Safety Policy Division Evaluation Report on PG&E 2024 RAMP Application (A.)24-05-008

November 8, 2024

California Public Utilities Commission

Contents

Executive Summary

Background

The Safety Policy Division (SPD) of the California Public Utilities Commission (Commission) is responsible for evaluating Pacific Gas and Electric Company's (PG&E) 2024 Risk Assessment and Mitigation Phase (RAMP) Application (A.)24-05-008 filed with the Commission. The PG&E 2024 RAMP contains PG&E's detailed assessment of its top safety risks and risk mitigation programs and projects, and the associated expenditures PG&E proposes to address these risks for the upcoming 2027 to 2030 General Rate Case period (Test Year 2027 GRC). This report details the results of SPD's evaluation of the PG&E 2024 RAMP.

This is the first RAMP application filed by any of the four largest energy utilities, including PG&E, applying a new cost-benefit approach to assess risk mitigation proposals. This new cost-benefit approach was adopted in Phase 2 Decision (D.)22-12-027 of the Risk-Based Decision-Making Framework (RDF) rulemaking proceeding, R.20-07-012. The RDF adopted in this Phase 2 decision governs the risk evaluation framework applicable to this RAMP proceeding. The Phase 2 RDF supersedes the S-MAP Settlement Agreement, which governed PG&E's 2020 RAMP. Central to the Phase 2 RDF is monetizing the Safety and Reliability attributes of risk, enabling a cost-benefit ratio to be calculated for each risk mitigation program or project.

Documents Reviewed by SPD

The PG&E 2024 RAMP Application consists of the application document and associated workpapers. The included workpapers are electronic files in Excel spreadsheets and PDF documents obtained from PG&E's web portal for the 2024 RAMP proceeding.

In addition to the above documents, SPD issued 23 data requests to PG&E. PG&E provided written responses to these data requests. Finally, SPD also reviewed and considered informal comments filed by numerous parties in early October.

Evaluation Scope and Methodology

The Scoping Memo prescribed the scope of issues for this RAMP proceeding and formed the basis of SPD's evaluation. Additionally, SPD's evaluation relied on the governing Risk-Based Decision-Making Framework (RDF) document applicable to this RAMP, contained in D.22-12-027 and the decision's Appendix A.

SPD used a standard template prepared by SPD to evaluate each of the 12 risk chapters contained in the PG&E 2024 RAMP. Using this approach, SPD evaluated each risk chapter on the following categories:

Risk Description
Risk Bow Tie
Risk Exposure
Risk Tranches
Risk Drivers and Frequencies
Cross-Cutting Factors
Consequences
Climate Adaptation Vulnerability Assessment
Controls and Mitigations
Alternatives Analysis
CBR Calculations

SPD did not verify the reasonableness of PG&E's cost projections as this was beyond the scope of this evaluation. To the extent uncertainties and potential errors may be found in PG&E's mitigation cost estimates, those uncertainties and potential errors would carry through to the cost-benefit ratio calculations, leading to potential errors in the mitigation decisions. Therefore, the cost estimates should be substantiated in the TY 2027 GRC.

General Conclusion

In general, the PG&E 2024 RAMP complies with the requirements of the Phase 2 RDF. No areas of deficiency are severe enough to warrant SPD's recommendation that the Commission reject this RAMP application.

However, SPD noted numerous less significant deficiencies and areas of concern in each risk chapter. SPD pointed out these deficiencies and areas of concern and made recommendations to PG&E for improvement. SPD recommends that that PG&E correct these deficiencies before filing its Test Year 2027 GRC.

Global Observations

1. **Effects of Monetizing Safety and Reliability Attributes** – PG&E's monetization of the Safety and Reliability attributes results in placing less emphasis on safety and more emphasis on reliability, especially electric reliability:

Table 1: Non-Risk-Adjusted Attribute Unit-Value Ratios 2024 vs. 2020 RAMPS

Attribute	Unit	2020 RAMP Implied Unit Value[10]	2024 RAMP Selected Unit Value	2024/2020 Ratio
Safety	$/fatality	$100 million	$15.2 million	15.2%
Electric Reliability	$/CMI	$1.00	$3.17	317%
Gas Reliability	$/customer affected	$1,333	$1,570	118%
Financial	$	$1	$1	100%

Two derivative effects flow from this recalculation of the Safety attribute:

- In terms of risk ranking, risk events with significant potential property damage impacts (which would be captured by the Financial attribute) and significant reliability impacts would have higher relative risk rankings than in the 2020 RAMP. Likewise, risk events in which safety impacts dominate would generally rank lower in this RAMP than in 2020.
- For the same risk event, mitigations that are relatively more effective at lessening the severity of electric service disruptions (as opposed to having more safety reduction impact) would be more highly favored (i.e., would have a relatively higher CBR) in the 2024 RAMP than they would have been in the 2020 RAMP.

2. **Electric Reliability Cost** – PG&E calculated the electric reliability value of $3.17 based on a territory-wide average assuming equal distribution of residential, commercial, and industrial customers in all areas. However, SPD finds that this method overestimates the value of reliability in rural areas, comprising the bulk of PG&E's high fire threat district (HFTD) areas, where few commercial or industrial customers are located. This high reliability value then inflates the apparent benefit of wildfire mitigation proposals in these areas. SPD recommends that PG&E use a disaggregated approach to estimate reliability values.

3. **Risk-Averse Risk Scaling Function** – PG&E constructed a new risk-averse risk scaling function based on risk premium ratios calculated from insurance products or catastrophe bonds it purchases to transfer risks associated with low-frequency, high-consequence events to reinsurers and the capital market. SPD evaluated this approach and concluded that it is valid.

Though SPD found PG&E's methodology to derive risk-averse risk-scaling factors was justified, it would also make sense for PG&E to present parallel RAMP analyses based on a risk-neutral, completely linear risk-scaling function. This would allow the Commission, Commission staff, and other GRC stakeholders to gain insight into what effects the risk-averse scaling function used in this RAMP had on the risk evaluation, risk mitigation decisions, and expenditure levels. SPD recommends that PG&E submit a parallel set of risk analyses in the 2027 GRC filing using a risk-neutral scaling function. At a minimum, the parallel analyses should contain risk scores and cost-benefit ratios of the proposed and alternative mitigations (including mitigations classified as controls) using this risk-neutral scaling function.

4. **No identification of Compliance Requirements** – PG&E frequently did not identify mitigations (or controls) that are needed to comply with regulatory requirements or adequately cite or explain those requirements.

5. **Continued Funding of Controls with Low CBR** – There is an apparent presumption by PG&E throughout this RAMP that mitigation programs approved in prior GRCs are given an almost automatic green light for continued approval and funding in the TY 2027 GRC. Unless PG&E identifies these controls as compliance requirements, PG&E should treat each such controls as a newly proposed mitigation requiring adequate justification for its continued funding in the TY 2027 GRC since all non-compliance-related controls and newly proposed mitigations are in competition with one another for funding from the same limited pool of ratepayer funds.

6. **Alternatives are often Unrealistic Alternatives** – The Alternative mitigations are often not realistic alternatives to the proposed mitigation plan. The primary proposed plan is often the pre-ordained mitigation plan, with the alternatives having unacceptably low cost-benefit ratios to be realistic alternatives to the proposed plan. Within each risk chapter, little uniformity was found regarding whether the Alternatives are alternatives to a mitigation or the entire proposed plan.

<u>Observations on Individual Risk Chapters</u>

Findings of deficiencies and areas of concern for each risk chapter and recommendations for improvement are found at the end of each risk chapter.

Background and Introduction

In accordance with the revised Rate Case Plan schedule adopted in Decision (D.)20-01-002,[1] Pacific Gas and Electric Company (PG&E) filed its 2024 Risk Assessment and Mitigation Phase (RAMP) application (A.)24-05-008 on May 15, 2024. This 2024 RAMP application, covering expenditure years 2027 to 2030, was filed in advance of PG&E's Test Year 2027 General Rate Case (GRC) application.

According to the Rate Case Plan in D.20-01-002 and as directed by the Scoping Ruling in A.24-05-008, the Safety Policy Division (SPD) was tasked to evaluate PG&E's 2024 RAMP application. This report summarizes the evaluation results.

In D.22-12-027 in Phase 2 of the Risk-Based Decision-Making Framework (RDF) rulemaking proceeding, R.20-07-013, the California Public Utilities Commission (Commission) adopted a cost-benefit framework[2] that the four largest jurisdictional energy utilities must follow to evaluate RAMP risk mitigation options and justify the proposed risk mitigations in their RAMP and GRC applications. Central to this new cost-benefit approach in D.22-12-027 is expressing in dollar values all the components in the risk value function, which was previously represented by a Multi-Attribute Value Function (MAVF) under the Settlement Agreement framework adopted in D.18-12-014 of the Safety Model Assessment Phase (S-MAP) consolidated proceeding (A.15-05-002 et al). The monetization of the safety and reliability terms in the utility's risk function enables the calculation of an actual cost-benefit ratio in which both the numerator (representing the net present monetized value of risk reduction benefits) and the denominator (representing the net present value of the associated risk mitigation program/project costs) are expressed in the same dollar units for each of the mitigation programs and projects to be evaluated. The resulting approach using cost-benefit ratios permits a more logically sound (i.e., "apples-to-apples") comparison of mitigation options than the now-superseded risk-spend efficiency approach used in previous RAMP applications.

PG&E's 2024 RAMP is the first RAMP application from the four largest energy utilities in which the new cost-benefit framework[3] adopted in D.22-12-027 applies.

[1] Revised Rate Case Plan Decision, D.20-01-002, Appendix B.

[2] The cost-benefit framework is detailed in Appendix A of D.22-12-027

[3] *Id.*

Explanation of Terms

This section clarifies the definitions of several terms that are used throughout this report.

RAMP Report – The individual chapters and appendices of the PG&E 2024 RAMP application are collectively referred to as the "RAMP Report." Supporting workpapers, including various electronic files such as spreadsheets, are also collectively part of the RAMP Report.

2024 RAMP—Utilities refer to RAMP applications by the calendar year in which the application is filed. The PG&E 2024 RAMP has a 2027 Test Year and covers expenditures from 2027 to 2030.

TY 2027 GRC – The Commission and the utilities refer to General Rate Case (GRC) applications by the test year (TY) on which the general rate case estimates and calculations were based. PG&E refers to the upcoming GRC application that will be filed in the calendar year 2027 as the "TY 2027 GRC."

Cost-Benefit Ratio (CBR) – As used throughout the PG&E 2024 RAMP Report and this SPD evaluation report, the cost-benefit ratio is defined as the ratio of the dollar value of Mitigation Benefit (in the numerator) divided by the Mitigation cost estimate (in the denominator). This definition is consistent with the adopted definition in the governing framework for this RAMP contained in Appendix A of D.22-12-027. The alternative term **Benefit/Cost Ratio** may occasionally be used in this report to refer to this definition of CBR.

Additional terms are defined in the governing Risk-Based Decision-Making Framework document contained in Appendix A of D.22-12-027.

Scope and Methodology of Evaluation

The Scoping Memo in the PG&E 2024 RAMP proceeding enumerates the following questions for consideration in the evaluation of PG&E's RAMP Report:

The issues to be determined or otherwise considered are:

1. Whether PG&E's RAMP filing is complete and in compliance with RAMP related and governing decisions, including Decision (D.) 14-12-025, D.18-12-014 (the S-MAP settlement decision), D.21-11-009, and D.22-12-027 (Risk OIR Phase II Decision);
2. Whether PG&E adequately demonstrates how it uses its RAMP model and risk analysis in selection and implementation of specific mitigation projects and programs;
3. Whether gaps exist in the RAMP Report in identifying enterprise-level risks and considering mitigation options, including but not limited to:
    a. Whether PG&E has adequately modeled the risks and mitigations for Public Safety Power Shutoffs (PSPS) and Enhanced Powerline Safety Settings (EPSS);
    b. Whether PG&E adequately demonstrates how it accounts for lifecycle costs and benefits when assessing risk mitigation programs and projects, including depreciation costs and negative net salvage costs;
    c. Whether PG&E has reasonably implemented the Cost Benefit Approach directed by D.22-12-027;
    d. Whether PG&E demonstrated the reasonableness of its Risk Scaling Function;
    e. Whether PG&E has complied with the RAMP graphical progress reporting requirements of D.22-10-002;
    f. Whether PG&E has adequately assessed operational performance in its quantitative risk analysis;
    g. Whether PG&E has proposed reasonable alternative mitigations;
    h. Whether wildfire mitigation risk reduction effectiveness values, reliability improvement, and costs are adequately reflected and reasonable;
    i. Whether PG&E has adequately explained its proposed mitigation plans; and
    j. Whether PG&E's risk-event tranches are appropriately granular;
4. Whether the utility's analysis is transparent and allows for independent validation of its results;
5. Whether RAMP feedback has been meaningfully evaluated and, when appropriate, incorporated into PG&E's GRC filing;

6. Whether PG&E has reasonably implemented the Environmental and Social Justice Pilot study and other related direction ordered in D.22-12-027; and
7. Whether the Application aligns with or impacts the achievement of any of the nine goals of the Commission's Environmental and Social Justice Action Plan.

Where SPD staff observed notable flaws in PG&E's RAMP Report, the evaluation explicitly identified the flaws and highlighted corresponding recommendations for improvement. Where SPD staff had no significant observations on a topic, the SPD report remains silent.

One aspect of the evaluation revolved around analyzing and verifying mitigation cost projections presented by PG&E used in the cost-benefit ratio calculations. The verification of mitigation cost estimates was beyond the scope of this evaluation. To the extent uncertainties and potential errors may be found in PG&E's mitigation cost estimates, those uncertainties and potential errors would carry through to the cost-benefit ratio calculations, leading to potential errors in the mitigation decisions. Therefore, the cost estimates should be substantiated in the TY 2027 GRC.

As was the practice in recent SPD RAMP evaluation efforts, SPD's evaluation of the PG&E 2024 RAMP used a uniform template to evaluate each RAMP risk chapter. This standardized template approach allowed for a more uniform evaluation, though some style variations exist as different SPD team members authored different chapters.

SPD staff reviewed each risk chapter in detail. The evaluations examined the soundness and adequacy of the overall risk assessment and analytical approach and whether the application complies with the governing Risk-Based Decision-Making Framework contained in Appendix A of D.22-12-027.

Similar to the practice in recent RAMPs, several intervenor parties submitted informal comments to SPD. These comments provided valuable input into SPD's evaluation process. Energy Producers and Users Coalition (EPUC) and Indicated Shippers, The Mussey Grade Road Alliance (MGRA), the Public Advocates Office (Cal Advocates), Small Business Utility Advocates (SBUA), and The Utility Reform Network (TURN) submitted informal comments to SPD on October 9, 2024. MGRA and Cal Advocates, re-submitted their informal comments with minor corrections, respectively, on October 11, 2024, and October 15, 2024. These informal comments are appended to the end of this report.

Key Differences between 2024 RAMP and 2020 RAMP

As a result of the RDF adopted in D.22-12-027, which superseded the S-MAP Settlement Agreement framework, several key differences between PG&E's 2020 RAMP and the 2024 RAMP were found:

1. The safety, reliability, and financial attributes in the risk calculation in the 2024 RAMP are expressed in dollar values.[4] In the 2020 RAMP, these three attribute values were expressed as a unitless percentage of each attribute's estimated maximum value.

As required by the RDF in the 2024 RAMP, monetizing the safety attribute requires using an explicit Value of Statistical Life (VSL) to convert the estimated fatalities and injuries into an equivalent safety value expressed in dollars. Likewise, the electric reliability attribute is converted into dollars using the Interruption Cost Estimator (ICE) calculator, published by the Lawrence Berkeley National Laboratory. The monetized value of gas reliability attribute is based on the implied gas reliability value using the Multi-Attribution Function from PG&E's 2020 RAMP.

2. Citing guidance from D.14-12-025 to account for the safety impact caused by reliability-induced issues, PG&E introduced a new sub-attribute under the Safety Attribute: (Reliability-induced) Indirect Safety.[5]

3. PG&E uses a California-adjusted VSL of $15.2 million to evaluate the safety attribute and indirect safety sub-attribute.[6] In the 2020 RAMP, PG&E's MAVF had an implied VSL of $100 million. As a result of using this explicit VSL of $15.2 million, and other changes mentioned in points 1 and 2 above, the relative importance of the safety attribute decreased significantly relative to the reliability and financial attributes. This resulted in a dramatic impact on the relative rankings of some RAMP risks between the 2020 RAMP and the 2024 RAMP, as shown in Figure 1 below.

