot be recovered, a rational decision-maker should look at the future costs required to achieve future benefits. See, e.g., https://thedecisionlab.com/biases/the-sunk-cost-fallacy

expected risk reduction benefit for the projects in its system hardening workplan that are not yet in construction. This evaluation should include an estimated benefit in dollars and a cost-benefit ratio.[62]

For any projects where the cost-benefit ratio falls below one,[63] PG&E should either remove the project from its workplan, or replace it with overhead hardening, which is three times as fast to install[64] and less than one-fourth as costly[65] as undergrounding.

4. Energy Safety should require PG&E to estimate the actual cost-effectiveness of its past system hardening work based on its newest and most mature understanding of risk.

PG&E has updated its wildfire risk model every one to two years since 2019.[66] As shown in Figure 2, the newest version of PG&E's risk model substantially shifts the risk ranking of circuit segments. Cal Advocates has previously noted this to be true of all previous versions as well.[67] These frequent and substantial changes do not support a wildfire mitigation strategy that relies on slow and costly methods such as undergrounding. Undergrounding, by its nature, lags substantially behind risk assessment maturity. For example, in 2026 PG&E expects that it will still be completing undergrounding projects that are based on WDRM v2 – a model developed in 2021 with data inputs that end in 2018-2020.[68]

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[62] This should be done in accordance with the cost-benefit ratio adopted in D.22-12-027.

[63] A cost-benefit ratio compares the estimated lifetime benefit of a project to the estimated lifetime cost. A project with a ratio below one will cost ratepayers more than it benefits them.

[64] "Overhead hardening can be completed at a rate of approximately three times that of undergrounding." PG&E's 2025 WMP Update at 56.

[65] As discussed in Section IV.A.1 of these comments, undergrounding costs approximately $2.95 million per mile and covered conductor costs approximately $0.86 million per mile. Since a single undergrounding mile only removes, on average, 0.8 miles of overhead line, the equivalent cost per mile of overhead line removed is $3.7 million per mile, or 4.3 times the cost of a single mile of covered conductor.

[66] Per Table PG&E-B.1.1-1 in PG&E's 2025 WMP Update at 8, WDRM v1 was developed in 2019, WDRM v2 in 2021, WDRM v3 in 2022, and WDRM v4 in 2023.

[67] See *Public Advocates Office Comments on the Draft Decision Approving PG&E's 2022 Wildfire Mitigation Plan Update*, October 26, 2022, at 2-5.

[68] See Section IV.A.2 of these comments for greater detail. Per Table PG&E-B.1.1-2 in PG&E's 2025 WMP Update at 8, WDRM v2 includes vegetation data through 2018, conductor asset data through 2020, and is trained on ignition events from 2015-2019.

Although it is likely that prior versions of PG&E's risk model were not wholly invalid, it is irrefutable that a number of past undergrounding projects were performed in locations that are now understood to present only moderate or low risk.[69] However, PG&E has not yet performed an analysis of either its current workplan or its completed projects to estimate the cost-effectiveness of these projects under its current risk model.[70] Such an exercise would inform Energy Safety and the Commission as to whether PG&E's system hardening has consistently delivered a reasonable cost-benefit ratio or whether the frequent and substantial updates to its risk model have impeded cost-efficient risk mitigation.

Cal Advocates does not oppose PG&E's efforts to rapidly mature its risk model. But the continuously evolving understanding of risk calls for a faster and more nimble risk mitigation strategy that can be readily adapted to new versions of the risk model. Covered conductor is one such mitigation strategy. Being up to three times faster to install[71] and one-fourth as costly as[72] undergrounding, covered conductor can be planned and deployed more rapidly in response to changing risk models.

Energy Safety should require PG&E to report the estimated cost-benefit ratios of undergrounding projects it has completed since 2020, in its 2026-2028 Base WMP. If a substantial portion of past projects have had low cost-benefit ratios,[73] Energy Safety should

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[69] Cal Advocates analyzed PG&E's system hardening workplan (response to data request CalAdvocates-PGE-2025WMP-03, question 8) and compared the risk ranking of circuit segments under WDRM v2 (response to data request CalAdvocates-PGE-2021WMP-19, questions 1 and 2, March 15, 2021), WDRM v3 (response to data request CalAdvocates-PGE-2022WMP-31, question 7, September 8, 2022), and WDRM v4 (response to data request CalAdvocates-PGE-2025WMP-05, question 5).

Per this analysis, in 2023 PG&E performed undergrounding work in eight locations that were originally scoped as having high risk under WDRM v2 but had low risk under subsequent risk models. For these eight locations, the risk rankings under WDRM v2 ranged from 18 to 230; risk rankings under WDRM v3 ranged from 448 to 4,148; and risk rankings under WDRM v4 ranged from 1,174 to 8,713. Note that this analysis is meant to illustrate several examples and does not provide an exhaustive list.

[70] PG&E's response to data request CalAdvocates-PGE-2025WMP-08, question 5.

[71] "…overhead hardening can be completed at a rate of approximately three times that of undergrounding." PG&E's 2025 WMP Update at 56.

[72] As discussed in Section IV.A.3 of these comments, undergrounding costs approximately $2.95 million per mile and covered conductor costs approximately $0.86 million per mile. Since a single undergrounding mile only removes, on average, 0.8 miles of overhead line, the equivalent cost per mile of overhead line removed is $3.7 million per mile, or 4.3 times the cost of a single mile of covered conductor.

[73] The minimum reasonable cost-benefit ratio should be 1, where the estimated lifetime benefits of a project exactly balance with the estimated lifetime costs.

require PG&E to reassess the planned scope of its system hardening plans and consider incorporating more overhead hardening and operational mitigations to ensure the maximum feasible benefit to ratepayers.

5. Energy Safety should require PG&E to re-evaluate the scope of its long-term undergrounding plans.

PG&E's focus on undergrounding represents a fixation on a specific mitigation technique rather than the fundamental policy goals. As we explained in Section IV.A.1, PG&E could rapidly eliminate more risk at much lower cost through a targeted application of covered conductor and operational mitigations. Despite this, PG&E has refused to deviate from its preferred strategy, instead doubling down on a slow and expensive mitigation that will ultimately leave more risk in its system compared to other methods.

Thus, Energy Safety should require PG&E to analyze alternative strategies that reasonably balance safety, reliability, and affordability.[74] PG&E should present these alternative strategies for review in its 2026-2028 Base WMP. At a minimum, PG&E's alternatives should include a strategy that focuses on rapid deployment of covered conductor in conjunction with operational mitigations (approximately what SCE terms "CC++"[75]). A second alternative strategy should involve system hardening with both undergrounding and covered conductor (rather than all one or the other), in which the preferred mitigation for each specific location would depend on the risk level, terrain, and tree cover.[76] Another alternative should emphasize widespread operational mitigations (including rapid earth-fault current limiters), aggressive asset inspections in high-risk areas, accelerated resolution of overdue asset repairs, and a moderate amount of system hardening (which could be termed a "robust O&M" approach).[77]

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[74] While PG&E may have a preferred option, it should present genuine, viable alternatives with a good-faith evaluation of the merits of each.

[75] SCE, 2023-2025 Wildfire Mitigation Plan R2, April 2, 2024 at 206.