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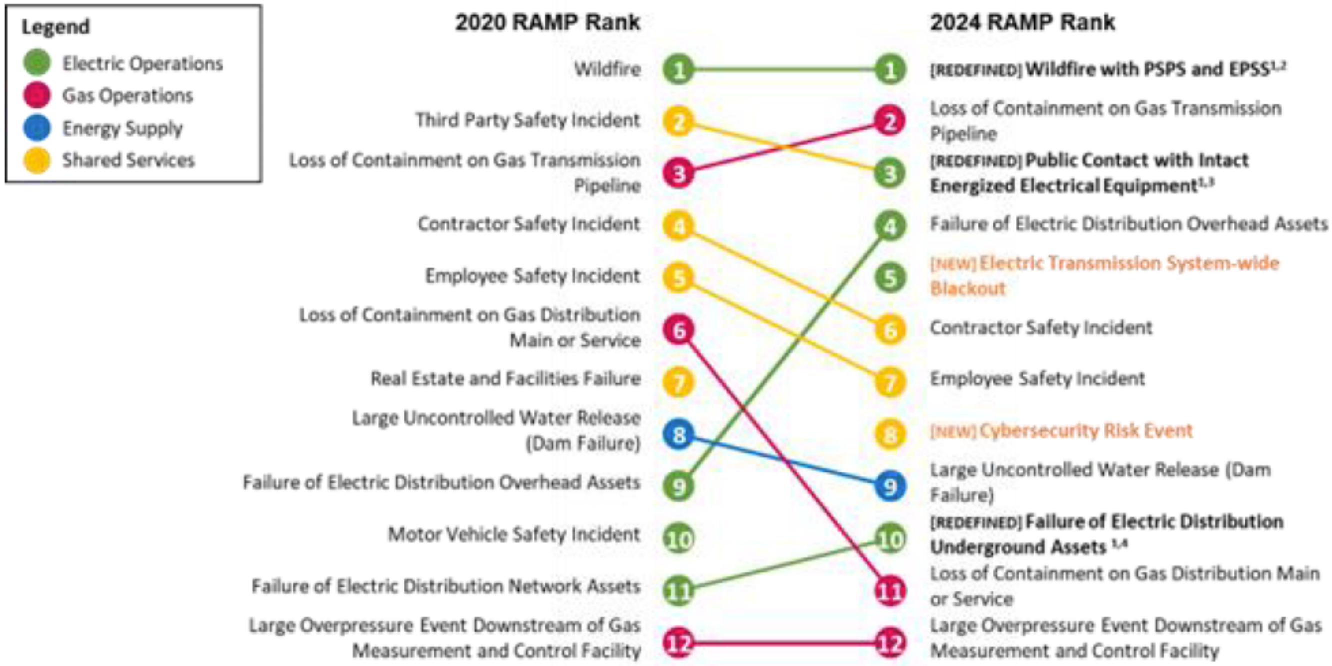
[4] Details of the monetization methodology are specified in Ordering Paragraph 2 of D.22-12-027.

[5] PG&E 2024 RAMP, PG&E-2, Page 2-7, Line 1.

[6] PG&E 2024 RAMP, PG&E-2, Page 2-11, Table 2-4, Line 6.



[1] *Risk event definitions/scope have changed since the 2020 RAMP.*
[2] *Wildfire risk score now also reflects consequences of Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS).*
[3] *For Public Contact, the scope was narrowed to focus on members of the public and third-party contractors experiencing serious injuries or fatalities resulting from interactions with intact energized electric facilities, not involving asset failure.*
[4] *Two risk models that were previously separate, Failure of Electric Distribution Network Assets and Failure of Electric Distribution Underground Assets, have been assembled into a single model.*

Figure 1: Safety Risk Rank Comparison Between 2020 and 2024 RAMP Filings[7]

4. In accordance with D.22-12-027, PG&E developed an Environmental and Social Justice (ESJ) Pilot Study Plan (PSP). The ESJ PSP was included in PG&E's 2024 RAMP application and evaluated by SPD as part of the RAMP evaluation.

5. In the PG&E 2024 RAMP, PG&E used a risk-averse scaling function explicitly based on the implied risk premiums of insurance products and catastrophe bonds PG&E purchased to cede risks to the insurance companies and the financial market. In the 2020 RAMP, PG&E specified a risk-averse scaling function without referencing any risk premiums implied by insurance products.

[7] PG&E 2024 RAMP, PG&E-1, Page 1-12, Figure 1-1.

6. When calculating cost-benefit ratios, the allocated costs of relevant foundational activities are combined with the cost of an enabled mitigation program to arrive at the total cost for each mitigation program. Foundational activities are initiatives that support or enable two or more mitigation programs but do not directly reduce the consequences or reduce the likelihood of safety risk events. This is a new requirement in the Phase 1 decision, D.21-11-009, of the RDF proceeding.[8] The impetus for this new requirement is to give a more realistic representation of the mitigation program costs.

7. In the 2020 RAMP, PG&E defined a serious injury as equivalent to 0.25 of a fatality. In the 2024 RAMP, PG&E used the Maximum Abbreviated Injury Scale (MAIS) based injury severity level adopted by the U.S. Department of Transportation (DOT) for the value of injury prevention.[9]

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[8] D.21-11-009, Ordering Paragraph 1..

[9] PG&E 2024 RAMP, PG&E-2, Page 2-7, Table 2-2.

PG&E's RAMP Risk Selection Process

The risk selection process used by PG&E to arrive at the 2024 RAMP risks is essentially identical to the process used in the 2020 RAMP. The primary difference is that the safety risk scores were converted into dollar values in the 2024 RAMP. Both RAMPs started with a list of enterprise-level risks from PG&E's Corporate Risk Register (CRR).

The RDF, Step 2A, Row 9 specifies the utilities' process for selecting RAMP risks. The process begins with the Enterprise Risk Register, identified by PG&E as its Corporate Risk Register (CRR). At the end of 2023, PG&E's CRR contained 32 event-based enterprise-level (or corporate-level) risk events. The PG&E RAMP Report does not describe how the 32 risk events were derived. Of these 32 enterprise-level risk events, 27 showed a non-zero safety risk score.

RDF, Row 9 specified taking the top 40% of CRR risks based on the non-zero safety-only monetized risk scores. However, Row 9 is silent about whether risk scaling adjustments should be applied to the monetized safety-only risk scores before sorting. PG&E chose to apply risk scaling adjustment to the safety-only monetized risk scores before ranking and taking the top 40 percent. SPD finds either approach acceptable.

In PG&E's CRR, the top 27 non-zero safety-only monetized enterprise-level risks equated to 11 RAMP risks. PG&E included an additional risk, the Failure of Electric Distribution Underground Assets risk event, ranked just below the top 40%, for a total of 12 top enterprise-level risks. These 12 enterprise-level risks comprised the RAMP risks included in the PG&E 2024 RAMP.

Global Observations

This section identifies the more notable overarching observations, concerns, or deficiencies affecting the PG&E 2024 RAMP.

1. **Effects of Monetizing Safety and Reliability Attributes** - The most significant difference between the 2024 RAMP and previous RAMPs is the monetization of the safety and reliability attributes of risk. As previously noted in the section comparing the 2020 and PG&E 2024 RAMPs, one significant effect of monetizing the Safety attribute was to effectively place less emphasis on the Safety attribute relative to the Reliability and Financial attributes. This occurred because the attribute weights and ranges PG&E selected in the 2020 RAMP implied a very high VSL of $100 million, whereas, in the 2024 RAMP, in compliance with the monetization requirement, PG&E explicitly selected a California-adjusted VSL of $15.2 million. The relative impacts of monetizing the attribute terms between the 2020 RAMP and the 2024 RAMP are summarized in Table 2 below.

Table 2: Non-Risk-Adjusted Attribute Unit-Value Ratios between 2024 and 2020 RAMPS

Attribute	Unit	2020 RAMP Implied Unit Value[10]	2024 RAMP Selected Unit Value	2024/2020 Ratio
Safety	$/fatality	$100 million	$15.2 million	15.2%
Electric Reliability	$/CMI	$1.00	$3.17	317%
Gas Reliability	$/customer affected	$1,333	$1,570	118%
Financial	$	$1	$1	100%

Two derivative effects flow from this recalculation of the Safety attribute:

- In terms of risk ranking, risk events with significant potential property damage impacts (which would be captured by the Financial attribute) and significant reliability impacts would have higher relative risk rankings than in the 2020 RAMP. Likewise, risk events in which safety impacts dominate would generally rank lower in this RAMP than in 2020.
- For the same risk event, mitigations that are relatively more effective at lessening the severity of electric service disruptions (as opposed to having more safety reduction impact) would be more highly favored (i.e., would have a relatively higher CBR) in the 2024 RAMP than they would have been in the 2020 RAMP.

[10] This formula calculates the implied dollar value of a unit of consequence attribute:

Implied dollar value per unit of attribute A = [(relative weight of attribute A)/(relative weight of financial attribute)] x [(maximum range of financial attribute)/(maximum range of attribute A)]

Therefore,

Implied VSL = [(Safety weight for fatalities/Financial weight)] x [(maximum range of Financial attribute/maximum range of Safety attribute in terms of fatalities)]

Implied $/CMI = [(Electric Reliability weight for CMI /Financial weight)] x [(maximum range of Financial attribute/maximum range of Electric Reliability attribute in terms of CMI)]

Implied $/gas customer affected = [(Gas Reliability weight for gas outage /Financial weight)] x [(maximum range of Financial attribute/maximum range of Gas Reliability attribute in terms of customers affected)]

The above two bullet points are observations of the derivative effects resulting from the RDF's monetization requirement. Identifying these effects would allow the Commission and other GRC stakeholders to make informed decisions.

2. **Risk-Averse Risk Scaling Function** - A notable feature of PG&E's 2024 RAMP is using a new risk-averse risk scaling function. Under this new approach, risks are divided into three tiers.

Retention-based tier - The first tier represents risk exposure related to high frequency/ low consequence risk events. In this tier, PG&E often assumes losses under a certain amount as a deductible in insurance contracts, with a scaling factor of 1 for losses in this region.

Insurance-based tier – This tier represents risk exposure due to lower probability/higher magnitude risk events. Since losses in this tier are transferred to insurance companies through insurance policies, PG&E uses a scaling multiplier of 2 based on the risk premium multipliers of insurance products purchased to protect against exposure to losses in this tier.

Catastrophic tier – This tier represents exposure to risk events and losses of catastrophic magnitude. PG&E transfers risks in the catastrophic tier to capital markets and reinsurers via catastrophe (CAT) bonds and other products. PG&E selected a risk scaling factor of 7.5 for losses in this tier based on the risk premium multiplier of CAT bonds purchased to protect against these losses.

SPD reviewed the information PG&E presented and concluded PG&E's methodology to base risk scaling factors on the risk premium multipliers of insurance products and CAT bonds of the types that PG&E purchases to cede risk exposures to be sound and acceptable. Since risk exposures in the Insurance-based tier and the Catastrophic tier are ceded to either the insurance companies or the capital markets via insurance products or CAT bonds, the risk attitude factors embedded in the risk premium multipliers of those products are a valid representation of the risk-averse behavior applicable to this RAMP. The risk attitude of PG&E ratepayers, PG&E, and the insurance market and capital market converge on the risk exposure in these two upper tiers. The reason is the risk exposure in these two tiers has been transferred to the insurance and capital markets by the insurance products and CAT bonds. The only risk exposure facing ratepayers for losses in these upper-risk tiers are the premiums for which ratepayers are liable on the insurance products and CAT bonds that PG&E will purchase on the ratepayers' behalf to cede the risk exposure to the insurance companies and the capital market.

Though SPD found PG&E's methodology to derive risk-averse risk-scaling factors was justified, it would also make sense for PG&E to present parallel RAMP analyses based on a risk-neutral, completely linear risk-scaling function. This would allow the Commission, Commission staff, and other GRC stakeholders to gain insight into what effects the risk-averse scaling function used in this RAMP had on the risk evaluation, risk mitigation decisions, and expenditure levels. SPD recommends that PG&E submit a parallel set of risk analyses in its 2027 GRC filing using a risk-neutral scaling function. At a minimum, the parallel analyses should contain risk scores and cost-benefit ratios of the proposed and alternative mitigations (including mitigations classified as controls) using this risk-neutral scaling function.

3. **No identification of Compliance Requirements** - Throughout this RAMP, PG&E did not, as a general practice, identify mitigation programs (including those classified as controls) needed to comply with regulatory requirements. Often, these programs have very low cost-benefit ratios. SPD recommends that for the 2027 GRC and future RAMP applications PG&E should identify which mitigations and controls are needed to comply with regulatory requirements. PG&E should also identify the relevant regulatory requirement for each such mitigation and control. This information would allow for the assessment of the low cost-benefit ratios for these regulatorily required mitigations and controls in the proper context.

4. **Continued Funding of Controls with Low CBR** - There is an apparent presumption by PG&E throughout this RAMP that mitigation programs approved in prior GRCs (and are now classified as controls) are given an almost automatic green light for continued approval and funding in the TY 2027 GRC. This presumption is particularly jarring for controls with a very low cost-benefit ratio. Unless PG&E properly identifies these controls as compliance requirements, PG&E should treat each such control as a newly proposed mitigation requiring adequate justification for its continued funding in the TY 2027 GRC period, since all non-compliance-related controls and newly proposed mitigations are in competition with one another for funding from the same limited pool of ratepayer funds.

5. **Alternatives are often Unrealistic Alternatives** - The Alternative mitigations are often not realistic alternatives to the proposed mitigation plan. The primary proposed plan is often the pre-ordained mitigation plan, with the alternatives having unacceptably low cost-benefit ratios to be realistic alternatives to the proposed plan. Within each risk chapter, little uniformity was found regarding whether the Alternatives are alternatives to a mitigation or the entire proposed plan.

6. **Electric Reliability Cost** – SPD's concerns with PG&E's method to estimate the dollar value of reliability is discussed in detail in the next section.

Electric Reliability Cost

Following the requirement of Ordering Paragraph 2 in D.22-12-027, PG&E utilized the Interruption Cost Estimate (ICE) calculator[11] developed by Lawerence Berkeley National Laboratory (LBNL) to estimate the monetized value of the electric reliability attribute.

To make the calculator's results more relevant to PG&E's RAMP filing, PG&E elected to adjust some of the default California data inputs within the ICE calculator with PG&E-specific data. This includes updating the number of customers in each customer class and annual average usage for each customer class, the percentage of manufacturing customers within the two Commercial and Industrial classes, reliability inputs and outage distributions by time of day and season. The details of these updates can be found in Table 2-6 of the RAMP filing.[12] The natural units of electric reliability are measured by PG&E in customer minutes interrupted (CMI). PG&E calculated the final result of the ICE calculator as $3.17/CMI.

Observations:

PG&E elected to use a single, system-wide average value for reliability. The problem with a system-wide average is that it incorporates the high costs of an outage to Commercial and Industrial customers despite large parts of PG&E's territory having few, if any, such customers. Rural parts of California where certain risks are more likely to occur, such as wildfire, have few Commercial and Industrial customers.

This observation was confirmed by MGRA, who demonstrated that in the HFTD areas, 30 percent of customers live on circuit segments without Commercial and Industrial businesses. The average monetized value of electric reliability on these circuit segments would only be $0.68/CMI.[13] Disaggregating customer data into smaller spatial segments allows the ICE calculator to provide a more accurate valuation of electric reliability. As SPD pointed out the ICE calculator can be used to estimate the monetized value of electric reliability at a very granular level.[14]

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[11] https://icecalculator.com/home

[12] For additional details, the data request SPD-PGE-2024RAMP-001 asked PG&E to provide a table explaining each change they made to the ICE calculator's default values along with explanations for why they made each change. The results of that data request can be found in the file Module_1-Changes_Estimate_Interruption_Cost_v2.0_PGE.xlsx that was submitted along with the narrative response to the data request.