[76] Undergrounding would likely be preferable for extremely risky locations and places with many potential strike trees. Covered conductor would typically be preferable in places with difficult terrain, rocky ground, or little forest cover.

[77] For example, a moderate amount of system hardening could entail about 500 miles of covered conductor deployment per year, which would result in hardening 20 percent of distribution miles in the HFTD over a decade.

Energy Safety should thoroughly evaluate these alternate strategies in 2025, with public input, and should direct PG&E to select the most reasonable strategy to appropriately balance safety, reliability, and affordability.

V. NEW TECHNOLOGIES

A. PG&E has made no meaningful progress on REFCL since 2021.

1. REFCL is a promising technology that complements other mitigations.

Rapid earth-fault current limiter (REFCL) technology has the potential to reduce the ignition probability for single-line-to-ground faults by 90 percent. This could serve as an effective companion technology to PG&E's enhanced powerline safety settings (EPSS).[78] REFCL could be applied to 133 PG&E substations that collectively serve approximately half of PG&E's HFTD.[79]

PG&E estimates that a single REFCL installation could cost as much as $15 million.[80] Based on this estimate, it would cost approximately $2 billion to install REFCL at the 133 substations. However, this is much less than the cost of system hardening for the equivalent mileage, because those substations support thousands of circuit miles.[81]

REFCL technology in combination with Enhanced Powerline Safety Settings (EPSS) and Covered Conductor (CC) could further reduce ignition risk across half of PG&E's HFTD for much less than either undergrounding or covered conductor.[82]

2. PG&E shows little progress in testing or deploying REFCL technology.

Progress on PG&E's evaluation of REFCL has been stalled since 2021. PG&E initiated its REFCL demonstration project in 2018 and in 2020 finished construction of the REFCL pilot

[78] PG&E's response to data request SPD_001, question 3, March 9, 2023.

[79] In response to data request CalAdvocates-PGE-2025WMP-07, question 6, PG&E provided a list of 133 substations where REFCL could be applied. Collectively, these 133 substations serve a total of 13,000 miles in the HFTD. The same spreadsheet shows a total HFTD mileage of approximately 25,000 miles.

[80] Response to CalAdvocates-PGE-2023WMP-11, question 8, April 10, 2023.

[81] As discussed in Section IV.A.3 of these comments, covered conductor costs approximately $0.86 million per mile. Hardening the 13,000 miles served by the 133 substations would cost over $11 billion (or significantly more with undergrounding).

[82] See a comparative discussion of system hardening costs in Section IV.A.1 of these comments.

at the Calistoga substation.[83] PG&E then began testing the system in 2021 with initial positive test results, but the project stalled due to failure of the substation equipment in 2021 and 2022 and difficulty obtaining replacement equipment.[84] Since then, there has been little development in PG&E's REFCL pilot. In 2023, PG&E allocated no funds for REFCL, and stated it had not done any design or capital work to expand REFCL beyond its single pilot substation.[85]

PG&E now states that it anticipates receiving results of the REFCL pilot by the end of 2024.[86] It is therefore unlikely that PG&E will expand REFCL beyond Calistoga until 2026 or later.[87]

3. Energy Safety should require PG&E to file quarterly updates on its REFCL pilot and evaluate further substations for REFCL deployment.

Due to the promising nature of REFCL, Energy Safety should require PG&E to file quarterly updates on its REFCL pilot until the pilot has concluded. This would provide better insight into PG&E's progress and keep Energy Safety and intervenors aware of any complications that may arise.

Additionally, Energy Safety should require PG&E to report the results of the REFCL pilot in its 2026-2028 Base WMP and examine the appropriate next steps. In its 2026-2028 WMP, PG&E should at a minimum:

- Describe its immediate and long-term plans for REFCL implementation;
- Evaluate complementarities with other mitigation measures, and present any available field or lab evidence regarding the efficacy of REFCL in combination with other mitigations; and
- Either present a plan to expand REFCL to a subset of the 133 substations that could support it, or demonstrate how doing so is not in the best interests of Californians.

[83] PG&E, *2023-2025 Wildfire Mitigation Plan R5*, April 2, 2024 (2023-2025 WMP R5) at 284.

[84] PG&E's response to data request CalAdvocates-PGE-2025WMP-07, question 13.

[85] PG&E's response to data request CalAdvocates-PGE-2023WMP-11, question 3, April 10, 2023.

[86] PG&E's response to data request CalAdvocates-PGE-2025WMP-07, question 13.

[87] PG&E's 2025 WMP Update does not indicate any plans to expand its REFCL program in 2025.

PG&E has not done any work to expand its REFCL program[88] despite its promising effectiveness, low cost compared to other types of system hardening, and potential complementary nature with EPSS. The measures outlined above will ensure that Energy Safety and stakeholders will have sufficient information to judge whether PG&E's position is well-supported by evidence, or whether this technology would provide significant safety benefits to Californians.

VI. ASSET INSPECTION AND MAINTENANCE

A. PG&E's method for setting the frequency of detailed inspections is not reasonable.

In 2023, PG&E shifted its distribution asset inspection strategy to a risk-based approach that uses geographical groupings for operational efficiency.[89] Under this framework, assets are placed geographically on plat maps, which are the geographic units historically used by inspectors.[90] PG&E's strategy is to estimate the risk of these geographical areas and prioritize asset inspections in locations where estimated wildfire consequence is highest. Assets in higher-consequence plat maps are inspected annually, while lower-consequence plat maps are inspected every two or three years.[91]

1. PG&E's method of assigning inspection frequencies is arbitrary and not supported by a risk analysis.

Cal Advocates generally supports risk-based inspection prioritization, but has concerns with PG&E's specific methodology. PG&E discretizes its plat maps into three tiers: extreme and severe consequence areas (inspected annually), high risk areas (inspected every two years), and medium and low risk areas (inspected every three years).[92] The basis for this discretization is shown in Figure 5.

[88] PG&E's response to data request CalAdvocates-PGE-2023WMP-11, question 3, April 10, 2023.

[89] PG&E's 2023-2025 WMP R5 at 487.

[90] PG&E's 2023-2025 WMP R5 at 487.

[91] Discussed in section 8.1.3.2.1 in PG&E's 2023-2025 WMP R4 at 481.

[92] Discussed in section 8.1.3.2.1 in PG&E's 2023-2025 WMP R4 at 481.

Figure 5:
Detailed distribution asset inspection frequencies[93]

consequence_percent_rank	Wildfire consequence_rank	Inspection_cycle_year
> 0.99	extreme	1
≤0.99 and >0.98	severe	1
≤0.98 and >0.90	high	2
≤0.90 and >0.80	medium	3
≤0.80	low	3

Figure 5 shows that PG&E uses the consequence *rank* of the plat maps to place the plat maps into percentile categories.[94] Each category is then assigned an inspection frequency. Assuming the total number of plat maps is unchanging, this will always result in the same number of plat maps being assigned to each inspection frequency.

Figure 5 shows that PG&E will conduct detailed inspections annually on just two percent of the plat maps – or approximately two percent of its assets in the HFTD and high fire-risk areas (HFRA).[95] For eight percent of the plat maps, PG&E will perform detailed inspections biennially. Meanwhile, the remaining 90 percent of the HFTD will be inspected only once every three years.