[13] Mussey Grade Road Alliance Informal Comments to the Safety Policy Division Regarding Pacific Gas and Electric Company's RAMP Filing (Revision 1), October 11, 2024, at 11.

[14] In one example from a study conducted by the Electric Power Board of Chattanooga highlighted on the ICE Calculator Website, the datasets of individual customer outages were connected with the ICE calculator. This allowed the accuracy of cost estimates of outages to be greatly improved in contrast with information summed or averaged across customers. For more information see: *ICE Calculator Case Study Overview: EPB Chattanooga Distribution Automation* https://eta-publications.lbl.gov/sites/default/files/nexant-ice-calculator-epb-dis-automation-dec-2015.pdf

After a series of data requests seeking reliability values based on HFTD geography, PG&E filed a supplemental response to SPD-PGE-2024RAMP-002 on June 11, 2024, which recorded the four new monetized values of electric reliability as such:

1. HFTD Tier 3-Extreme: $1.47/CMI
2. HFTD Tier 2-Elevated $2.05/CMI
3. Non-HFTD EPSS-capable $2.94/CMI
4. Non-HFTD Non-EPSS-capable $3.43/CMI

On July 8, 2024, and July 31, 2024, SPD received supplementary data request responses to SPD-PGE-2024RAMP-002 that included not only Wildfire with EPSS and PSPS risk results but also the results for Failure of Electric Distribution Overhead Assets and Failure of Electric Distribution Underground Assets. The total risk value for the overall Wildfire risk decreased by 21 percent from $7.66 billion to $6.03 billion. The results of the initial analysis are listed in Table 3 below.

Table 3: Updated risk values after applying the four monetized values of electric reliability[15]

Risk Event	Original Electric Reliability Consequence Value ($M)	Original Total Risk Value ($M)	% Change in Electric Reliability Consequence Value	Adjusted Electric Reliability Consequence Value ($M)	Adjusted Total Risk Value ($M)	% Change in Total Risk Value
Wildfire with PSPS and EPSS	5,466.24	7,666	-30%	3,828.17	6,027.66	-21.4%
Wildfire pre-PSPS/EPSS	1,041.13	19,633	-35%	677.24	19,269.26	-1.9%
Wildfire post-PSPS/EPSS	281.11	2,357	-16%	236.96	2,312.89	-1.9%
PSPS	3,552.58	3,655	-35%	2,325.28	2,427.41	-33.6%
EPSS	1,632.56	1,654	-22%	1,265.92	1,287.36	-22.2%
Failure of Electric Distribution Overhead Assets	3,174.63	3,354	-13%	2,761.75	2,940.63	-12.3%
Failure of Electric Distribution Underground Assets	685.55	728	1%	691.51	733.64	0.8%

This table demonstrates that for all but one risk event, disaggregating the calculation of electric reliability into four regions of PG&E's territory results in reductions in the electric reliability consequence value. The

[15] This table was generated by SPD Staff using the results found in the PG&E 2024RAMP Risk Values worksheet of RM-RMCBR-14 PG&E 2024 RAMP Risk Values_ICECalcAdj_by Customer.xlsx. This Excel file was submitted to SPD as part of RAMP-2024_DR_SPD_002-Q003 on July 31 2024. PG&E also provided the results of this data request using a linear risk scale in the Risk Values incl. Risk Neutral worksheet of the same Excel file.

increase in the electric reliability consequence value for the Failure of Electric Distribution Underground Assets risk event is due to the fact that this risk event is most likely to occur in the urban portions of PG&E's territory.[16] From SPD's perspective, the fact that there was a rise in the electric reliability consequence value in the Failure of Electric Distribution Underground Assets risk event demonstrates that disaggregation is a more accurate representation of risk that exists on PG&E's electrical grid.

Recommendations

SPD recommends that PG&E not use a territory wide average of the monetized value of electric reliability in its 2027 GRC. When preparing its 2027 GRC Application, SPD recommends that PG&E either use the disaggregated approach found in the SPD data requests or an equally logical approach to disaggregation that may be proposed by parties. For instance, in its Informal Comments TURN built upon SPD's data requests to calculate a more accurate disaggregated monetized value of electric reliability based on average SAIDI values from 2016-2022.

Rather than requiring PG&E to consider both the origin of the risk event and the spatial footprint of the outage as SPD did, TURN simplifies the analysis by recommending that PG&E use a weighted average of $1.83/CMI for calculating the monetized value of electric reliability across each of its risks.[17] Alternatively, MGRA's Informal Comments highlighted an approach for determining how different customer types are distributed across PG&E's HFRA circuit segments that resulted in a $2.13 CMI per customer. MGRA also noted that 30 percent of HFRA customers live on the 2,338 circuit segments without medium and large commercial or industrial businesses, but these customers are only responsible for 11 percent of CMI costs, reflecting an average per customer CMI of $0.68.[18]

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[16] For details see Tranche-Outcome_Analysis worksheet within RM-RMCBR-14 PG&E 2024 RAMP Risk Values_ICECalcAdj_by Customer.xlsx.

[17] For details see Informal Comments of The Utility Reform Network (TURN) on PG&E's RAMP Report, October 9 2024 at 2-5.

[18] Mussey Grade Road Alliance (MGRA) Informal Comments to the Safety Policy Division Regarding Pacific Gas and Electric Company's RAMP Filing (Revision 1), October 11 2024 at 10-11.

Safety Culture, Policy, and Compensation

Overview

PG&E submitted its 2024 RAMP Report in A.24-05-008. Exhibit PG&E-2, Chapter 5 of this RAMP Report describes PG&E's current processes and programs relating to safety culture, safety policies, and employee compensation relating to safety.

As described in the RAMP Report, PG&E has active, ongoing, and involved efforts underway to develop and increase awareness of its safety culture. PG&E organized these programs into five general areas: safety management systems, safety culture, leadership, governance, and employee/executive compensation related to safety. Before discussing these five program areas, below, we will discuss and recognize the Commission's current rulemaking proceeding addressing safety culture.

Rulemaking 21-10-001

In response to legislative directive (Senate Bill 901, Dodd, 2018), the Commission opened Order Instituting Rulemaking (R.) 21-10-001 to "Develop Safety Culture Assessments for Electric and Natural Gas Utilities." The purpose of this OIR is to develop a framework for each regulated investor-owned electric utility, natural gas utility, and gas storage operator, to develop and adopt a safety culture assessment framework, and to identify the structure, elements, and processes needed to establish and continuously improve their organization-wide safety culture.

This rulemaking is underway and involves many interconnected elements. PG&E is an active participating party in the proceeding, and SPD staff is also active in the proceeding in an advisory role to the Commission. In view of the open rulemaking proceeding, and the roles of PG&E and SPD, we will defer any specific observations or recommendations here. Instead, SPD describes each of the five program areas PG&E included in its RAMP Report.

PG&E Safety Culture Programs

1) Safety Management System

PG&E developed its "PG&E Safety Excellence Management System (PSEMS)" program as a systemic annual safety awareness and oversight approach. PSEMS manages processes, assets, and occupational health and safety to prevent injury and illness by controlling and governing assets and managing operating systems and processes. PSEMS includes improvement drivers in four areas: Asset Management, Occupational Health & Safety, Process Safety, and Organizational Culture & Safety Mindset.

2) Safety Culture

PG&E describes and defines its safety culture processes in two program areas: a "Safety Conscious Work Environment" that develops an ongoing management attitude to promote employee involvement and confidence in raising and resolving safety concerns; and, to create and embed "Traits of a Healthy Safety Culture." These traits include leadership, accountability, communication, shared values and beliefs, and continuous learning.

3) Leadership

PG&E's executive safety leadership includes the Chief Executive Officer (CEO), Chief Safety Officer (CSO), and five Regional Safety Directors. The CEO and CSO are responsible for the organization's overall safety, creating an environment that encourages raising safety concerns and management response, and leading the engagement of the PSEMS.

The five Regional Safety Directors are accountable for partnering with regional leaders and employees to identify region-specific hazards, assess risk, verify critical field controls, provide coaching on positive safety interactions, and coordinate the implementation of enterprise-wide workforce safety strategies.

4) Governance

PG&E's Board of Directors determined that its Safety and Nuclear Oversight Committee is responsible for overseeing the safety of the entire company. This committee will oversee and review company safety policies, practices, standards, and goals and address safety risks and compliance with related rules, standards, and regulations. The committee will also seek to improve safety practices and operational performance and promote and develop a strong safety culture.

5) Employee/Executive Compensation

PG&E's compensation policy is separated into two general categories, foundational compensation and at-risk compensation. Foundational compensation includes an employee's base pay, benefits, and pension. The proportion of foundational compensation to total compensation ranges from 13 to 100 percent for most represented employees to approximately 40 percent for PG&E officers. At-Risk compensation, or incentive compensation, is based on employee performance against set goals. The At-Risk category is separated into two plans that cover most of its employees and staff – the Short-Term Incentive Plan (STIP), and the Long-Term Incentive Plan (LTIP).

STIP

The STIP is an annually reviewed plan for salaried employees, hourly employees not represented by a labor agreement, and for represented salaried employees. It is a variable pay program tied to annual company performance. Participation rates vary by employee level, from 6 percent for support level employees to 30 percent for Senior-Director level staff.

LTIP

The LTIP is a program for Director-level and above positions. It is also a variable pay program tied to company performance, but it is reviewed over a more extended, three-year period. For 2024, LTIP awards comprised performance shares and/or a combination of performance and restricted stock. The awards are calculated based on Safety, Customer Experience, and Financial Stability performance. The Safety element covers two components - System Hardening Effectiveness and Electric Corrective Maintenance in High Fire Risk Areas. PG&E's Compensation Committee, and the independent members of its board, review and approve LTIP awards and have the discretion to reduce or eliminate an award.

Climate Resilience

For the 2024 RAMP, PG&E integrated Climate Adaptation and Vulnerability Assessment (CAVA) strategies into each risk chapter. Following the guidance in D.20-08-046, PG&E assessed its assets' vulnerability to climate change and adaptation capacity for each RAMP risk. PG&E's climate adaptation assessment study considered the 2030, 2050, and 2080 decadal time frames.

The following table in Figure 2 shows PG&E's CAVA climate risk rankings:

Line No.	Functional Area	Asset Families	High Heat	Heavy Rain /Flooding	Sea Level Rise	Wildfire
1	Electric	Transmission	Moderate	Moderate	Moderate	High
2	Electric	Substation	Moderate	Moderate	Moderate	Moderate
3	Electric	Distribution	High	Moderate	Moderate	High
4	Gas	Compression & Processing, Storage	Low	High	High	Moderate
5	Gas	Measurement and Control	Low	Moderate	Low	Low
6	Gas	Transmission Pipeline	Low	Moderate	Low	Low
7	Gas	Distribution Pipeline	Low	Moderate	Low	Moderate
8	Gas	LNG/CNG	Low	Low	Low	Low
9	Generation	Hydroelectric	Low	High (non-dam assets) Moderate (FERC high and significant hazard dams)	Not Applicable	High
10	Generation	Natural Gas	Low	Low	Low	Low
11	Generation	Solar	Low	Low	Low	Low
12	Generation	Nuclear	Low	Low	Low	Low
13	Facilities	Offices, yards, aviation, etc.	Low	Low	Low	Low
14	IT Assets	Data centers, fiber optic cable, etc.	Low	Low	Low	Low

Figure 2: Climate Adaptation Vulnerability Assessment Climate Risk Ranking

The table in Figure 3 below summarizes the adaptation options PG&E identified:

Line No.	Climate Hazard	Asset Family	CAVA Adaptation Options
1	Extreme Heat	Electric Transmission	1. Update temperature assumptions in maximum conductor loading calculations 2. Plan for climate-informed capacity projects 3. Implement real-time temperature conductor monitoring 4. Implement demand response and non-wires solutions
2	Extreme Heat	Electric Distribution	1. Incorporate forward-looking climate projections into load forecasts 2. Accelerate asset lifecycle replacement 3. Move vulnerable lines underground 4. Plan for climate-informed capacity projects 5. Implement demand response and non-wires solutions 6. Update line ratings 7. Reduce wind speed ratings 8. Transformer temperature sensors
3	Extreme Heat	Electric Substation	1. Provide additional cooling 2. Adopt updated design standards 3. Implement demand response and non-wires solutions 4. Plan for climate-informed capacity projects 5. Increase the safety margin in transformer loading 6. Provide additional monitoring 7. Increase the availability of mobile transformer and CEM units
4	Heavy Rain/ Flooding	Electric Transmission	1. Ensure climate-informed siting and design of new construction 2. Harden vulnerable structures 3. Develop emergency response plans
5	Heavy Rain/ Flooding	Electric Distribution	1. Further elevation of pad-mounted equipment 2. Accelerate/target replacement of live-front transformers with dead-front/submersible designs for pad-mount transformers 3. Increase targeted sectionalization
6	Heavy Rain/ Flooding	Electric Substation	1. Increase measures to prevent flooding 2. Improve drainage and pumping capacity 3. Install or improve pumping capacity 4. Elevate critical equipment 5. Implement waterproofing 6. Relocate vulnerable facilities 7. Temporary (deployable) flood barriers 8. Evaluation of regional collaboration partnerships
7	Heavy Rain/ Flooding	Natural Gas Compression & Processing, Storage	1. Incorporate low-probability flood events
8	Heavy Rain/ Flooding	Natural Gas Transmission Pipeline	1. System hardening

Figure 3: Climate Adaptation Vulnerability Assessment Adaptation Options

Line No.	Climate Hazard	Asset Family	CAVA Adaptation Options
9	Heavy Rain/ Flooding	Natural Gas Distribution Pipeline	1. Pipeline design measures to decrease risk of damage from ground displacement 2. Increased corrosion protection 3. Monitoring for landslide risk
10	Heavy Rain/ Flooding	Natural Gas Measurement & Control	1. Prioritized physical protection measures at stations in flood-prone areas 2. Relocate stations in flood-prone areas 3. Review vent heights for low-pressure stations located in floodplains 4. Continue to invest in system monitoring
11	Heavy Rain/ Flooding	Generation: Hydroelectric	1. Develop preliminary risk rating and identify vulnerable assets 2. System hardening 3. Enhanced hydrologic forecasting and monitoring 4. Enhanced monitoring of asset conditions
12	Sea Level Rise	Electric Transmission	1. Ensure climate-informed siting and design of new construction 2. Apply corrosion-resistant coatings 3. Harden vulnerable structures 4. Develop emergency response plans
13	Sea Level Rise	Electric Distribution	Refer to flooding and precipitation section for potential adaptation options.
14	Sea Level Rise	Electric Substation	Refer to flooding and precipitation section for potential adaptation options.
15	Sea Level Rise	Natural Gas Compression & Processing, Storage	Refer to flooding and precipitation section for potential adaptation options. 1. Incorporate sea level rise projections
16	Wildfire	Electric Transmission	No climate adaptation options are presented in the CAVA.
17	Wildfire	Electric Distribution	No climate adaptation options are presented in the CAVA.
18	Wildfire	Electric Substation	No climate adaptation options are presented in the CAVA.
19	Wildfire	Natural Gas Compression & Processing, Storage	No climate adaptation options are presented in the CAVA.
20	Wildfire	Natural Gas Measurement & Control	No climate adaptation options are presented in the CAVA.
21	Wildfire	Natural Gas Distribution Pipeline	1. Reducing the size of gas shutdown zones
22	Wildfire	Generation: Hydroelectric	1. Debris catchment basins and water conveyance carry-overs 2. Debris booms 3. Asset restoration

Figure 3: Climate Adaptation Vulnerability Assessment Adaptation Options (Continued)

Since PG&E considers the CAVA Adaptation Options within each risk chapter, any critical observations SPD has on each CAVA adaptation option or strategy are addressed within each risk chapter where appropriate.

Environmental and Social Justice Pilot Study and Implementation

ESJ Pilot Study Purpose

The purpose of PG&E's Environmental and Social Justice (ESJ) Pilot Study Plan (PSP) is to address the seven key action items directed in Decision (D.) 22-12-027[19] and provide insight into how PG&E's planned risk mitigations impact Disadvantaged Vulnerable Communities (DVC) relative to environmental and social justice.

Background and Introduction

Under the Phase 2 Decision of the Risk-Based Decision-Making Framework (RDF) Order Instituting Rulemaking (OIR, R.20-07-013), the four largest investor-owned energy utilities[20] (IOUs) were each directed to develop an ESJ pilot program as part of their next Risk Assessment Mitigation Phase (RAMP) filing. The decision identified seven action items to be included in the pilot study. Each IOU is to prepare an ESJ PSP. The purpose of the PSP is to ensure the IOU's risk assessments and risk mitigations address equity issues and the needs of the most vulnerable, specifically DVCs. The action items include addressing air pollution, climate resilience, and integrating ESJ into the RDF. The IOUs are required to consult with the Disadvantaged Communities Advisory Group (DACAG) and the Community-Based Organization Working Group (CBOWG) in developing the PSP.[21]

In June 2023, PG&E presented the ESJ PSP to the CBOWG and DACAG to receive feedback. In July 2023, PG&E hosted a public webinar to present each ESJ action item and requested stakeholder feedback. Building on this feedback, PG&E revised the PSP to support better integrating the ESJ pilot study into its 2024 RAMP filing. According to the PSP, PG&E's 2024 RAMP filing should identify potential equity issues that may disproportionately impact DVCs within its territory. Additionally, PG&E's PSP stated it would use the pilot to "better understand potential cumulative impacts of PG&E business decisions and to prioritize our actions to help support sustainable communities."[22]

These additional efforts allowed PG&E to identify Disadvantaged Communities (DAC) using GIS mapping tools. As a result, PG&E was able to identify low-income communities with less than 80 percent median income; as well groups within the CARB AB 617 DAC program, Tribal Trust Lands, DAC Top 25 percent

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[19] Phase II Decision (D.) 22-12-027 Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 (OIR 20-07-013) and Directing Environmental and Social Justice Pilots, December 15, 2022.
[20] Pacific Gas and Electric Company (PG&E), Southern California Gas Company, Southern California Edison Company, and San Diego Gas & Electric Company.
[21] D.22-12-027, OP 5.
[22] PG&E 2024 RAMP, Appendix A, ESJ Pilot Study Plan at App A-1.

CalEnviroScreen[23] 4.0, U.S. Department of Energy Disadvantaged Justice 40 Communities, Top 5 percent of Pollution Burden/Characteristics of CalEnviroScreen 4.0, U.S. Department of Transportation Justice 40 Disadvantaged Community, and Census Tract 2020/2010 using zip codes and county boundaries.

PG&E ESJ Actions Implementation

PG&E's ESJ pilot, submitted with its 2024 RAMP filing, addressed the seven ESJ action items directed in D.22-12-027, using the following approaches:

I. **Action Item #1:** *Consider equity in the evaluation of consequences and risk mitigation within the Risk-Based Decision-Making Framework (RDF), using the most current version of CalEnviroScreen to better understand how risks may disproportionately impact some communities.*

   Approach: PG&E's focus identifies risk impacts and equity in risk reduction in the DVC area based on three risks:

1. Loss of Containment on a Gas Transmission Pipeline (LOCTM)
2. Large Uncontrolled Water Release (LGUWR)
3. Wildfire Risk (WLDFR)

Observations:

SPD finds that PG&E adequately used these three risk areas to deliver and support resilience in low-income and disadvantaged communities in its service territory. SPD finds the following:

1. Loss of Containment on a Gas Transmission Pipeline (LOCTM)
   In its PSP, PG&E utilized CalEnviroScreen and GIS to configure the DVC areas impacted by LOCTM risk. Approximately 1,700 out of 6,500 miles of PG&E's gas transmission pipelines overlap with DVCs. In the pilot, PG&E developed a methodology to calculate the consequences, mitigation benefits, and total mitigation costs associated with DVCs. Each step was detailed in Exhibit PG&E-3, Chapter 1, Sec. B.8.a.[24] The Milage of Risk Exposure for DVC and non-DVC was estimated according to the 24 tranches used in the LOCTM chapter. Risk reduction and mitigation spending was estimated for mitigation and control programs across DVCs and non-DVCs. SPD's evaluation of PG&E's workpaper, GO-LOCTM-19_DVC analysis,[25] discovered a coding error in PG&E's estimate of natural units according to DVCs and non-DVCs. However, this error was found not to impact the estimate of risk reduction or NPV Spend for the mitigations proposed to be

[23] CalEnviroScreen is a mapping tool that helps identify California communities that are most affected by many sources of pollution, and where people are often especially vulnerable to pollution's effects. CalEnviroScreen uses environmental, health, and socioeconomic information to produce scores for every census tract in the state. The tool is developed by the California Office of Environmental Health Hazard Assessment (OEHHA). The tool is available at OEHHA's website at https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40.
[24] PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 1, page 1-21.
[25] Workpaper: Exhibit PG&E-3, Ch1 GO-LOCTM-19_DVC analysis.

implemented in the DVCs and non-DVCs.[26] In total, PG&E discovered that approximately 26.1 percent of the LOCTM risk is found within DVCs. PG&E has also targeted 28.1 percent of its investment in mitigations in DVCs, accounting for 28.4 percent of all risk reduction PG&E aims to achieve during this GRC cycle.[27]

The consequence of risk results can also be found in Exhibit PG&E-3, Chapter 1,[28] Table 1-7B in the 2024 RAMP Report. Using the tranche percentage approach, PG&E expects $686.3 million[29] to be spent on mitigations to reduce risk in the DVC area relative to the total $2,877.8 million spent on risk reduction, which is shown in Table 1-7C in the 2024 RAMP Report.

2. Large Uncontrolled Water Release (LGUWR)
   LGUWR was part of the study in ESJ PSP. The scope of this ESJ pilot was to identify which communities could be impacted by a potential dam breach. The dam breach inundation maps were overlayed with the ESJ CalEnviroScreen map as defined in D.22-12-02. Of the 60 dams included in LGUWR, PG&E identified 19 dams where the inundation zone could potentially impact DVCs. Exhibit PG&E-5, Chapter 1, Table 1-6[30] of the RAMP Report listed these dams. The total risk reduction for 2027-2030 was calculated for all controls and mitigations. PG&E stated it expects to spend $36.8 million in expenses and $1,065 million in capital on risk reduction for LGUWR. Of those totals, $7.5 million in expenses and $288.4 million in capital will be spent on dams in DVC areas. In its RAMP narrative and workpapers,[31] PG&E presented the safety consequences in natural units rather than the monetized attribute value as is required by D.22-12-027. SPD recommends that PG&E shouldpresent both the natural units and the monetized value of risk in its 2027 GRC filing and workpapers related to an ESJ analysis of the LGUWR risk event.

3. Wildfire Risk (WLDFR)
   As part of ESJ PSP efforts, PG&E mapped DVCs in its wildfire risk mapping tool and evaluated assets that fall under or overlap with DVC areas. SPD found that PG&E developed a methodology for determining the impact on DVCs as defined in D.22-12-027 and used this methodology to calculate the consequences, mitigation benefits, and total costs of mitigations associated with DVCs. In PG&E's distribution system, 42 wildfire risk tranches are aggregated into 20 tranches in Exhibit PG&E-4, Chapter 1, Table 1-15[32] of PG&E's RAMP Report. The risk analysis presented in Table 1-15 lacks key information necessary for understanding the implications of PG&E's mitigations and the impacts on DVCs. PG&E did not include subtotals for the HFRA and Non-HFRA percentage

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26 The coding error is located in the "Mileage, risk by DVC" tab in the GO-LOCTM-19_DVC analysis.xlsx workpaper, columns AB through AG.
27 For details see the "Summary" spreadsheet in the GO-LOCTM-19_DVC analysis.xlsx workpaper.
28 PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 1, pages 1-23 to 24.
29 PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 1, page 1-24, Lines 1-3 and page 1-25, Lines 1-2.
30 PG&E 2024 RAMP Report, Exhibit PG&E-5, Chapter 1, page 1-35, Lines 12-18.
31 Workpaper: Exhibit PG&E-5, Ch1 Gen-LGUWR Confidential.
32 PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 1, pages 1-43 to 44, Lines 20-26.

of DVC Customers, Baseline Wildfire Risk, DVC Risk, Non-DVC Risk and percentage DVC Risk. Moreover, PG&E's study should emphasize that the HFRA shows significant differences between the population density of DVC Customers and the percentage of risk faced by the DVCs. SPD provides the following analysis based on this lack of information in either PG&E's narrative or workpapers in the RAMP:

Table ESJ-1: Subtotals of Risk within Wildfire Tranches by DVC and Non-DVC

Distribution Tranche Group	Customers	% DVC Customers	Total Risk	DVC Risk	Non-DVC Risk	% DVC Risk
HFRA - Distribution - Tranche 1	7,158	23%	786	226	560	29%
HFRA - Distribution - Tranche 2	11,498	18%	808	210	599	26%
HFRA - Distribution - Tranche 3	10,885	35%	1,530	638	892	42%
HFRA - Distribution - Tranche 4	13,774	32%	1,896	740	1,155	39%
HFRA - Distribution - Tranche 5	13,826	28%	1,959	709	1,250	36%
HFRA - Distribution - Tranche 6	18,463	31%	1,843	641	1,202	35%
HFRA - Distribution - Tranche 7	25,082	20%	1,899	529	1,370	28%
HFRA - Distribution - Tranche 8	40,960	22%	1,930	593	1,337	31%
HFRA - Distribution - Tranche 9	73,290	15%	1,946	414	1,532	21%
HFRA - Distribution - Tranche 10	290,911	13%	1,709	338	1,371	20%
non-HFRA - Distribution - Tranche 1	23	87%	12	3	9	23%
non-HFRA - Distribution - Tranche 2	311	3%	21	2	19	10%
non-HFRA - Distribution - Tranche 3	468	64%	25	7	18	29%
non-HFRA - Distribution - Tranche 4	1,062	27%	25	8	18	30%
non-HFRA - Distribution - Tranche 5	522	17%	17	6	11	35%

Distribution Tranche Group	Customers	% DVC Customers	Total Risk	DVC Risk	Non-DVC Risk	% DVC Risk
non-HFRA - Distribution - Tranche 6	2,856	56%	36	13	23	36%
non-HFRA - Distribution - Tranche 7	2,642	39%	33	9	24	27%
non-HFRA - Distribution - Tranche 8	9,743	21%	32	10	22	31%
non-HFRA - Distribution - Tranche 9	22,385	16%	58	12	45	21%
non-HFRA - Distribution - Tranche 10	4,909,133	31%	276	112	164	41%
Grand Total	5,454,992	29%	16,841	5,222	11,619	31%
HFRA Total	505,847	16%	16,306	5,040	11,266	31%
Non-HFRA Total	4,949,145	31%	535	182	353	34%

The implications of Table ESJ-1 are important to highlight. Within PG&E's HFRA, of the 505,847 customers, 16 percent live within a DVC, which was similarly demonstrated in TURN's Informal Comments.[33] These HFRA/DVC customers face a disproportionate amount of wildfire risk (31 percent). Additionally, PG&E's current narrative presented an "Overall Total" or "Grand Total" that could be misleading.[34]

To mitigate WLDFR risks, two programs can support and benefit disadvantaged communities: 1) Public Safety Power Shutoffs (PSPS) and Enhanced Power Line Safety Settings (EPSS) and 2) System Hardening.

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[33] Informal Comments of The Utility Reform Network (TURN) on PG&E's RAMP Report, October 9, 2024, at 28.

[34] Specifically, in PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 1, Table 1-16 and Table 1-17 Line 11 "Overall Total" should be labeled "HFRA Subtotal" and the Percentage of DVC Customer should be properly updated. Additionally, in PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 1, Table 1-18, Line 6 "Grand Total" should be labeled "System Hardening Subtotal" and the Percentage of DVC Customer should be properly updated.

1) PSPS and EPSS

The PSPS and EPSS mitigations in targeted HFTD/HFRA locations are included in Table 1-16[35] of PG&E's RAMP Report. The benefits of PSPS and EPSS are calculated based on wildfire risk reduction. The yearly DVC reliability impacts of PSPS and EPSS outcomes were stipulated in Table 1-17[36] of the RAMP Report. PG&E anticipates a 30 percent risk reduction will occur in DVCs through the use of PSPS and EPSS. PG&E notes that the allocation of PSPS and EPSS consequences was done proportionally to DVC customers in each tranche but does not provide an explanation. SPD recommends that PG&E explain in its 2027 GRC filing how allocating these consequences proportionally to DVC customers within each tranche is appropriately data-supported, and how this approach is related to PG&E's estimation of the reliability attribute via the Interruption Cost Estimator (ICE) calculation.

2) System Hardening

PG&E primarily focuses on wildfire HFTD/HFRA locations for system hardening. Table 1-18[37] of the RAMP Report stipulated five tranches. The DVC wildfire benefits or risk reduction from system hardening is about 39 percent. PG&E estimated a cost of $2 billion, or 31 percent, spent on system hardening to mitigate wildfire risk for the period of 2027-2030.

II. **Action Item #2:** *Consider investments in clean energy resources in the RDF as possible means to improve safety and reliability and mitigate risks in DVCs.*

Approach: Identify methods to improve the risk reduction benefits of the Microgrid Incentive Program (MIP) and Community Microgrid Enablement Program (CMEP) to bring clean energy to DVC areas.

Observations:

SPD found that PG&E utilized two microgrid programs: 1) Microgrid Incentive Program (MIP) and 2) Community Microgrid Enablement Program (CMEP).

MIP's objective is to provide advanced technology for climate resiliency and equitably distribute the benefits of microgrids to DVCs for public health, safety, and welfare. PG&E budgeted and funded the program for $79.2 million. Currently, PG&E is working with community applicants to award the funding. The awardees will work with PG&E to develop microgrids on PG&E's distribution system.

PG&E's CMEP is designed to assist with qualifying projects in areas with the greatest resilience needs for multiple customers. The CPUC approved the program, which provides up to $3 million per project in cost offsets for equipment to enable safe microgrids, such as isolation devices, undergrounding, and microgrid controllers. The CMEP is mainly available to DVCs vulnerable to power outages in the PG&E's service area

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35 PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 1, page 1-45.
36 PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 1, page 1-45.
37 PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 1, page 1-46, Lines 10-13.

and will provide energy resilience. Microgrid programs work in conjunction with DVC communities to provide clean energy resources.

PG&E states both programs are incorporated to improve safety and reliability and to mitigate risk in DVCs. However, no evidence is provided that either program has a quantifiable impact on safety and/or reliability for any risks presented in the 2024 RAMP filing. For example, PG&E cites to D.21-01-018 that notes microgrids can alleviate inequality for counties hardest hit by climate change but does not clarify how this translates into risk reduction in DVCs that face risk events presented in the 2024 RAMP. SPD recommends that PG&E explain in the Test Year 2027 GRC how these two microgrid programs translate into improvements in safety and reliability for DVCs facing risk events presented in the 2024 RAMP.

III. **Action Item #3:** *Consider Mitigations that improve local air quality and public health in the RDF, including supporting data collection efforts associated with Assembly Bill 617 regarding community air protection program.*

Approach: According to RDF, PG&E focuses on integrating research and ongoing developments directed in Assembly Bill (AB) 617[38] in its 2024 RAMP. PG&E also provides details on reducing greenhouse gas (GHG) emissions, including local air pollutants, to improve public health.

Observations:

SPD identified that, since 2017, PG&E has been actively engaged in developing and implementing AB 617 in collaboration with the California Air Resources Board (CARB) and other stakeholders. PG&E plans to implement community air pollution protection programs to effectively reduce emissions in disadvantaged communities and improve public health in the surrounding regions. PG&E also stated it could not provide any deliverables associated with mitigations for reducing GHG emissions and local air pollution data to the 2024 RAMP Report as discussions continue with CARB and other stakeholders. Further, PG&E stated it is working with nine AB 617 and ESJ communities and providing grants to community-based organizations. However, the RAMP report did not clearly identify these programs with quantifiable risk-mitigation information. SPD recommends that PG&E explain in the Test Year 2027 GRC why mitigation for GHG emissions and local air pollutants programs have yet to be implemented.