As discussed in Section III.A.1 of these comments, the wildfire risk in PG&E's system is less concentrated under WDRM v4 compared to WDRM v3. As a result, if PG&E maintains a constant number of plat maps at each inspection frequency, it will reach a smaller percentage of

[93] Table 5 in Utility Procedure TD-8123P-201 at 7, provided in response to data request CalAdvocates-PGE-2025WMP-07, question 15.

[94] "Consequence_percent_rank" is defined as "the percentage of the total plat maps whose consequence scores are lower than that value." Utility Procedure TD-8123P-201 at 7, provided in response to data request CalAdvocates-PGE-2025WMP-07, question 15.

[95] Per PG&E's response to data request CalAdvocates-PGE-2025WMP-07, question 15, the "extreme and severe" category includes 11,464 structures, out of a total of 658,651 structures, or about 1.74 percent.

total risk than it previously thought. PG&E has not yet indicated any intention to revise its inspection frequencies based on the new information in its latest risk model.[96]

Furthermore, the hard and arbitrary numerical boundaries between inspection tiers may produce undesirable results. PG&E's procedure can assign an annual inspection frequency to one plat map, but may push a plat map with slightly lower but very similar risk to a two-year cycle. Likewise, at the 90th percentile boundary, a plat map will be reduced to a three-year cycle even though it may have similar characteristics to the plat map ranked just above it.
PG&E has not provided an analysis of the ranges or variances of estimated wildfire consequence for the plat maps in each of the buckets. It would be more reasonable for PG&E to analyze the consequence distribution in its territory and discretize its plat maps according to natural breaks in the consequence distribution.

2. The incremental cost of increased inspection frequencies is low.

PG&E estimates that increasing the inspection frequency for all high and medium consequence plat maps would raise its annual inspection costs by less than $8 million.[97] This would be approximately a 0.1 percent increase in PG&E's total WMP costs,[98] or approximately a 10 percent increase in the cost of PG&E's asset inspections in the HFTD.[99] PG&E's cost estimates may not be exact but they are useful for placing the cost of inspections in perspective.

[96] PG&E's response to data request CalAdvocates-PGE-2025WMP-07, question 16.

[97] Per PG&E's 2025 WMP Update at 76, inspecting all high consequence assets annually by ground would cost approximately $4.3 million annually, and inspecting all medium consequence assets every two years by ground would cost approximately $1.7 million annually, for a total annual increase of $6 million. Per PG&E's response to data request CalAdvocates-PGE-2025WMP-07, question 17, inspecting all high consequence assets annually by air would cost approximately $5.5 million annually, and inspecting all medium consequence assets every two years by air would cost approximately $2.3 million annually, for a total annual increase of $7.8 million.

[98] Per Table 4-1 in PG&E's 2023-2025 WMP R5 at 73, PG&E forecasts its WMP spending to be $6.2 billion 2024 and $6.4 billion in 2025.

[99] Per Table 11 in PG&E's quarterly data report for the fourth quarter of 2024, revised and resubmitted on April 16, 2024, PG&E projects operational expenses of $79.6 million in its HFTD for asset inspections.

While it is difficult to evaluate the incremental benefit of more frequent inspections,[100] the incremental cost is relatively low. Due to the increasing age of PG&E's assets,[101] increasing the frequency of inspections may be a prudent measure that would come at a relatively low cost, compared to other wildfire mitigation measures.

3. Energy Safety should require PG&E to re-evaluate its methodology for determining detailed inspection frequencies.

Given the small incremental cost of increasing inspection frequencies, Energy Safety should require PG&E to re-evaluate its methodology for discretizing plat maps into consequence tiers. Energy Safety should direct PG&E to, at a minimum, analyze the consequence distribution of its plat maps and evaluate the distribution for natural breaks in consequence, rather than rely on a strict percentage that maintains a constant number of plat maps in each consequence tier.

Energy Safety should also direct PG&E to conduct an analysis of the benefits and costs of adjusting its asset inspection frequencies. PG&E should examine several options, such as:

- Moving the "high" consequence category to an annual inspection cycle – in other words, annual inspections for all plat maps above the 90th percentile;
- Extending the "severe" consequence category down to the 95th percentile; and
- Moving the "medium" consequence category to a two-year inspection cycle.

PG&E should present the results of these analyses in its 2026-2028 Base WMP and either adjust its inspection program for 2026, or demonstrate that its current method reasonably assigns inspection frequencies based on relative risk.

B. PG&E made several changes to its inspections programs that were not reported in the 2025 WMP Update.

Since the submission of PG&E's 2023-2025 Base WMP, PG&E has introduced modifications to its asset inspection strategy. These modifications include but are not limited to,

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[100] "PG&E does not quantify the estimated benefit, in dollars, of inspecting high or medium consequence assets annually. The main benefit of additional inspections is identifying additional maintenance needs, but PG&E does not have a standardized approach to calculating a dollar benefit associated with identifying additional notifications, as PG&E treats inspections as a foundational program that supports PG&E's maintenance program." PG&E's response to data request CalAdvocates-PGE-2025WMP-07, question 17.

[101] Discussed in Filsinger Energy Partners, *PG&E Independent Safety Monitor Status Report*, April 3, 2023 at 13-15, and *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023, at 38-40.

the introduction of a new X-tag classification,[102] which modifies the maximum completion time for B-tags from 90 days to 180 days,[103] and simplifies the inspector checklist from over 100 items to 21 failure-specific inspection questions.[104] Notably, these modifications were omitted from PG&E's 2025 WMP Update; Cal Advocates learned of the changes through the PG&E Independent Safety Monitor's March 2024 report.[105]

According to PG&E, these changes will have the practical effect of reducing the number of lower-priority E and F tags generated.[106] This may result in the appearance of progress by reducing PG&E's backlog of open notifications, but it can also result in PG&E's failure to identify lesser issues that are still safety concerns. As noted in Cal Advocates' comments on PG&E's past WMP submissions,[107] PG&E has had a number of ignitions within HFTDs that have been linked to open maintenance notifications.

1. Energy Safety should require PG&E to report the estimated and actual effects of its changes to inspection strategy.

PG&E's latest modifications to its inspection strategy should be reviewed and analyzed to ensure they not only benefit PG&E's inspection programs, but also avoid undesirable side effects. For example, changes to the inspection checklist could introduce risk by increasing maintenance remediation times and identifying fewer lower-priority tags. However, because

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[102] X tags are classified as a level 2 condition and require remediation within 7 days. This classification prioritizes notifications that require urgent attention but do not require an inspector to stay onsite nor require resources to be pulled away from a job to mitigate the hazard immediately.

Filsinger Energy Partners, *PG&E Independent Safety Monitor Status Update Report*, March 29, 2024 (2024 ISM report) at 20.

[103] 180 days is the GO 95 rule 18 maximum for HFTD Tier 3 level 2 issues. GO 95, Rule 18(B)(1)(a)(ii) & Appendix I at I-3.

[104] 2024 ISM Report at 24-25.

[105] *PG&E Independent Safety Monitor Status Update Report*, March 29, 2024 (2024 ISM report).

[106] "During PG&E committee meetings to approve these new checklists, the ISM observed that questions were raised from members regarding possible inspection misses resulting from not listing every failure mode for every component, and not asking inspectors to positively confirm that components are okay." 2024 ISM report at 24.