IV. **Action Item #4:** *Evaluate how the selection of proposed mitigations may impact climate resilience in DVCs.*

Approach: PG&E aims to mitigate climate-related risks and establish climate resiliency relevant to DVCs. It also gathers information through its community outreach process initiative and explains it in the 2024 RAMP report.

Observations:

PG&E's response to Action Item #4 is in line with PG&E's 2024 Climate Adaptation and Vulnerability Assessment[39] (CAVA), which was submitted parallel to its 2024 RAMP filing. Following a detailed analysis and discussion in its CAVA filing, PG&E states it will ensure that its electrical system is protected and that

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[38] Assembly Bill (AB) 617: Nonvehicular air pollution, criteria air pollutants and toxic air contaminants, July 26, 2017.

[39] PG&E Climate Adaptation and Vulnerability Assessment Report, May 15, 2024. For details, see D.20-08-046.

communities have safe, reliable, resilient energy systems. Details were dispersed intermittently through the 2024 RAMP filing as a cross-cutting climate change factor. In the LGUWR risk chapter, PG&E did not attempt to model the impact of climate change on dam safety.[40] PG&E did not discuss how the mitigations to reduce the likelihood of an LGUWR risk event would impact climate resilience in DVCs. In the Wildfire risk chapter, PG&E provides limited discussion of how a climate change factor was quantitatively integrated into the risk models. However, there is no presentation in the narrative or workpapers of how mitigations, such as System Hardening, would impact climate resilience in DVCs. SPD recommends that PG&E provide a clear quantitative analysis in its 2027 GRC filing on how mitigations will impact climate resilience in DVCs. Additionally, SPD recommends PG&E quantitatively clarify the relationship between mitigations presented in the 2027 GRC and climate resilience in DVCs in its upcoming Climate Pilot White Paper (due September 15, 2025, as ordered in D.24-05-064).

V. **Action Item #5:** *Evaluate if the estimated impacts of wildfire smoke included in the RDF disproportionately impact DVCs.*

Approach: PG&E aims to identify if DVCs are disproportionately impacted by wildfire smoke. In addition to broader studies, it plans to integrate wildfire smoke analysis methodologies for evaluation.

Observations:

Most of PG&E's discussion relates to the 2022 CARB Scoping Plan.[41] It is unclear whether PG&E also reviewed any research conducted through CARB funding on the health impacts of exposure to wildfire smoke.[42]. PG&E also presented two academic articles that claimed more information is needed about the health effects of wildfire smoke. From its this review, PG&E concluded:[43]

- CARB's Scoping Plan does not include any conclusions on the impact of wildfire smoke on DVCs;
- CARB asserts that DVCs experience greater exposure to PM2.5[44] pollution from all sources without identifying wildfire smoke as a significant contributor; and
- There is consensus in other public studies that wildfire smoke impacts generally require further study.

Overall, it is unclear why PG&E did not address some of the widely available research on this topic that is directly related to DVCs in California. The health impacts of wildfire smoke on Californians are well

[40] PG&E 2024 RAMP Report, Exhibit PG&E-5, Chapter 1 at 1-33

[41] California Air Resources Board (CARB) Scoping Plan, December 2022.

[42] More details can be found here https://ww2.arb.ca.gov/resources/documents/examining-health-impacts-short-term-repeated-exposure-wildfire-smoke

[43] PG&E 2024 RAMP Report, Exhibit PG&E-2, Chapter 7, page 7-21.

[44] PM 2.5 stands for atmospheric particulate matter that consists of fine particles less than **2.5** micrometers in diameter.

documented.[45] Moreover, widespread evidence shows that DVC residents face the health impacts of wildfire smoke near their homes and where they work.[46] This ESJ Pilot was an opportunity for PG&E to present a rigorous and novel approach to addressing this issue, but it did not do so in its 2024 RAMP filing. In comparison, San Diego Gas & Electric (SDG&E) has already utilized the measure of "acres burned" as a proxy for estimating wildfire smoke in its 2021 RAMP filing, which has been discussed repeatedly by MGRA.[47] While this approach is not all-encompassing, SPD agrees with MGRA and recommends that PG&E adopt SDG&E's "acres burned" as an interim proxy for estimating the impact of wildfire smoke on DVCs in PG&E's 2027 GRC filing.

VI. **Action Item #6:** *Estimate the extent to which risk mitigation investments included in the RDF impact and benefit DVCs independently and in relation to non-DVCs in the IOU service territory.*

Approach: PG&E aims to use the risk analysis in Action Item #1 and compare the impacts and benefits relative to DVC and non-DVC communities using census tracts to implement mitigations.

1. Loss of Containment on a Gas Transmission Pipeline (LOCTM)
2. Large Uncontrolled Water Release (LGUWR)
3. Wildfire Risk (WLDFR)

Observations:

Action Items #1 and #6 discuss the ESJ PSP. SPD found that PG&E developed plans on the above three risk areas to deliver and support resilience in low-income and disadvantaged communities in its service territory. SPD's findings for Action Item #6 are similar to those discussed in Action Item #1. However, one finding is specific to Action Item #6. After PG&E completed its analysis of mitigation investments' impact on the LOCTM, LGUWR, and Wildfire risks in DVCs and Non-DVCs, it only presented NPV Benefits and NPV Costs. It is unclear why PG&E did not complete the analysis to include a CBR calculation for all mitigation programs across the DVCs and Non-DVCs. SPD recommends that PG&E include CBR calculations for all LOCTM, LGUWR, and Wildfire mitigation programs in DVCs and Non-DVCs.

VII. **Action Item #7:** *Enhance outreach and public participation opportunities for DVCs to meaningfully participate in risk mitigation and climate adaptation activities consistent with Decision 20-08-046.*

Approach: PG&E plans to provide a CAVA and a Community Engagement Plan (CEP), as well as publicly notice a workshop for the CEP. PG&E also plans to seek community input to understand

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[45] Heaney, Alexandra, Jennifer D. Stowell, Jia Coco Liu, Rupa Basu, Miriam Marlier, and Patrick Kinney. "Impacts of fine particulate matter from wildfire smoke on respiratory and cardiovascular health in California." *GeoHealth* 6, no. 6 (2022): e2021GH000578.

[46] Chunga Pizarro, Carlo A., Rebecca R. Buchholz, Rebecca S. Hornbrook, Kevin Christensen, and Michael Méndez. "Air quality monitoring and the safety of farmworkers in wildfire mandatory evacuation zones." *GeoHealth* 8, no. 7 (2024): e2024GH001033.

[47] For details, see Mussey Grade Road Alliance (MGRA) Informal Comments to the Safety Policy Division Regarding Pacific Gas and Electric Company's RAMP Filing (Revision 1), October 11 2024 at 29 and Mussey Grade Road Alliance Protest on SDG&E's 2021 RAMP Application, June 9, 2021 at 11-12.

potential impacts and host public workshops for the ESJ pilots, its implementation, and explanations of PG&E's RAMP.

Observations:

SPD identified that PG&E submitted its community engagement plan in May 2023, and its CAVA was filed in May 2024. In addition, PG&E hosted public workshops for the Pre-RAMP (risk selection and scaling) and Cost-Benefit Approach, including the Risk Model Framework, in February and April 2024, respectively. The feedback PG&E received was presented in Exhibit PG&E-2, Table 7-3 of the RAMP Report.[48]

Climate Adaptation and Vulnerability Assessment

PG&E filed its CAVA report simultaneously with its RAMP filing in May 2024. CAVA has an integral role in evaluating the ESJ pilot. It focuses on the long-term vulnerabilities of PG&E's assets and infrastructures to climate change for 2030, 2050, and 2080. As part of the CAVA report filing, PG&E also submitted the *Resilient Together Initiative* community engagement plan for its service territory. The CPUC's Energy Division is leading the effort on CAVA based on D.20-08-046[49] and D.19-10-054[50] for PG&E compliance.

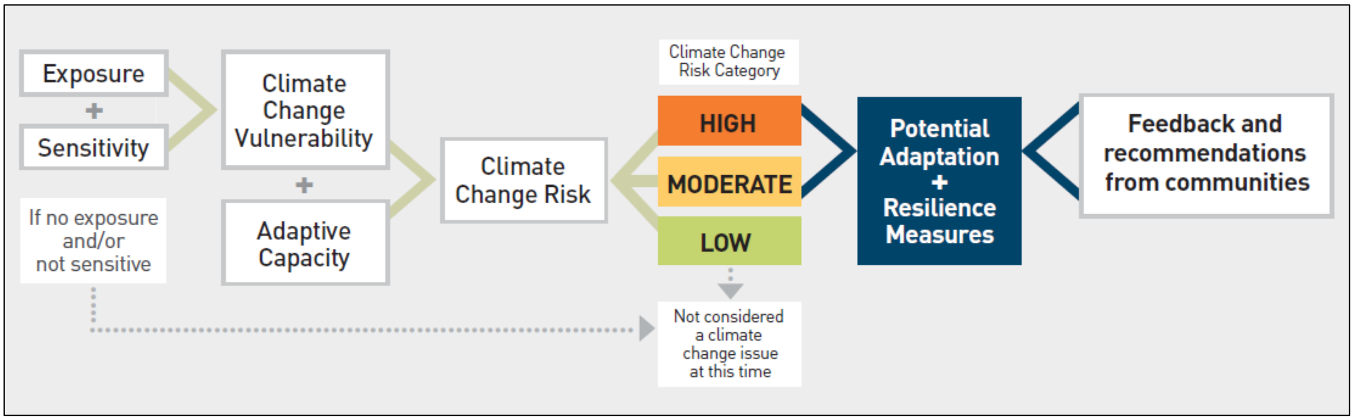
Predominantly, CAVA encompasses how climate change, such as extreme heat and temperatures, droughts, storms, flooding, landslides, sea level rise, and wildfires impacts PG&E's assets and ability to provide safe and reliable service. In the 2020 RAMP, climate change was considered a CCF. In the 2024 RAMP[51], PG&E made improvements the areas of: 1) recent climate projection data used, 2) granularity at which climate data are incorporated into the modeling, and 3) integration of the relationship between climate change and degradation in assets.

Methodology:

PG&E utilized the following methodology to include a range of climate vulnerability, directed in D.20-08-046, as illustrated in Figure ESJ-1 below. The CAVA assessment encompasses exposure, sensitivity, and adaptive capacity to evaluate the climate change risk to PG&E's assets and infrastructure, along with potential vulnerabilities affecting operations and service areas.

[48] PG&E 2024 RAMP Report, Exhibit PG&E-2, Chapter 7, at 7-27.
[49] D.20-08-046 Decision on Energy Utility Climate Change Vulnerability Assessments (CAVA) and Climate Adaptation in Disadvantaged Communities (Phase I, Topics 4 and 5), August 27, 2020.
[50] D.19-10-054 Decision on Energy Utility Climate Change Vulnerability Assessments (CAVA) and Climate Adaptation in Disadvantaged Communities (Phase I, Topics 1 and 2), October 24, 2019.
[51] PG&E 2024 RAMP Report, Exhibit PG&E-2, Chapter 3, at 3-17, Lines 5-8.

Figure ESJ-1. Vulnerability Assessment Framework[52]



CAVA Key Findings:

The findings show PG&E's asset vulnerability to climate-related impacts for 2050 and beyond. PG&E determined to make strategic investments to protect and strengthen its energy system from climate-related risks. Below are SPD's findings from a review of the CAVA report and Figure ESJ-2 below.

1. High temperatures and heat waves may impact operational capabilities to achieve grid resiliency and future climate goals, ultimately reducing equipment life and electrical asset failure to diminish reliability.
2. Flooding, sea level rise, and precipitation may severely impact electric and gas assets in coastal areas, including substations. Additionally, non-dam hydropower facilities may be damaged.
3. The impacts of climate change may increase the risk of wildfires damaging PG&E's assets and resulting in PG&E's critical operations. The continuous efforts of the wildfire mitigation plan primarily focus on mitigating wildfire risk to protect equipment and enhance climate resilience.

[52] PG&E Climate Adaptation and Vulnerability Assessment Report, May 2024, page Introduction 1-4.

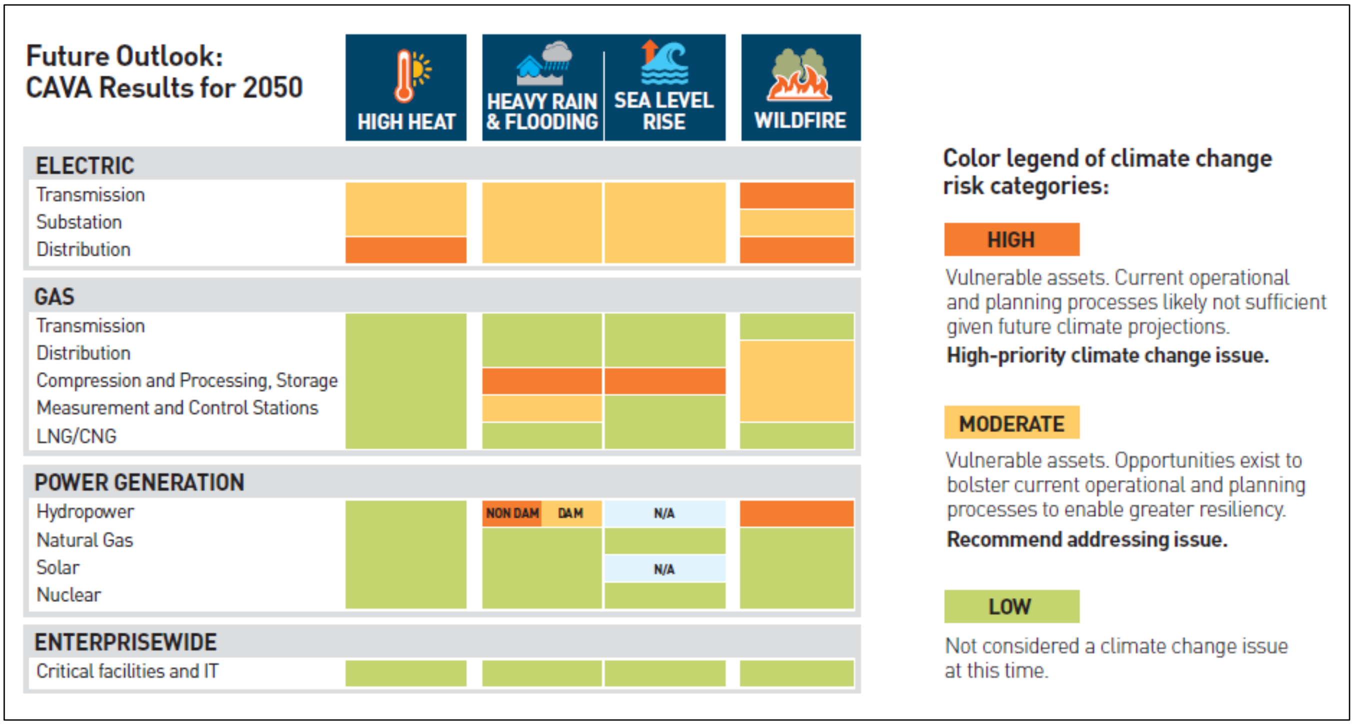


Figure ESJ-2. Climate Change Risk Categories of PG&E's Assets[53]

Observations:

The CAVA report offers a prioritized assessment of climate vulnerability, emphasizing the viewpoints of climate-vulnerable communities. Fundamentally, it establishes a foundation for climate-conscious planning and collaboratively building resilient infrastructure. Through the *Resilient Together Initiative*, DVCs identified affordability and reliability as their primary concerns for PG&E to prioritize. Furthermore, PG&E should reduce gaps among DVC customers to meet the needs of existing program goals. Further engagement and effort is needed on CAVA, energy sectors, community preferences, local and tribal governments, and equity considerations for climate adaptation. SPD observed that PG&E did not integrate CBR calculations for climate change, as PG&E claims that it still considers this a foundational activity, not a risk-reducing program.[54] Finally, SPD recommends that PG&E explain its short- and long-term climate investment strategy and capital investment plan in its 2027 GRC filing.

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[53] PG&E Climate Adaptation and Vulnerability Assessment Report, May 2024, page Introduction 1-17.
[54] PG&E Climate Adaptation and Vulnerability Assessment Report, May 2024.