[107] *Comments of the Public Advocate's Office on General Issues in the 2022 Wildfire Mitigation Plan Updates of the Large Investor-Owned Utilities*, April 11, 2022 at 8; *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023 at 32.

these changes were not detailed in PG&E's 2025 WMP Update, neither Energy Safety nor intervenors have had the opportunity to evaluate such changes.

Energy Safety should issue a revision notice and direct PG&E to fully describe all changes it has made to its inspection strategy since its 2023-2025 Base WMP. In addition, Energy Safety should require PG&E to include the following in its revision:

- Justification for the reprioritization of B tags, to demonstrate that it will not increase ignition risk.
- An estimate of the effect of its reduced inspection checklist on findings, to demonstrate that the change will not increase ignition risk.

Additionally, Energy Safety should require PG&E to report actual inspection results using the new process. Each quarter in 2024 and 2025, PG&E should report:

- How many of each level of tag it has created from each inspection type;
- How many of each level of tag it has closed;
- The number of inspections of each type performed (to normalize tags generated per inspection); and
- The mean and median remediation time for level of tag.

PG&E should provide comparable quarterly data for 2022-2023 using its previous inspection procedures.

C. PG&E's quality assurance and quality control results continue to raise concerns.

1. PG&E's data on quality control of asset inspections is not reliable.

In 2021 and 2022, PG&E's asset inspections suffered from poor quality, with its quality control (QC) pass rates as low as 67 percent.[108] In 2023, PG&E appears to have improved this dramatically, reporting a QC pass rate of 99.6 percent for transmission inspections and 86.1 percent for distribution inspections.[109]

However, an analysis of the underlying data suggests the actual pass rate may be lower than reported. As shown in Table 1 and Table 2, the raw data suggests that PG&E performed

[108] See discussion in *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023 at 23-25.

[109] Per Table 1 in PG&E's quarterly data report for the fourth quarter of 2024, revised and resubmitted on April 16, 2024.

more quality reviews than were reported, and that a lower percentage of those reviews passed QC.

Table 1 **Quality control of PG&E's distribution detailed ground inspections (2023)**						
	Desktop QC			Field QC		
	Number of inspections reviewed by QC	Number of inspections that failed QC review	QC pass rate	Number of inspections reviewed by QC	Number of inspections that failed QC review	QC pass rate
PG&E's reporting[110]	186,140	11,790	93.7%	38,880	5,401	86.1%
Cal Advocates' analysis[111]	194,518	18,838	90.3%	42,271	9,077	78.5%

Table 2 **Quality control of PG&E's transmission detailed ground inspections (2023)**						
	Desktop QC			Field QC		
	Number of inspections reviewed by QC	Number of inspections that failed QC review	QC pass rate	Number of inspections reviewed by QC	Number of inspections that failed QC review	QC pass rate
PG&E's reporting[112]	20,988	177	99.2%	2,006	9	99.6%
Cal Advocates' analysis[113]	28,087	809	97.1%	2,474	156	93.7%

[110] In response to data request CalAdvocates-PGE-2025WMP-03, question 6, PG&E provided a breakdown of QC results by inspection type and QC type. Table 1 in PG&E's quarterly data report for the fourth quarter of 2024 appears to report the results for field QC of detailed ground inspections.

[111] In response to data request CalAdvocates-PGE-2025WMP-03, question 1, attachments 5 and 6, PG&E provided raw data for distribution field and desktop QC. This analysis is based on the number of inspections where QC identified a "Compelling abnormal condition missed during inspection." Per PG&E's response to CalAdvocates-PGE-2022WMP-08, question 4, February 25, 2022, a failed QC review is defined as "a compelling abnormal condition was miss-identified by the inspector, resulting in an incorrectly updated EC/LC notification, or failure to create an EC/LC notification."

[112] In response to data request CalAdvocates-PGE-2025WMP-03, question 6, PG&E provided a breakdown of QC results by inspection type and QC type. Table 1 in PG&E's quarterly data report for the fourth quarter of 2024 appears to report the results for field QC of detailed ground inspections.

[113] In response to data request CalAdvocates-PGE-2025WMP-03, question 1, attachments 7 and 8, PG&E provided raw data for distribution field and desktop QC. This analysis is based on the number of

In addition to the discrepancies noted in Table 1 and Table 2, PG&E's quality assurance (QA) data shows a number of data quality issues. For example, the field for inspectors to mark the internal priority level of a finding appears to not have been limited to a drop-down menu (e.g., limited to PG&E's internal priorities of A, B, E, F, and others).[114] As a result, the list of finding priorities includes numerous different text strings that do not clearly indicate a finding or discrepancy,[115] including several that consist of full sentences including first-person observations, presumably entered by the initial inspector.[116] These discrepancies indicate that the field inspection data used to perform QA/QC is poorly standardized, limiting its potential to inform improvements and complicating data analysis.

2. Energy Safety should require PG&E to address the data quality issues in its asset inspections QA/QC.

Energy Safety should issue a revision notice regarding asset inspection QC. Energy Safety should require PG&E to provide an explanation for the discrepancy in QC pass rates noted in Table 1 and Table 2 and provide a clear explanation for how it calculates QC pass rates.

In addition, Energy Safety should direct PG&E to standardize its distribution and transmission inspection data collection fields and field types. Wherever possible, fields should be reduced to a drop-down menu, radio button, or checkboxes (or to any form more limiting than a free-response text box). PG&E should provide a progress update on this standardization in its 2026-2028 Base WMP.

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inspections where QC identified a "Compelling abnormal condition missed during inspection." Per PG&E's response to CalAdvocates-PGE-2022WMP-08, question 4, February 25, 2022, a failed QC review is defined as "a compelling abnormal condition was miss-identified by the inspector, resulting in an incorrectly updated EC/LC notification, or failure to create an EC/LC notification."

[114] PG&E's response to data request CalAdvocates-PGE-2025WMP-03, question 1, attachment 1, column P.

[115] PG&E's response to data request CalAdvocates-PGE-2025WMP-03, question 1, attachment 1, column P. See, e.g., row 2496, "Best total photo I could get because of trees and third party already exist."

[116] PG&E's response to data request CalAdvocates-PGE-2025WMP-03, question 1, attachment 1, column P. See, e.g., row 43, "No ecs *(sic)* and that's the best pictures I could get rough terrain and poison oak everywhere," which indicates no finding and does not flag for re-inspection.

3. Energy Safety should develop QA/QC standards.

In 2024, Energy Safety should work with industry experts and interested stakeholders to develop guidance on QA/QC data collection and standardization procedures. It may be valuable to convene a workshop or working group on best practices for QA/QC procedures.

In its forthcoming guidelines for the 2026-2028 Base WMPs, Energy Safety should set forth a process to identify the independent variables that utilities must track related to QA and QC, and establish a method or equation to standardize the calculation of QC pass rates across all utilities.

D. PG&E's intrusive pole inspections continue to suffer from poor quality.

PG&E's 2025 WMP Update discusses intrusive pole inspections as a reliable tool in its overall asset maintenance program to provide better information than a visual inspection alone.[117] PG&E does not report any specific roadblocks or updates to its Intrusive Pole Inspection program.[118]

1. PG&E's intrusive pole inspections exhibited poor results in 2023.

In 2023, PG&E's intrusive pole inspections generated extremely low QC pass rates. The QC pass rate was less than 50 percent in all cases – regardless of whether the inspection was of transmission or distribution assets or whether review was conducted in the field or by desktop.[119] A breakdown by asset type and QC review type is shown in Table 3 below.

[117] PG&E's 2023-2025 WMP R5 at 271 ("These [Intrusive Pole] inspections can be effective in identifying wood poles that need to be replaced before a pole failure, which could result in an ignition event."), and at 562 ("[A] routine visual inspection of a pole can identify a deteriorated pole but may not provide enough information about the extent of the damage or condition of the pole. To get better information, we will conduct a pole test and treat intrusive inspection that will enable us to make a more informed decision…").

[118] PG&E's 2023-2025 WMP R5 at 481.

[119] PG&E's response to CalAdvocates-PGE-2025WMP-03, question 6. Transmission intrusive inspections failed 108 of 133 (81%) desktop reviews and 134 of 149 (89.9%) field reviews, and Distribution intrusive inspections failed 1672 of 2820 (59.3%) desktop reviews and 1021 of 1491 (68.5%) field reviews.

Table 3 **QC pass rates: PG&E's intrusive pole inspections (2023)**[120]			
	Number of inspections reviewed by QC	Number of inspections that failed QC review	QC pass rate
Transmission: Desktop Review	133	108	18.8%
Transmission: Field Review	149	134	10.1%
Distribution: Desktop Review	2820	1672	40.7%
Distribution: Field Review	1491	1021	31.5%

Table 3 shows that an extremely high number of inspections failed QC reviews. Transmission inspections that were reviewed passed the QC review between 10 and 19 percent of the time. Distribution inspections performed somewhat better, passing between 31 and 41 percent of the time. PG&E's QC failure rates of 60 to 90 percent are unacceptable, because they imply that intrusive inspections frequently overlook or misidentify important problems.

According to PG&E's data request response, these numbers do not necessarily represent failed inspections; an inspection can fail QC review if an inspector does not accurately identify a checklist attribute.[121] However, the high failure rate in QC review is concerning, and does not allow for an informative evaluation of the effectiveness of PG&E's intrusive pole inspections. As Cal Advocates showed in 2023, PG&E's intrusive pole inspections program has experienced numerous failures since 2020.[122] A robust QC program is necessary to avert further such failures.

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[120] PG&E's response to CalAdvocates-PGE-2025WMP-03, question 6.

[121] PG&E's response to CalAdvocates-PGE-2025WMP-10, question 9.

[122] See discussion in *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023 at 29.

2. Energy Safety should require PG&E to improve its intrusive inspections program.

Energy Safety should issue a revision notice regarding intrusive pole inspections. Energy Safety should require PG&E to investigate and explain its high failure rate for quality control specific to intrusive inspections. The explanation should address, at a minimum, its process for conducting the initial intrusive inspection and for auditing the inspection.

In its revised WMP, PG&E should offer proposals both to improve its initial intrusive inspections (for example, improving inspector training or the inspection checklist) and to strengthen quality control. PG&E should define and begin reporting an updated quality control pass rate that indicates the percentage of intrusive inspections in which "a compelling abnormal condition" was missed or misidentified by the original inspector.[123] PG&E should report these pass rates retroactively for 2023 and begin reporting quarterly henceforth.

E. PG&E does not perform quality control in a timely manner.

1. PG&E's procedures allow lengthy delays before performing quality control.

PG&E's responses to discovery indicate a fundamental problem with the design of its QA/QC programs: there is often a substantial delay of 90 or more days between an inspection and the associated QC/QA process.[124]

In 2023, PG&E performed 75,133 work verification inspections following routine vegetation management work on distribution lines.[125] According to PG&E, 86 percent of these work verification inspections were conducted more than 90 days after the original vegetation management work.[126] Similarly, in 21 percent of detailed transmission asset inspections, field QC was performed more than 90 days after the original asset inspection.[127]

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[123] Per PG&E's response to CalAdvocates-PGE-2022WMP-08, question 4, February 25, 2022, a failed QC review is defined as "a compelling abnormal condition was miss-identified by the inspector *(sic)*, resulting in an incorrectly updated EC/LC notification, or failure to create an EC/LC notification."

[124] "Work verification" is PG&E's term for quality control of vegetation management inspections, and "quality verification" is equivalent to quality assurance for vegetation management work. See, e.g., PG&E's 2023-2025 WMP R5 at 615 and 701.

[125] PG&E's response to data request CalAdvocates-PGE-2025WMP-03, question 1, attachment 4.

[126] PG&E's response to data request CalAdvocates-PGE-2025WMP-03, question 1, attachment 4. 64,617 inspections had more than 90 days between the "VMI [vegetation management inspection] Date" and the "WV Date."

[127] PG&E's response to data request CalAdvocates-PGE-2025WMP-03, question 1, attachment 7. 524

A long delay between the initial inspection and QC review can potentially leave risk in the system if an unidentified issue goes unlogged and unremediated. Moreover, it makes it difficult to verify if the assets or vegetation were in the same condition at the times of the original visit and the QC review. Cal Advocates' comments on SDG&E's 2025 WMP Update explained that SDG&E's QC programs suffer from a similar problem and that SDG&E has assumed that its QC audits are not sufficiently valid to construct a pass rate.[128]

PG&E does not appear to have a standard for the maximum allowable time between an asset inspection and a QC review.[129] For vegetation management, PG&E requires only that a work verification review occur prior to the next routine vegetation management inspection,[130] or within approximately six months.[131] Given that vegetation will grow, PG&E's approach raises concerns because the longer the gap between the two visits is, the less reliable the QC review will be.

2. Energy Safety should require PG&E to collaborate with peer utilities to determine an appropriate QC timeline.

Energy Safety should require PG&E to collaborate with SCE and SDG&E to determine an appropriate time limit between the initial work and the associated QC review, for all relevant work types (asset inspections, vegetation inspections, vegetation trimming work, and so forth). The large utilities should report on the results of this collaboration in their 2026-2028 Base WMPs.

VII. AREAS FOR CONTINUED IMPROVEMENT

A. PG&E did not comply with ACI PG&E-23-05.

In its Final Decision on PG&E's 2023-2025 WMP, Energy Safety directed PG&E to improve its effectiveness evaluations and location-specific decision-making for its system

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QC field reviews (out of 2474 total) had more than 90 days between "Inspection Date" and "QC Completion Date."

[128] SDG&E's 2025 WMP Update at 100. See also *Comments of the Public Advocates Office on SDG&E's 2025 Wildfire Mitigation Plan Update*, May 7, 2024, at sections V.A and V.A.3.

[129] PG&E's response to data request CalAdvocates-PGE-2025WMP-10, question 4. PG&E's response to the question "Does PG&E have a standard for the maximum amount of time that is allowable between an inspection and the QC date?" referred only to the time between a QC review and QA review.

[130] PG&E's response to data request CalAdvocates-PGE-2025WMP-10, question 5.