ESJ Pilot Summary and Recommendations

PG&E generally complied with the directives in D.22-12-027 in developing its plan to mitigate risks associated with the environmental and social justice communities and address potential equity issues. SPD observed that PG&E has partially addressed the seven action items in the pilot study program, but improvement is still needed.

SPD summarizes the following recommendations related to PG&E's ESJ Pilot. SPD recommends that in the Test Year 2027 GRC:

1. PG&E present both the natural units and the monetized value of risk in its RAMP narrative and workpapers related to an ESJ analysis of the LGUWR risk event.
2. PG&E incorporate HFRA and Non-HFRA subtotals into its overall risk assessment and explain why DVC communities face a disproportionate amount of wildfire risk in its 2027 GRC filing.
3. PG&E update Tables 1-15, 1-16, 1-17, and 1-18 in the Wildfire chapter of the PG&E RAMP Report with appropriate subtotals to better reflect the analysis presented.
4. PG&E provide an explanation why allocating PSPS and EPSS consequences proportionally to DVC customers within each tranche is an appropriately data-supported approach and how this approach is related to PG&E's estimation of the reliability attribute via the ICE calculator.
5. PG&E explain how the two microgrid programs (MIP and CMEP) translate into improvements in safety and reliability for DVCs facing risk events presented in the 2024 RAMP.
6. PG&E clearly explain why it and other AB 617 stakeholders have yet to decide on mitigation for GHG emissions and local air pollutants.
7. PG&E provide a clear quantitative analysis for how mitigations will impact climate resilience in DVCs.
8. PG&E quantitatively clarify the relationship between mitigations presented in the 2027 GRC filing and climate resilience in DVCs in its upcoming Climate Pilot White Paper (due September 15, 2025, as ordered in D.24-05-064).
9. PG&E adopt SDG&E's "acres burned" method as an interim proxy for estimating the impact of wildfire smoke on DVCs.
10. PG&E include CBR calculations for all LOCTM, LGUWR, and wildfire mitigation programs in DVCs and Non-DVCs.
11. PG&E explain its short—and long-term climate investment strategy and capital investment plan.

Evaluation of Risk Chapters

1. Wildfire with PSPS and EPSS

Risk Description

Approximately 53 percent of fires that occurred in PG&E's service territory lie in High Fire Threat District (HFTD) areas. Given that the Wildfire Risk is predominantly concentrated in HFTD areas, PG&E has focused its mitigation efforts by reassessing the HFTD annually and creating a High Fire Risk Area (HFRA) zone that includes HFTD and select non-HFTD areas. PG&E's Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment, originating from PG&E assets or activities.

Wildfire Risk with Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) accounts for the benefits and consequences of operational mitigations when PSPS and EPSS are implemented. PSPS and EPSS are two key operational mitigation programs that provide weather-driven response to forecasted fire danger. Due to its significant potential disruption to electricity delivery and the resulting safety impacts, PSPS is considered a mitigation measure of last resort. Conversely, EPSS is a protective strategy that allows line protection devices, such as line reclosers, to respond more rapidly to the need to de-energize lines. EPSS generally has less negative impact on reliability and indirect safety consequences than PSPS because PSPS pre-emptively de-energizes a circuit *regardless* of whether there is a fault condition, whereas EPSS activates to de-energize the circuit *only* when a fault condition is detected.

PG&E's Meteorology team has developed a Fire Potential Index (FPI) Model that combines fire weather parameters (wind speed, temperature, and vapor pressure deficit), dead and live fuel moisture data, topography, and fuel model data to predict the probability of large and/or catastrophic fires. The index, ranging from R1 to R5+, provides forward-looking insight to guide the implementation of utility operational mitigations. Table 1-1 shows the risk definition and Figure 1-1 shows PSPS and EPSS deployment as a function of FPI and ignition probability.

Table 1-1: Risk Definition and Scope

WILDFIRE RISK WITH PSPS AND EPSS	
Definition	The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment originating from PG&E assets or activities. In the near term due to the use of PSPS and EPSS we have also defined Post PSPS/EPSS Wildfire Risk as Wildfire Risk with PSPS and EPSS. This does account for the benefits and consequences of operational mitigations such as PSPS and EPSS
In Scope	2015 to 2022 PG&E recorded ignition record (CPUC reportable and non-reportable). Other PG&E failure events (e.g., equipment failure without ignition, outage, etc.)
Out of Scope	Fire ignitions and associated impacts not related to PG&E electric system assets.
Data Quantification Sources	PG&E sourced ignitions, CAL FIRE, National Weather Service (NWS), other PG&E data (Outage data, Geographic Information System data, PG&E System Earthquake Risk Assessment (SERA) model, Integrated Logging Information Systems, Transmission Operation Tracking and Logging), Fire Weather Index, WDRM_V3 model outputs, EPSS Outage dataset, Technosylva population impacted, PSPS damages and hazards assessment.

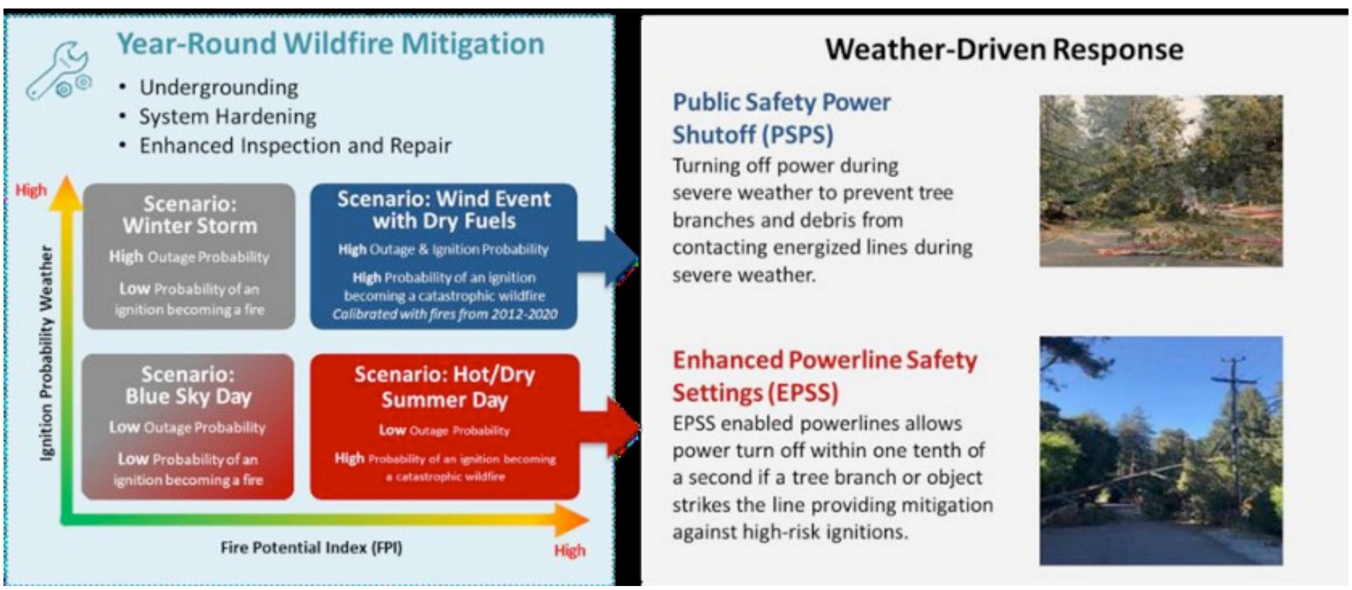

Figure 1-1: Weather-driven response to forecasted fire danger[55]

Excluding operational mitigations, the 2027 Baseline Wildfire Risk is $19.633 billion (in 2023 dollars). With operational mitigations, the 2027 Test Year (TY) Wildfire + PSPS + EPSS Total Net Residual Risk Value is

[55] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Figure 1-1

$7.666 billion (in 2023 dollars). PG&E is projecting an approximate 11 percent risk increase due to climate change by the beginning of 2027 and another 7 percent increase from 2027 to 2030. This baseline risk is offset by an approximate 21 percent and 22 percent decrease attributed to PG&E's permanent mitigations between 2023-2026 and 2027-2030, respectively, largely driven by PG&E System Hardening programs. The result is a net 11 percent risk reduction by the start of 2027 and another 15 percent reduction from 2027 to 2030. Figure 1-2 shows the baseline risk evaluated at the beginning of TY 2027 for both the "with" and "without" PSPS and EPSS scenarios.

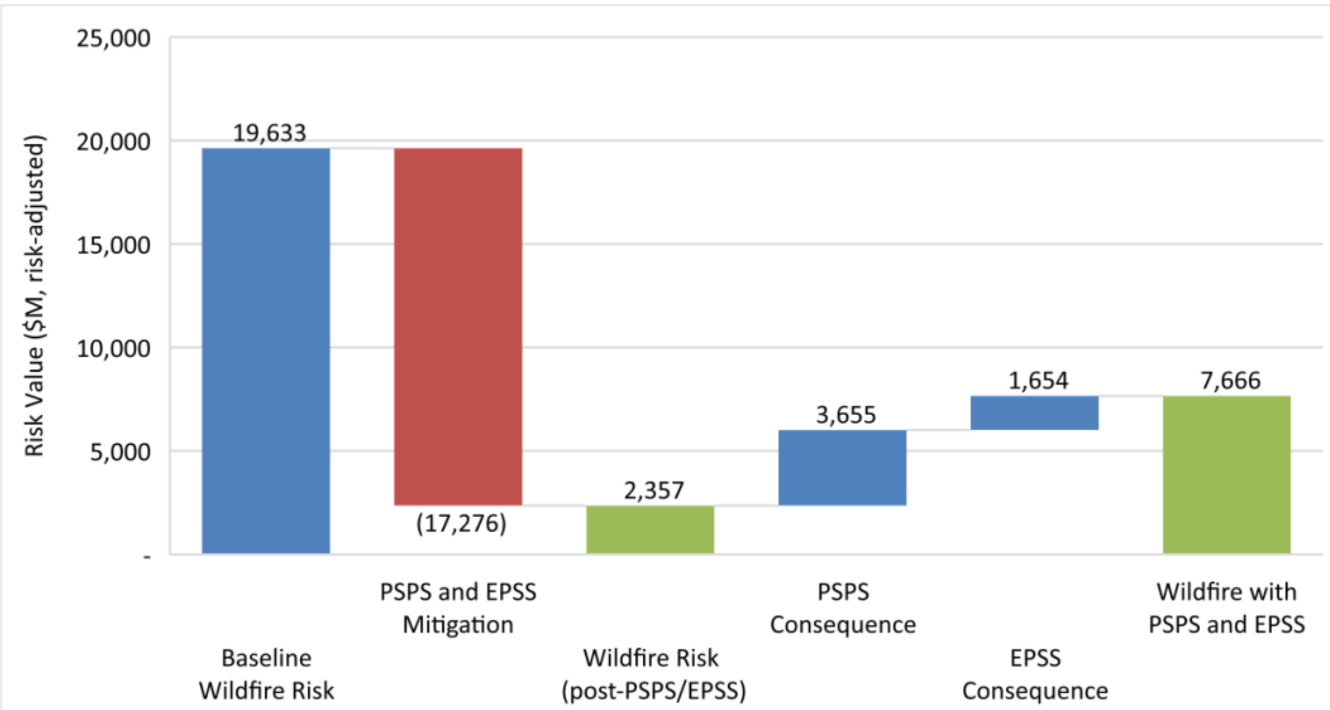

Figure 1-2: TY 2027 Baseline Risk (with and without operational mitigations)[56,57]

PG&E's Wildfire Distribution Risk Model (WDRM) breaks down its system into approximately 11,000 circuit segments, with approximately 3,600 circuit segments located in HFTD/HFRA. Figure 1-3 shows that the cumulative risk reduction and the cumulative miles of risk mitigation activity are negatively correlated in a non-linear manner. Figure 1-3 below is commonly referred to as a "risk buy-down curve," and shows the typical diminishing return characteristic of risk mitigation activities. The risk buy-down curve in Figure 1-3 shows that more than 80 percent of PG&E's wildfire risk is represented by the first 10,000 highest-risk overhead circuit miles. As risk mitigation activities progress beyond that point, the flattening of the risk buy-

[56] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Figure 1-2

[57] Dollar figures are in 2023 dollars.

down curve shows a sharp decrease in risk reduction. In Figure 1-3, the horizontal lines divide PG&E's primary overhead HFTD risk into 10 tranches. Each tranche (decile) represents approximately 10 percent of the wildfire distribution risk associated with PG&E's primary overhead line miles in HFTD areas. Ultimately, work activities in the higher end (i.e., the upper left side) of the risk buy-down curve will result in a greater risk reduction benefits and higher cost-benefit ratios.

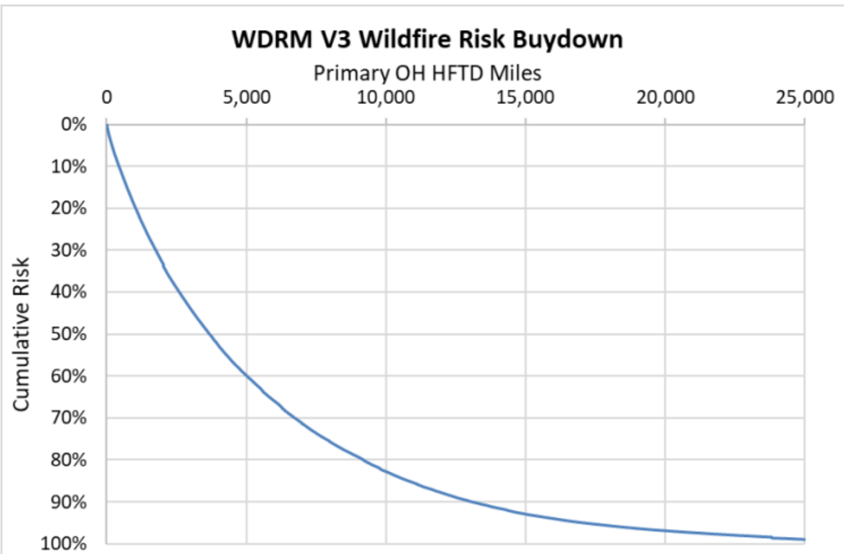

Figure 1-3: Relationship between cumulative wildfire risk reduction and cumulative circuit miles of risk reduction activity[58]

Observations:

Figure 1-3 is plotted based on the Baseline Data spreadsheet in the "EO-WLDFR-18 WDRM V3 Risk Buydown.xlsx" workpaper. PG&E provides risk scores calculated using WDRM V3[59] for each circuit segment but does not clearly explain how it assigned circuit segments to risk-based tranches. SPD created Table 1-2 below with selected circuit segments to highlight this issue. SPD calculated the risk-per-mile (risk/mile) values using PG&E's risk and mileage data.[60] As shown in Table 1-2 below, SPD finds no discernable correlation between the risk/mile values and PG&E's assigned tranches. SPD provides more detailed analyses on this issue in the Tranche observations section.

[58] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Figure 1-11.

[59] Version 3.

[60] Workpapers EO-WLDFR-18 WDRM V3 Risk Buydown.xlsx (tab "Baseline Data") and EO-WLDFR-M002_System_Hardening_OH.xlsx (tab, "IN6_WLDFR_Tranches").

Table 1-2: Discrepancies in Risk buy-down data and tranche assignments

Circuit Segment	Feeder Name	Total WDRM V3 Risk	Primary Overhead HFTD Mileage	Risk per mile	PG&E Assigned Tranche
PINE GROVE 1101CB	PINE GROVE 1101	3.403	4.275	0.796	1
MONTICELLO 1101630	MONTICELLO 1101	3.840	4.324	0.888	1
MARIPOSA 2102594143	MARIPOSA 2102	0.709	0.540	1.313	6
SILVERADO 21051306	SILVERADO 2105	0.512	0.571	0.897	7
LAYTONVILLE 1101518	LAYTONVILLE 1101	1.717	2.102	0.817	8
ALLEGHANY 1101VR816	ALLEGHANY 1101	1.2	4.097	0.29	7
SHADY GLEN 110248894	SHADY GLEN 1102	4.00	10.13	0.39	2

Bow Tie

PG&E created several Bow Tie and risk scenarios to demonstrate: (1) PG&E's TY 2027 Baseline Wildfire Risk, the risk without utilization of PSPS and EPSS operational mitigations, (2) Post-PSPS/EPSS Wildfire Risk, what PG&E customers experience "day-to-day" not including the reliability and indirect safety consequences resulting from the deployment of PSPS and EPSS, (3) PSPS Consequence, negative impact of PSPS, (4) EPSS Consequence, negative impact of EPSS, and (5) Wildfire with PSPS and EPSS, the net resulting wildfire risk after accounting for both the risk reduction benefits and negative consequences of PSPS and EPSS.

To summarize these scenarios, PG&E forecasts that (1) PG&E's Baseline Wildfire Risk for 2027 will have a monetized risk value of $19.6 billion, (2) Post-PSPS/EPSS Wildfire Risk for 2027 will have a monetized risk value of 2.36 billion, (3) PSPS Consequence will have a monetized risk value of $3.6 billion, (4) EPSS Consequence will have a monetized risk value of $1.65 billion, and (5) Wildfire with PSPS and EPSS will have a monetized risk value of $7.67 billion, after accounting for benefits and negative consequences of PSPS and EPSS. All monetized risk values are represented in 2023 dollars. The 2024 RAMP includes independent modeling of the PSPS risk and the impacts of EPSS. This more detailed presentation, that includes PSPS and EPSS, differs from the simpler risk Bow Tie models presented in the 2020 RAMP and TY2023 GRC.

In the Bow Tie analyses for Wildfire and PSPS/EPSS, PG&E describes 10 drivers (See PG&E-4 Table 1-7, further explained later in the Driver section). PG&E also lists eight outcomes separated between Red Flag

Warning (RFW) outcomes and Non-RFW outcomes. The risk value in each Bow Tie is calculated by the aggregated frequency of drivers (events/year) multiplied by the aggregated CoRE.[61]

Observations: None.

Exposure

Wildfire Exposure

Wildfire risk exposure is measured in circuit miles, with approximately 222,000 miles across PG&E's electric distribution and transmission systems. Figure 1-4 shows that 20.9 percent of PG&E's wildfire ignitions occur in HFTD and HFRA locations. The HFTD/HFRAs include 48,429 miles (or 21.8 percent of PG&E's total wildfire risk exposure) and account for 97 percent of PG&E's overall wildfire risk. PG&E's wildfire exposure mileage includes low voltage Secondary and Service overhead (OH) lines.

Additionally, 77 percent of the total wildfire risk is concentrated within PG&E's Primary Distribution system (total of Primary UG and Primary OH).

Line No.	Asset Class	Asset System	Total Exposure (Miles)	HFTD/HFRA (Miles)	% HFTD/HFRA Exposure	% Ignitions in HFTD/HFRA	% WF Risk in HFTD/HFRA
1	Distribution	UG	28,498	3,027	11%	0.2%	1%
2	Distribution	Primary OH	80,815	25,935	32%	17.3%	76%
3	Distribution	Secondary OH	16,157	2,771	17%	1.1%	3%
4	Distribution	Service OH	78,754	11,036	14%	1.0%	4%
5	Transmission	60/70 kilovolt (kV)	5,361	1,812	34%	0.7%	7%
6	Transmission	115 kV	5,942	1,737	29%	0.4%	5%
7	Transmission	230/500 kV	6,683	2,111	32%	0.1%	1%
8	Total		222,209	48,429		20.9%	97%

Figure 1-4: PG&E system wildfire exposure (2027 TY Baseline)[62]

PSPS Exposure

PSPS exposure is measured by the number of customers at risk of being impacted by PSPS events. PG&E's PSPS model is based on historical data (a looking back approach), utilizing information at the Circuit Protection Zone (CPZ) level to assess the aggregate consequences and frequency of events. The model estimates approximately 1.2 million customers are potentially exposed to PSPS events based on historical data.

[61] CoRE = Consequence of a Risk Event.

[62] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Table 1-2.

EPSS Exposure

EPSS exposure is measured by the mileage of overhead primary circuits capable of enabling EPSS. EPSS-capable circuits are those where EPSS can be activated when the enablement criteria are met. PG&E's EPSS exposure is approximately 43,000 miles.

Observations:

In its 2024 RAMP filing, PG&E changed its designation of exposure miles for the various wildfire risk bow ties and other scenarios to include Secondary and Service (S&S) OH miles. While the S&S OH miles are connected to Primary OH miles and can be included in risk modeling analysis, the S&S miles should be listed in a separate category such as low voltage exposure miles. Separating low voltage exposure miles from high and medium voltage miles will align with regulatory and industry practices and clarify that work on these exposure miles is directly connected to work on specific medium voltage miles. Stated another way, mitigations for these low voltage exposure miles would be optional and implemented only if the corresponding medium voltage miles are mitigated. SPD recommends PG&E break down the exposure mile data based on three voltage categories (High or above 38 kilovolts (kV), Medium or 1 kV to 38 kV, and Low voltage or below 1 kV),[63] with the S&S OH miles categorized as low voltage, in PG&E's TY 2027 GRC.

Tranches

PG&E's wildfire risk is classified by location (i.e., HFRA and non-HFRA) and facility type, with further granularity established for the distribution risk based on the Wildfire Distribution Risk Model (WDRM). Altogether, this framing results in 50 total tranches. Table 1-3 below shows the summary of PG&E's tranche level exposure.

The 2024 RAMP uses a new approach of ten risk deciles instead of the 25 tranches of LoREand CoRE quintiles presented in the TY 2023 GRC. This new method reduces the number of tranches from 25 for HFRA Distribution Primary miles in TY 2023 GRC to 10 tranches in the 2024 RAMP.

PG&E states that it created 10 tranches for HFRA Distribution Primary circuits by ranking CPZs based on mean wildfire risk score for each of the following circuit types: Primary, Secondary, and Services (a total of 30 tranches). HFRA underground (UG) has its own tranche. PG&E's HFTD/HFRA areas contain 25,935 overhead circuit miles (11.6 percent of the total 223,205 wildfire exposure miles),[64] but account for 76 percent of PG&E's wildfire risk (see Figure 1-4). For HFRA Transmission, PG&E separates tranches by 60/70 kV, 115 kV, and 230/500 kV circuits. The second highest risk is attributed to Transmission OH in HFTD/HFRA locations, which constitutes 13 percent of wildfire risk.

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[63] Standard Handbook for Electrical Engineers, 13th Edition by Donald G. Fink / H. Wayne Beaty.

[64] Based on data in PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Table 1-3, SPD calculated total exposure miles to be 996 miles greater than PG&E's reported 222,209 exposure miles.

Table 1-3: Tranche level exposure[65]

Tranche Type	Number of Tranches	Miles in Tranche	Wildfire Risk in Tranche	Risk/Mile
HFRA Distribution Primary	10	25,935	14,853	0.6
HFRA Distribution Secondary	10	2,771	687	0.25
HFRA Distribution Services	10	11,036	765	0.07
HFRA Substation	1	196	19	0.1
HFRA Transmission	3	5,660	2,615	0.46
HFRA Underground	1	3,027	126	0.04
Non-HFRA Distribution Primary	10	54,880	497	0.01
Non-HFRA Distribution Secondary	1	13,385	34	0.003
Non-HFRA Distribution Service	1	67,718	4	0.0001
Non-HFRA Substation	1	801	3	0.004
Non-HFRA Transmission	1	12,326	18	0.001
Non-HFRA Underground	1	25,470	12	0.0005
Aggregated	50	223,205	19,633	.09

Observations:

1. Moving from the more granular 25 HFTD Distribution tranches in previous PG&E TY 2023 GRC[66] to a more coarse 10 tranche approach for HFRA Distribution Primary raises two primary concerns:
    a. Loss of granularity and over-aggregation: Collapsing circuit segments into 10 deciles creates the risk of oversimplification, which could lead to less precise risk management and prioritization of mitigation efforts.
    b. Increased complexity in comparing with historical data: The shift to the 10-decile system does not allow a direct comparison of the 2024 wildfire risk data to historical data collected under the 5x5 risk tranche framework. This could hinder the ability to track

[65] Calculated based on PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1,Table 1-3.

[66] D.23-11-069 at 250-251 (PG&E TY 2023 GRC); A.21-06-021, PG&E Ex-85.

progress, evaluate past risk mitigation measures' effectiveness, and assess wildfire risk changes over time.

2. The values presented in most wildfire workpapers, especially those allocated to system hardening, such as EO-WLDFR-M022_Undergrounding.xlsx and EO-WLDFR-M002_System_Hardening_OH.xlsx, are very dispersed and inconsistent. For example, the risk for each circuit segment is calculated in one workpaper but the values are connected to the other workpapers where tranches are assigned. The workpapers hinder SPD's ability to thoroughly evaluate components of PG&E's 2024 RAMP. Some examples of SPD's concerns include, but are not limited to, the following:
    a. In its 2024 RAMP, PG&E states to have created "ten tranches by ranking CPZs based on mean Wildfire Risk score for each of the following: primary, secondary, and services."[67] Although the Risk Buydown workpaper[68] provides risk scores calculated using WDRM V3 for each circuit segment, PG&E fails to clearly explain its process for assigning these risk-based tranches to specific circuit segments.
    b. In the EO-WLDFR-M022_Undergrounding.xlsx workpaper, (tab "IN2_Primary_UG_Workplan"), PG&E shows the number of miles planned for undergrounding for each circuit segment. However, PG&E provides no explanation of the criteria or methodology it used to select these miles for undergrounding.
    c. The EO-WLDFR-M022_Undergrounding.xlsx, (tab "IN7_WLDFR_Tranches") lists Primary HFRA tranches for each circuit segment, but PG&E fails to explain how these circuit segments were chosen.
    d. In subsequent tabs (all "Calc..." tabs and "WLDFR-MO22" tab), the calculations reference various "INX_" tabs, yet these are provided without any direct linkage to the previously mentioned risk calculations.

SPD requested[69] PG&E clarify the process and provide the underlining calculations for: Q1- How it created tranches from circuit segments, Q2- How it assigned circuit segments to a particular tranche, and Q3- How it prioritized circuit segments for undergrounding. A summary of PG&E's responses to these questions are provided below.

Q1. In response to Q1, PG&E mentioned that tranches are created based on 1) "sort[ing] the distribution circuit segments in order from highest to lowest wildfire mean risk predicted by WDRM V3 and 2) split[ting] the sorted circuit segments into 10 deciles, such that each decile accounts for ~1/10th of the total distribution wildfire risk. Decile 1 consists of the circuit segments with the highest mean risk while decile 10 contains the circuit segments with the

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[67] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, page 1-24 and Table 1-3.

[68] EO-WLDFR-18 WDRM V3 Risk Buydown.xlsx, tab "Baseline Data".

[69] Data Request No. SPD-PGE-2024 RAMP-018.

lowest risk mean."[70] PG&E also clarified that the Primary, Secondary and Service lines in HFRA of the circuit segments in decile x (x = 1 to 10) are assigned to HFRA Distribution Primary - Secondary, and Service - Tranche x, respectively.

Q2. In response to Q2, PG&E stated that "Total WDRM V3 Risk is the cumulative value used to split circuit segments into congruent tranches, after sorting highest to lowest by mean risk rank."[71]

Q3. In response to Q3, PG&E replied, "The circuit segments selected for undergrounding between 2023-2026 are based on PG&E's forecast GRC workplan. Circuit segments selected between 2027-2030 are based on a WDRM V3 risk ranked approach, which first targets the highest remaining mean risk[72] locations not already hardened through 2026. ... PG&E will continue to refine the final targeted circuit segments as future work planning progresses."[73]

SPD finds apparent discrepancies in PG&E's explanation of how it assigned circuit segments to tranches. At the overall tranche level, there is a logical declining level of risk per mile from Tranche 1 to Tranche 10, as presented in Figures 1 and 5 below. However, in the list of circuit segment examples in Table 1-1, the first two listed circuit segments are assigned to Tranche 1 but have relatively low risk at 0.8 and 0.9 risk/mile. These circuit segments have only slightly higher risk/mile than the HFRA Distribution Primary average of 0.6 risk/mile seen in Table 1-2 and are much less than the 2023 Baseline risk/mile of 4.0 for Tranche 1, as shown in Figure 1-5. SPD recommends PG&E demonstrate how it builds tranches based on the risk scores calculated and assigned to each circuit segment. SPD also recommends that PG&E explain why each circuit segment was assigned to a particular tranche and why lower risk circuit segments are assigned to higher risk tranches.

[70] Data Request No. SPD-PGE-2024 RAMP-018

[71] Data Request No. SPD-PGE-2024 RAMP-018

[72] Total WDRM V3 Risk is a product of a circuit segment's mean risk, also known as risk density, and the circuit segment's total length, more specifically the number of risk pixels encompassed by the segment.

[73] Data Request No. SPD-PGE-2024 RAMP-018

		2023 Baseline			2027 TY Baseline		
Row Labels	Miles	Risk	% Risk	Risk/Mile	Risk	% Risk	Risk/Mile
HFRA - Distribution - Primary - Tranche 1	434	1,739	7.9%	4.0	636	3.2%	1.5
HFRA - Distribution - Primary - Tranche 2	596	1,718	7.8%	2.9	627	3.2%	1.1
HFRA - Distribution - Primary - Tranche 3	718	1,743	7.9%	2.4	1,385	7.1%	1.9
HFRA - Distribution - Primary - Tranche 4	869	1,729	7.9%	2.0	1,754	8.9%	2.0
HFRA - Distribution - Primary - Tranche 5	1,088	1,790	8.2%	1.6	1,840	9.4%	1.7
HFRA - Distribution - Primary - Tranche 6	1,340	1,740	7.9%	1.3	1,721	8.8%	1.3
HFRA - Distribution - Primary - Tranche 7	1,765	1,740	7.9%	1.0	1,768	9.0%	1.0
HFRA - Distribution - Primary - Tranche 8	2,535	1,755	8.0%	0.7	1,788	9.1%	0.7
HFRA - Distribution - Primary - Tranche 9	3,930	1,699	7.7%	0.4	1,776	9.0%	0.5
HFRA - Distribution - Primary - Tranche 10	12,660	1,517	6.9%	0.1	1,558	7.9%	0.1

Figure 1-5 HFRA Distribution Primary Tranches Risk/Mile[74]Risk Drivers

Equipment failure is the most frequent risk driver, representing 38 percent of events in the HFTD/HFRA. Vegetation contact is the second most frequent risk driver, representing 34 percent of events.[75]

Observations:

SPD notes that equipment failure and vegetation contact drivers comprise 72 percent of ignition events and 76 percent of HFTD/HFRA areas risk. Of the 192 annual ignitions forecasted for HFTD/HFRA, PG&E Table 1-10 indicates that 1.3 percent of those ignitions (or 2.5 ignitions per year) are expected to result in a catastrophic wildfire. This 1.3 percent of ignitions is estimated to account for 98.4 percent of Wildfire Risk in HFTD/HFRA locations.[76] SPD finds that a small number of ignitions result in catastrophic outcomes, but the current mitigation approach blankets all possible ignitions with costly grid hardening solutions. SPD recommends that PG&E research the nature of risk drivers that lead to catastrophic outcomes, and then develop a mitigation workplan that focuses on mitigating those drivers, where possible.

SPD recommends that PG&E provide a more detailed explanation of how its risk modeling incorporates the highest-frequency drivers (i.e., equipment failure and vegetation contact) when selecting mitigation strategies, particularly focusing on drivers associated with ignitions leading to catastrophic wildfires.

Cross-cutting factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E presents seven cross-cutting factors in the 2024 RAMP. PG&E quantifies the likelihood

[74] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Table 1-6.

[75] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1,Figure 1-6, HFTD/HFRA Risk Bow Tie.

[76] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1.Table 1-10.

impacts for the Physical Attack and Seismic cross-cutting factors into its risk model. PG&E quantifies the consequence impacts for Climate Change and Seismic cross-cutting factors into its model. Other cross-cutting factors influence the baseline risk but have not been quantified (refer to PG&E-4 Table 1-9).