[131] Per PG&E's 2023-2025 WMP R5 at 675, PG&E performs a second VM patrol approximately six months offset from the primary patrol.

hardening efforts.[132] Energy Safety required PG&E to provide more accurate effectiveness estimates (considering observed in-field effectiveness and time value of risk), to provide details on projects driven by reliability risk as opposed to wildfire risk, and other specific actions outlined in Area of Continuous Improvement (ACI) PG&E-23-05.[133] PG&E's 2025 WMP Update does not provide the required elements and therefore does not comply with ACI PG&E-23-05.

1. PG&E's flawed estimates for mitigation effectiveness are not supported by field data.

Energy Safety directed PG&E to "provide more accurate effectiveness estimates for its hardening efforts when calculating cost effectiveness scores," including "justification based on observed in-field effectiveness."[134] PG&E's effectiveness estimates are flawed in a number of ways.

First, PG&E does not follow observed, empirical data on effectiveness. PG&E bases its effectiveness calculations of mitigations on internal Subject Matter Expert judgment rather than observed effectiveness.[135] For undergrounding, PG&E continues to use an effectiveness rating of 99 percent for complete undergrounding,[136] despite Energy Safety's observation that PG&E's actual data show an effectiveness closer to 95 or 96 percent.[137] PG&E similarly skews the effectiveness for covered conductor, using an effectiveness estimate of 66.4 percent, despite Energy Safety's observation that it is likely greater than 70 percent effective.[138] Field data from

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[132] Energy Safety, *Decision on 2023-2025 Wildfire Mitigation Plan Pacific Gas and Electric Company*, December 29, 2023 (Final Decision on PG&E's 2023-2025 WMP) at 43-45 and 102.

[133] Final Decision on PG&E's 2023-2025 WMP at 102.

[134] Final Decision on PG&E's 2023-2025 WMP at 102.

[135] PG&E's response to data request CalAdvocates-PGE-2025WMP-08, question 1 lists experts in PG&E's Electric Distribution Engineering, EPSS, Remote Grid, Electric Distribution Reliability and REFCL teams engaged with PG&E's Grid Design team to assess effectiveness.

[136] Per Table ACI-PG&E-23-05-3 in PG&E's 2025 WMP at 55, PG&E estimates that undergrounding primary conductor is 97.7 percent effective, and undergrounding all conductor is 99.2 percent effective.

[137] "PG&E states that it showed effectiveness against ignition rate to be closer to 95 or 96 percent based on CPUC reportable ignitions. PG&E states that it used the higher estimate of 99 percent, because it notes that the 95 or 96 percent estimate does not account for wildfire frequency or consequence, emphasizing that none of the underground ignitions led to a fire greater than 10 acres. This approach, however, fails to account for the fact that much of the underground ignitions that have occurred have been in urban areas." Energy Safety, Final Decision on PG&E's 2023-2025 WMP at 44.

[138] "When evaluating recorded effectiveness, PG&E is seeing results closer to 69 percent to 72 percent in fault reductions for circuit segments that have 80 percent or greater covered conductor coverage." Energy

SCE's widespread deployment of covered conductor also support a higher estimate of effectiveness.[139] Notably, both of PG&E's deviations from empirical data allow PG&E to skew results in favor of undergrounding – PG&E's preferred mitigation measure.

Second, PG&E is inconsistent about the appropriate geographical scale of various mitigation measures. Among seven alternatives to undergrounding,[140] REFCL was the only mitigation assessed at a different scale than the other mitigations. PG&E estimates that REFCL can be applied at only 133 substations out of a total of 435 that serve the HFTD.[141] However it appears that "line removal and remote grid" was assessed as a system wide mitigation, which is certainly not a realistic assumption. PG&E has performed a very small amount of line removal to date and it is likely to be suitable in far fewer locations than REFCL.[142]

Third, PG&E provides incompatible estimates for mitigation sets. The estimated effectiveness of REFCL (assessed in combination with covered conductor, EPSS, and downed conductor detection) is more than 13 percent *lower* than the estimated effectiveness of a similar system *without* REFCL.[143]

Fourth, PG&E does not identify realistic mitigation sets. Only one analyzed mitigation set includes Public Safety Power Shutoffs (PSPS).[144] However, in the real world, PSPS would

Safety, Final Decision on PG&E's 2023-2025 WMP at 44.

[139] *See, e.g.*, Direct Testimony of the Mussey Grade Road Alliance Southern California Edison Company 2025 General Rate Case, May 12, 2023, Application A.23-05-010 at 67-69. This testimony estimates covered conductor effectiveness to range from 75 to 85 percent.

[140] See Table ACI-PG&E-23-05-3 in PG&E's 2025 WMP Update at 55. This table includes ten mitigations, of which two are undergrounding and one is "baseline" (0 percent effective), leaving seven viable alternatives to undergrounding.

[141] PG&E's response to data request CalAdvocates-PGE-2025WMP-07, question 2.

[142] Line removal with remote grid involves physically removing long distribution feeders and serving pockets of isolated customers via a standalone power system. Discussed in Section 8.1.2.7.1 in PG&E's 2023-2025 WMP R5 at 448. Per PG&E's response to CalAdvocates-PGE-2025WMP-07, question 6, REFCL could be applied at 133 substations that collectively serve 13,000 miles. It is unreasonable to expect that line removal with remote grid could be applied to even a substantial fraction of that mileage.

[143] Per Table ACI-PG&E-23-05-3 in PG&E's 2025 WMP at 55, PG&E estimates that covered conductor with EPSS (alternate 4) is 78.2 percent effective, while REFCL with covered conductor, EPSS, and downed conductor detection (alternate 9) is only 65 percent effective. In response to data request CalAdvocates-PGE-2025WMP-07, question 2, PG&E stated that this difference is due to REFCL only being applicable to 133 substations, which had different outage characteristics. However, given that REFCL is potentially applicable to more than half of PG&E's HFTD miles (13,000 miles out of approximately 25,000), it is unclear why the outage characteristics would be different enough to result in a substantial *decrease* in effectiveness despite the addition of REFCL.

[144] See Table ACI-PG&E-23-05-3 in PG&E's 2025 WMP Update at 55. Alternative 8 consists of EPSS

exist as part of all mitigation sets (even if deployed rarely). Similarly, covered conductor is included as a solo mitigation without operational mitigations such as EPSS. In a real-world situation, covered conductor would always operate in tandem with EPSS, PSPS, and other operational mitigations in high fire-risk areas, at least for the foreseeable future.

Finally, PG&E's analysis remains incomplete. Remarking on PG&E's past evaluation of mitigation alternatives, Energy Safety noted that "PG&E has not demonstrated that [its mitigation] evaluation also accounts for ongoing efforts such as vegetation and asset management."[145] PG&E still has not done so in its 2025 WMP Update.[146]

2. PG&E has not provided location-specific undergrounding effectiveness estimates.

Energy Safety directed PG&E to estimate "location-specific undergrounding effectiveness compared to combinations of mitigations."[147] PG&E states that it is developing a Wildfire Benefit Cost Analysis (WBCA) tool that will "evaluate location-specific factors"[148] and "incorporate cost effectiveness components, reliability considerations, and location-specific mitigation effectiveness calculations."[149] However, in response to discovery, PG&E clarified that the WBCA will only evaluate effectiveness at the circuit-segment level.[150]

and PSPS on bare conductor.

[145] Energy Safety, Final Decision on PG&E's 2023-2025 WMP at 102.

[146] See Table ACI-PG&E-23-05-3 in PG&E's 2025 WMP Update at 55. This table includes "baseline" at 0 percent effectiveness, and bare conductor with EPSS and PSPS, but does not include any analysis of the effects of ongoing vegetation and asset management to the baseline.

[147] Final Decision on PG&E's 2023-2025 WMP at 102.

[148] "When selecting the mitigation to implement, PG&E will use the WBCA output and then evaluate location-specific factors (e.g., tree fall-in risk, ingress and egress issues, reliability impacts) and risk sub-drivers (e.g., vegetation, animals, vehicles, etc.) along the target circuit segment." PG&E's 2025 WMP Update at 57.

[149] PG&E's 2025 WMP Update at 51.

[150] "Outputs from the Wildfire Distribution Risk Model (WDRM) are aggregated to the circuit segment level as the best model view for system hardening work. While individual pixel level data is available, the circuit segment view has less noise than the pixel level output. As such, the mean probability of ignition for each sub-driver, as output from WDRM, is assumed to be uniform across an entire circuit segment. Accordingly, the risks from individual sub-driver 'outage combinations' are assumed to be uniform across that circuit segment as well." PG&E's response to data request CalAdvocates-PGE-2025WMP-08, question 3.

PG&E's risk model calculates probabilities of ignition due to various ignition drivers, such as vegetation contact, asset failure, animal contact, and more.[151] By assigning an aggregate mean risk to the whole circuit segment, PG&E assumes that the probability of ignition for each sub-driver is *uniform* along the entire circuit segment.[152] Circuit segments are miles long and may traverse distinct areas with differ terrain, vegetation, and risk levels. An aggregate mean risk can mask a location of much higher ignition risk within a long circuit segment. In more general terms, the longer the circuit segment, the greater the chance of overlooking a distinct part of the segment with heightened ignition risk.

Circuit segments can vary greatly in length, and are typically much longer than individual system hardening projects. As discussed in Section IV.A.1 of these comments, the riskiest 8,000 miles in PG&E's territory represent approximately 50 percent of the total wildfire risk (according to WDRM v4). These 8,000 miles consist of 744 circuit segments with a median length of 7 miles and a maximum length of 74 miles.[153] In contrast, the 654 projects in PG&E's 2023-2026 system hardening workplan that include undergrounding have a median length of only 1.8 miles and a maximum length of 12.6 miles.[154]

Overall, the scale of PG&E's undergrounding effectiveness estimates is coarser than the scale of PG&E's undergrounding projects. PG&E estimates effectiveness for circuit segments, which are larger than the specific locations where PG&E performs undergrounding projects.

This disparity in lengths between circuit segments and actual undergrounding projects demonstrates the necessity of location-specific analyses, which PG&E has stated it *will not perform*.[155]

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[151] PG&E's response to data request CalAdvocates-PGE-2025WMP-05, question 1 lists 23 ignition drivers.

[152] PG&E's response to data request CalAdvocates-PGE-2025WMP-08, question 3.

[153] Analysis of PG&E's WDRM v4, provided in response to data request CalAdvocates-PGE-2025WMP-05, question 5.

[154] Analysis of PG&E's system hardening workplan, provided in response to data request CalAdvocates-PGE-2025WMP-03, question 8.

[155] "The WBCA will not adjust for outage combinations on a scale smaller than a circuit segment." PG&E's response to data request CalAdvocates-PGE-2025WMP-08, question 3.

3. PG&E has not justified its choice to underground at locations where analysis would recommend alternatives.

Also entirely absent from PG&E's 2025 WMP Update are the required justifications for undergrounding at locations where PG&E's own analysis recommends a different mitigation measure. As Cal Advocates demonstrated in 2023, PG&E's decision-making process for its current system hardening workplan used cost-benefit estimates that were skewed toward undergrounding.[156] Moreover, we showed that even where PG&E's decision tree determined that overhead hardening was the most appropriate option, PG&E still opted to underground.[157]

Energy Safety reasonably directed PG&E to justify choosing undergrounding where PG&E's analysis recommended a different mitigation.[158] In its 2025 WMP Update, PG&E fails to provide either a list of such projects or a justification for undergrounding against the recommendations of its own decision-making process.[159]

4. PG&E has not provided cost-effectiveness estimates for projects driven by reliability risk.

Energy Safety directed PG&E to identify "any projects driven by reliability risk as opposed to wildfire risk," which includes cost-effectiveness scores and an explanation as to why the project was prioritized for hardening.[160]

In response, PG&E listed 45 projects chosen primarily for reliability benefits.[161] PG&E states that these undergrounding projects were previously selected using WDRM v2 and v3, which did not incorporate cost-effectiveness for individual projects; thus, cost-effectiveness

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[156] *Public Advocates Office Opening Comments on Pacific Gas and Electric's 2023-2025 Wildfire Mitigation Plan Supplemental Response to Revision Notice*, October 13, 2023 at 6-10.

[157] *Public Advocates Office Opening Comments on Pacific Gas and Electric's 2023-2025 Wildfire Mitigation Plan Supplemental Response to Revision Notice*, October 13, 2023 at 6-10.

[158] Final Decision on PG&E's 2023-2025 WMP at 102.

[159] PG&E's 2025 WMP Update at 57 includes a brief, high-level discussion of how PG&E will select mitigations, but does not respond to Energy Safety's requirement that, "*For each location* where PG&E's analysis recommends a mitigation other than undergrounding, PG&E must provide justification for choosing undergrounding." Final Decision on PG&E's 2023-2025 WMP at 102 (emphasis added).

[160] Final Decision on PG&E's 2023-2025 WMP at 102.

[161] Table ACI-PG&E-23-05-4 in PG&E's 2025 WMP Update at 59-61.

estimates are not available.[162] In fact, all 45 projects were, in fact, selected by WDRM v2, which is up to four years out-of-date.[163]

Furthermore, as discussed in Section IV.A.2 of these comments, the fact that these projects were selected by an older version of the risk model does not exempt them from evaluating cost-effectiveness scores under its newest risk model. It is more important for PG&E to perform this analysis now to ensure that it does not impose undue costs on ratepayers without corresponding benefits. PG&E could perform an analysis of these projects with its current risk model.

5. PG&E has not estimated the cumulative risk exposure of its mitigation initiative portfolio, taking into account the time value of risk.

Energy Safety directed PG&E to "estimate … the cumulative risk exposure of its mitigation initiative portfolio, taking into account the time value of risk as part of mitigation comparisons."[164]

In response, PG&E provides a simplistic and potentially misleading chart. PG&E's graphic shows the cumulative risk reduction for a given length of undergrounding, compared to hardening the same miles with covered conductor over a 53-year span.[165] The chart accounts for neither operational mitigations[166] nor the differences in implementation between undergrounding and covered conductor. This latter point is crucial, given that PG&E can install 3 to 4 miles of covered conductor for each mile of underground cable (which only removes 0.8 miles of

[162] PG&E's 2025 WMP Update at 57.

[163] Per Table PG&E-B.1.1-2 in PG&E's 2025 WMP Update at 8, WDRM v2 includes vegetation data through 2018, conductor asset data through 2020, and is trained on ignition events from 2015-2019.

[164] Energy Safety, Final Decision on PG&E's 2023-2025 WMP at 102.

[165] Figure ACI-PG&E 23-05-1 in PG&E's 2025 WMP Update at 57.

[166] The chart assumes a maximum risk reduction of approximately 69 percent for undergrounding and 48 percent for covered conductor. However, per Table ACI-PG&E-23-05-3 in PG&E's 2025 WMP Update at 55, covered conductor with operational mitigations is approximately 80 percent as effective as undergrounding (78.2% vs 97.7%). As a result, the chart should show a maximum risk reduction of 80% x 69% = 55% for covered conductor.

overhead conductor)[167] and at three times the speed.[168] In short, undergrounding poses greater financial and opportunity costs of installation, repair, and replacement, and it takes longer. PG&E constrains its comparison by equivalent *mileage*. However, a more appropriate comparison of equivalent *cost* would show that covered conductor can achieve far more (and more quickly realized) systemic risk reduction.[169]

Furthermore, Energy Safety did not ask for a comparison of cumulative risk *reduction* between mitigation initiatives, but for cumulative risk *exposure*. PG&E's analysis correctly shows that, over the first decade of system hardening, covered conductor will remove substantially more wildfire risk than undergrounding.[170]

A more accurate analysis (which should compare deployments at equivalent cost) would show that covered conductor mitigates more risk in both the near and long term.[171] The exigent demands of wildfire mitigation – the time value of risk – should compel PG&E to consider covered conductor more seriously. Covered conductor can provide maximum risk reduction at reasonable cost to ratepayers in a speedy fashion.

6. Energy Safety should require PG&E to revise and resubmit its WMP to fully comply with ACI PG&E-23-05.

PG&E has failed to comply with Energy Safety's requirements in its decision on PG&E's 2023-2025 WMP. Given PG&E's inadequate response to the requirements of ACI PG&E-23-05, Energy Safety should issue a revision notice and direct PG&E to revise and resubmit its 2025 WMP Update.

In its revised WMP, PG&E should fully comply with all required actions listed in ACI PG&E-23-05. This should involve the following at a minimum:

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[167] As discussed in Section IV.A.1 of these comments, undergrounding costs approximately $2.95 million per mile and covered conductor costs approximately $0.86 million per mile. Since a single undergrounding mile only removes, on average, 0.8 miles of overhead line, the equivalent cost per mile of overhead line removed is $3.7 million per mile, or 4.3 times the cost of a single mile of covered conductor.

[168] "Overhead hardening can be completed at a rate of approximately three times that of undergrounding." PG&E's 2025 WMP Update at 56.

[169] See analysis in Section IV.A.1 of these comments.

[170] Figure ACI-PG&E 23-05-1 in PG&E's 2025 WMP Update at 57.

[171] See analysis in Section IV.A.1 of these comments.

- PG&E should complete its comparative analysis of alternative mitigations and mitigation combinations using observed, in-field effectiveness data.
- PG&E should elaborate on its REFCL analysis.
- PG&E should remove PSPS from its analysis of mitigation sets (unlike other mitigations considered, PSPS is specific to moments in time rather than locations).
- PG&E should provide location-specific undergrounding effectiveness estimates, compared to other mitigations for its undergrounding projects, using its most mature risk model (WDRM v4).
- PG&E should provide cost-effectiveness estimates for the 45 projects driven by reliability risk, using its most mature risk model (WDRM v4).
- PG&E should provide a more comprehensive comparative analysis of its mitigation alternatives (both single mitigations and mitigation sets), by incorporating cumulative risk exposure.

If PG&E cannot complete these actions by the end of 2024, PG&E's revised WMP should include a description of PG&E's progress on each of the above items and an expected timeline for completion. Finally, Energy Safety should identify the specific result (i.e., rejection, further revision required, or other consequence) if PG&E's revised WMP fails to comply with ACI PG&E-23-05.

B. PG&E did not comply with ACI PG&E-23-12.

ACI PG&E-23-12 addressed PG&E's backlog of overdue and unresolved asset work orders. ACI PG&E-23-12 required PG&E to adjust its 2025 tag closure target for 2025 to 79,200 tags. Energy Safety stated that if PG&E exceeds its target in 2024, it may reduce its target for 2025 by an equal amount.[172] In other words, ACI PG&E-23-12 required PG&E to fix and close a minimum of 125,200 tags between 2024 and 2025.[173]

PG&E's 2025 WMP Update fails to comply. PG&E proposes to reduce its 2025 target by over 15,000 tags, while holding the 2024 target constant.[174] The overall effect is to reduce the combined 2024-2025 target to 109,747 tags, which is less than what ACI PG&E-23-12 requires. PG&E seeks to rationalize this reduction on the grounds that it exceeded its work order backlog

[172] Final Decision on PG&E's 2023-2025 WMP at 106-107.

[173] Final Decision on PG&E's 2023-2025 WMP at 106-107. PG&E must address 46,000 tags in 2024 and 79,200 tags in 2025, but may adjust its 2025 target downward if it exceeds its 2024 target.

[174] PG&E's 2025 WMP Update at 83.

remediation target by 15,453 tags in 2023.[175] However, this fact is irrelevant to the requirements that Energy Safety established.[176]

Table 4 below illustrates PG&E's targets for resolving maintenance tags for 2023 through 2025.

Table 4
PG&E's maintenance tag backlog targets[177]

	2023 target (actual)	2024 target	2025 target	2024-2025 combined target
Requirements of ACI PG&E-23-12	29,000	46,000	79,200	125,200
PG&E's 2025 WMP Update	29,000 (44,453)	46,000	63,747	**109,747**

Table 4 shows the requirements of ACI PG&E-23-12 and PG&E's current proposed targets for resolving maintenance tags. PG&E's proposal would reach the 2023-2025 WMP's overall, three-year target (resolving 154,200 tags in 2023-2025). However, PG&E plans to dial back its effort in 2025.

PG&E states that it "should not be penalized for resolving these backlog tags earlier than anticipated."[178] It is important to keep in mind that PG&E's backlog has resulted from its repeated failure to comply with General Order 95.[179] It would not be a penalty to require PG&E to conform to Energy Safety's direction and close 125,200 overdue tags in 2024 and 2025.

PG&E's 2025 WMP Update does not comply with Energy Safety's direct requirements. Changes to PG&E's tag priority classifications and inspection checklist were not reported in its

[175] PG&E's 2025 WMP Update at 83. PG&E uses the 2023 excess to reduce its 2025 target by a matching amount, from the required 79,200 tags to 63,747 tags.

[176] PG&E proposes to hold the *2023-2025* target constant at 154,200 tags, despite Energy Safety's clear and specific direction to hold the 2024-2025 target constant at 125,200.

[177] Source data from Table ACI-PG&E-23-12-1 in PG&E's 2025 WMP Update at 84.

[178] PG&E's 2025 WMP Update at 83.

[179] See discussion in *Comments of the Public Advocates Office on the 2023 to 2025 Wildfire Mitigation Plans of the Large Investor-Owned Utilities*, May 26, 2023 at 31-33.

2025 WMP Update and may result in an appearance of improvement to the backlog.[180] PG&E's non-compliance thus raises concerns.

VIII. CONCLUSION

Cal Advocates respectfully requests that Energy Safety adopt the recommendations discussed herein.

Respectfully submitted,

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[180] Discussed in Section VI.B of these comments.