Observations:

The Climate Change Impact graph, PG&E-4 Figure 1-12, illustrates that the risk score for climate change impact increases from $22 billion in 2023 to roughly $26 billion in 2030. After 2030, the climate change impact decreases slightly from $26 billion to $25.5 billion in 2050, then rises sharply after 2050. SPD finds that PG&E did not provide sufficient explanation for these differing expected climate change impacts, such as the model(s) used to estimate them. TURN commented[77] that the PG&E climate change model involving red flag warning ignitions is complex and counterintuitive. The climate risk increases exactly through the rate case period and then decreases afterward. SPD recommends that in its TY 2027 GRC filing, PG&E provide more explanation and justification about the differing expected climate change impacts presented in the 2024 RAMP, including the climate change model(s) used, data, and assumptions.

Consequence

Wildfire

Wildfire Risk consequences are considered along two dimensions: Fire size and RFW days. Fire size is assessed based on the scale or consequence of an ignition, as described below.

> "OEIS[78] Catastrophic : Defined as a CPUC-reportable fire that burns > 5,000 acres, or destroys > 500 structures, or results in a fatality. This aligns with the definition of a catastrophic wildfire provided by OEIS in the guidelines for the 2023–2025 WMP[79].
>
> Non-Catastrophic/Small:
>
> > Destructive: Defined as a CPUC Reportable fire that burns 300 or more acres and destroys no less than 100 structures.
> >
> > Large: Defined as a CPUC-reportable fire that burns 300 or more acres but destroys < 100 structures.
> >
> > Small: Defined as a CPUC-reportable fire that burns fewer than 300 acres.

[77] Informal Comments of The Utility Reform Network (TURN) on PG&E's RAMP Report, p. 22.

[78] Office of Energy Infrastructure Safety.

[79] Wildfire Mitigation Plan.

Non-Reportable Ignitions: Defined as fires that do not meet CPUC reporting criteria and/or are not associated with utility assets."[80]

Figure 1-6 below presents baseline wildfire event consequences (TY Baseline 2027) including Natural Units Per Event, Expected Loss per Year, and Attribute Risk Score.

					Natural Units Per Event				Expected Loss per Year (2023 $M)				Attribute Risk Score			
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Indirect Safety EF/event	Electric Reliability MCMI/event	Financial $M/event	Safety $M/yr	Indirect Safety $M/yr	Electric Reliability $M/yr	Financial $M/yr	Safety $M/yr	Indirect Safety $M/yr	Electric Reliability $M/yr	Financial $M/yr
RFW - Catastrophic	7,965.3	0.23%	87%	2.1	9.32	0.37	63.64	1,245.2	304.43	12.21	432.59	2,670.07	1,722.1	20.3	729.1	14,607.8
Non-RFW - Catastrophic	4,104.9	0.05%	10%	0.5	2.21	0.20	35.47	681.6	16.44	1.52	54.91	332.85	92.6	2.5	91.6	1,817.9
Non-RFW - Non-Catastrophic/Small	0.8	49.10%	2%	450.7	0.00	0.00	0.08	0.1	5.94	2.99	119.99	48.39	6.1	3.1	124.0	237.9
Non-RFW - Non-reportable	0.2	45.32%	0%	416.1	-	0.00	0.06	0.0	-	2.08	77.64	1.45	-	2.1	77.7	1.5
RFW - Non-Catastrophic/Small	2.2	3.91%	0%	35.9	0.00	0.00	0.13	0.4	0.76	0.27	15.13	14.12	0.9	0.3	15.6	62.1
Seismic - Catastrophic	17,153.0	0.00%	0%	0.0	15.21	0.76	128.58	2,530.4	0.21	0.01	0.36	2.24	1.2	0.0	0.7	13.3
RFW - Non-reportable	0.2	1.38%	0%	12.7	-	0.00	0.06	0.0	-	0.06	2.37	0.04	-	0.1	2.4	0.0
Seismic - Non-Catastrophic/Small	15,792.2	0.00%	0%	0.0	-	0.76	128.58	2,530.4	-	0.00	0.01	0.06	-	0.0	0.0	0.3
Aggregated	21.39	100%	100%	918.0	0.02	0.00	0.24	3.3	327.78	19.16	703.00	3,069.23	1,823.0	28.4	1,041.1	16,740.7

Figure 1-6: baseline wildfire event consequences (TY Baseline 2027)[81]

PSPS Consequences

The PSPS Bow Tie framework segments the potential outcomes of a PSPS event based on the types of assets impacted, either transmission (Tx) or distribution (Dx) lines. This segmentation helps target specific mitigations for each outcome, as distribution-focused measures alone cannot mitigate transmission-level PSPS events. The outcomes are:

1. **Customers Scoped by Dx Only**: These customers are impacted only by distribution circuit shutdowns, and account for 70 percent of PSPS events and 67 percent of the associated risk.
2. **Customers Scoped by Tx Only**: These customers lose power due to an upstream transmission line being affected, though not within the direct footprint of the event. This group represents 11 percent of PSPS events and 11 percent of the risk.

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[80] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, page 1-36 lines 15-28.

[81] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Table 1-12.

3. **Customers Scoped by Tx and Dx**: These customers are affected by both transmission and distribution lines being impacted in a PSPS event, representing 19 percent of the events and 22 percent of the risk.

EPSS Consequences

The EPSS outcomes are a subset of the DOVHD (Distribution Overhead) risk outcomes but only include the incremental impact of outages under EPSS conditions. These outcomes account for outages triggered by the enhanced sensitivity of EPSS settings, which aim to reduce wildfire risk but can also affect reliability. The EPSS specific outcomes are:

1. **Sustained Outage**: The sustained outage outcomes only account for the reliability consequence attributable to EPSS since these outages would have occurred regardless of EPSS being enabled. This EPSS related consequence is related to the extended duration due to the additional patrol and re-energization processes required by the EPSS program.
2. **Momentary to Sustained Outage**: These outages would have been brief, momentary interruptions if EPSS were not active. However, these become sustained outages due to the higher sensitivity of EPSS settings. These outages are unique to EPSS and are not included in the general DOVHD risk since it occurs only when EPSS is enabled.

Environmental and Social Justice Consequences

PG&E selected the 2023 Baseline Wildfire Risk as part of an Environmental and Social Justice (ESJ) pilot study plan. PG&E created a methodology to assess the impact on Disadvantaged and Vulnerable Communities (DVC), as defined in CPUC Decision (D.)22-12-027. This methodology was used to calculate the consequences, mitigation benefits, and total costs associated with wildfire mitigations for these communities, ensuring a focus on reducing risk and improving outcomes for vulnerable populations. Refer to this report's Environmental and Social Justice Pilot Study and Implementation chapter for additional information on SPD's observations, findings, and recommendations related to PG&E's ESJ pilot study.

Observations:

Based on PG&E-4 Table 1-11, the number of ignitions resulting in catastrophic outcomes, is 1.3 percent of all ignitions. SPD finds that the small number of predicted catastrophic events is based on a small number of historic data points, which can introduce uncertainty as a predictor of future catastrophic events. SPD also finds that PG&E's analysis is based solely on ignition data, while other sources of information such as unplanned outages and fault data exist.

SPD recommends PG&E describe how it accounts for the uncertainty due to the small sample size of catastrophic events and provide a more detailed explanation of its statistical analyses and risk modeling approach in the PG&E TY 2027 GRC. SPD also recommends that PG&E consider incorporating related data, such as unplanned outages and fault data, into its risk modeling analyses to reduce uncertainty, increase accuracy and sensitivity of its modeling to better predict and manage catastrophic risk events.

SPD finds that PG&E prioritized the mitigation measures based on the highest risk tranches, Tranches 1-5 for undergrounding and 3-5 for covered conductor hardening.[82] However, PG&E has not demonstrated how it addresses the small percentage of catastrophic outcomes with a focused workplan.

SPD finds a potential overlap between the DOVHD and EPSS risk analysis. SPD recommends PG&E explain in its TY 2027 GRC filing how it accounts for the potential overlap between the DOVHD and EPSS risk analyses and proposed mitigations. SPD finds that PG&E has not demonstrated in its RAMP filing how it is focusing PSPS and EPSS strategies to ensure effective application in the highest risk areas. SPD recommends that PG&E refine PSPS and EPSS strategies to ensure they are not widely impacting areas with low likelihood of ignition and low consequence.

SPD finds that PG&E has not presented information regarding how it could leverage other fault energy limiting options, such as REFCL, to reduce EPSS outages. SPD recommends that PG&E comprehensively examine and deploy technologies that can significantly reduce momentary outages.

PG&E's calculation of the financial consequence attribute assumes that the value of each structure destroyed in a wildfire is $1 million, which is the same assumption made in PG&E's 2020 RAMP filing. In Informal Comments, TURN noted that PG&E's assumption significantly overstates the recorded data from 2015-2022, exhibiting a weighted average of $723,000 per structure destroyed.[83] SPD recommends that PG&E use the 2015-2024 weighted average of recorded dollar damage per structure destroyed when estimating the financial consequences attribute in its TY 2027 GRC filing.

PG&E-4 Table 1-15[84] shows the percentage of DVC customers, and the percentage of risk to DVC customers, in both the 10 HFRA Distribution and 10 Non-HFRA Distribution tranches. For both sets of tranches, on average, disadvantaged and vulnerable customers appear to face risk that is proportional to their population: 29 percent of customers are in DVCs, and they face 31 percent of the risk.

However, the risk analysis presented in PG&E's Table 1-15 is missing key information necessary for understanding the implications of its mitigations and the impacts on DVCs. SPD analyzed the PG&E workpaper data for DVC customers in the HFRA and Non-HFRA Distribution Tranches, shown in Table 1-3 below. SPD finds that there are significant differences between the population of DVC customers and the percentage of risk faced by the DVCs in the HFRA Distribution tranches.

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[82] PG&E 2024 RAMP, Workpaper RM-RMCBR-15 RAMP Mitigations and Controls and their CBRs.xlsx.

[83] Informal Comments of The Utility Reform Network (TURN) on PG&E's RAMP Report, October 9, 2024, at 13.

[84] Table 1-15 is supported by PG&E 2025 RAMP Workpaper EO-WLDFR-17_DVC analysis.xlsx Tabs Summary and 2_Tranche and Consequence.

Table 1-4. SPD Analysis of DVC Risk in HFRA vs Non-HFRA Tranches

Distribution Tranche Group	Customers	% DVC Customers	Total Risk	DVC Risk	Non-DVC Risk	% DVC Risk
Grand Total	5,454,992	29%	16,841	5,222	11,619	31%
HFRA Total	505,847	16%	16,306	5,040	11,266	31%
Non-HFRA Total	4,949,145	31%	535	182	353	34%

The breakdown of the tranche groups in Table 1-4 provides an important insight. Within PG&E's HFRA, 16 percent of customers live within a DVC, which was similarly noted in TURN's Informal Comments.[85] However, these HFRA/DVC customers face a disproportionate amount of wildfire risk at 31 percent. PG&E's Table 1-15 only presented a Grand Total result that gives the average for both tranche groups. SPD recommends that PG&E present the HFRA and Non-HFRA subtotals in Table 1-15 for its TY 2027 GRC filing with its ESJ analysis.

PG&E Tables 1-16[86] and 1-17[87] present the risk reduction benefits and reliability impacts from allocation of PSPS and EPSS mitigations to DVCs in only the HRFA tranche group, since that is where those mitigations are applied. However there appears to be an error in the tables since the value used for the Overall Total percentage of DVC customers is taken from Table 1-15's Grand Total representing both HFRA and non-HFRA Distribution Tranches. SPD recommends that PG&E ensure the Grand Totals represent the correct DVC proportion.

SPD finds that PG&E states that the allocation of PSPS and EPSS consequences was done proportionally to DVC customers in each tranche but does not provide details of how that was done, nor how the Interruption Cost Estimator (ICE) reliability value was applied. SPD recommends that PG&E in its TY 2027 GRC filing explain how allocating PSPS and EPSS consequences to DVC customers is supported by data.

Finally, as part of the ESJ Pilot Study, PG&E did not estimate the impacts of wildfire smoke that disproportionately impact DVCs; instead, it stated that wildfire smoke impacts generally require further study. As noted in MGRA's Informal Comments, SPD finds that PG&E should follow the example of

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[85] Informal Comments of The Utility Reform Network (TURN) on PG&E's RAMP Report, October 9, 2024, at 28.

[86] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 1, page 1-45.

[87] *Id.*.

SDG&E to use the measure of "acres burned" as a proxy for estimating wildfire smoke.[88] SPD recommends that PG&E adopt SDG&E's "acres burned" as an interim proxy for estimating the impact of wildfire smoke, including its impact on DVCs, in PG&E's TY 2027 GRC filing unless PG&E incorporates another way to do so.

Controls and Mitigations

PG&E's four wildfire mitigation strategies:

- Data Gathering and Continuous Monitoring: Programs such as weather stations, wildfire cameras, and asset inspections, designed to provide insight into changing environmental hazards around PG&E assets, and continuous monitoring.
- Operational Mitigations: PG&E states these are temporary mitigation programs but also states: "PSPS and EPSS are the most Wildfire Risk reducing and cost-effective programs PG&E deploys."[89]
- System Resilience mitigations: For permanent risk reduction activities, PG&E deploys a long-term System Hardening program (including undergrounding, covered conductor, line removal, and remote grid) and the transmission line removal work that reduces ignition risk by changing how its grid is constructed.
- Customer Awareness and Engagement: PG&E proactively engages with its customers and communities to address issues related to wildfire preparation, ongoing safety work, and other public safety and preparedness issues.

Observations:

PG&E provides cost-benefit ratio (CBR) for four mitigation programs for the GRC period 2027-2030: System Hardening [Overhead], System Hardening [Underground], EPSS, and PSPS. Table 1-5 summarizes NPV risk reductions, NPV costs, and CBRs for these mitigations. SPD observes that EPSS and PSPS programs offer significantly higher CBRs, even when accounting for all program-related consequences, compared to System Hardening, both underground and overhead. The CBRs for EPSS and PSPS are 51.9 and 42.8, respectively, whereas the CBRs for System Hardening, underground and overhead, are substantially lower at 7.9 and 17.8, respectively.

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88 Mussey Grade Road Alliance Informal Comments to the Safety Policy Division Regarding Pacific Gas and Electric Company's RAMP Filing (Revision 1), October 11, 2024, at 29.

89 PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, page 1-4, lines 8-9.

Table 1-5: Mitigation Program CBR Data[90]

Mitigation ID	Mitigation Name	Program Cost ($Mil)	Risk Reduction ($ Mil)	CBR
DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	$449	$7,987	17.8
DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	$6,483	$51,323	7.9
WLDFR-M020	EPSS	$481	$24,975	51.9
WLDFR-M001	PSPS	$119+$34	$6,564	42.8

1. PG&E uses program IDs "DOVHD-M022," "PCEEE-M003," and "WLDFR-M022" to refer to its System Hardening [Underground] efforts proposal in HFTD/HFRA locations. The three program IDs refer to the same program but apply to three different risks in the RAMP report. For the wildfire risk chapter, the "WLDFR" program ID applies. SPD created Tables 1-6 to compare the risk reduction benefits for each corresponding risk chapter of this mitigation program. PG&E breaks down WLDFR-M022 into 30 HFTD Distribution tranches (10 primary, 10 secondary, and 10 service line).[91, 92]
2. SPD notes that PG&E's WLDFR-M022 undergrounding program consists of Primary distribution lines and Secondary and Service (S&S) lines, which SPD separates by costs and CBRs as shown in Table 1-6. The CBR for HFTD/HFRA Primary lines is 10.7, while the CBR for S&S lines is 2.1. Service lines on PG&E distribution system pose four percent of the wildfire risk, while secondary lines comprise about three percent of the wildfire risk. PG&E has noted that HFTD/HFRA primary distribution lines pose 10X greater risk than PG&E's S&S lines combined.[93] Table 1-6

[90] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1,Table 1-25 and workpaper "RM-RMCBR-15 RAMP Mitigations and Controls and their CBRs.xlsx" (tab "all mitigations and controls")

[91] PG&E 2024 RAMP, Workpaper RM-RMCBR-15 RAMP Mitigations and Controls and their CBRs.xlsx, sheet "Tranche-level CBRs".

[92] PG&E 2024 RAMP, Workpaper RMCBR-15 RAMP Mitigations and Controls and their CBRs.xlsx, sheet "All Mitigations and Controls"

[93] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1,Table 1-3, page 1-25.

indicates that though the risk reduction for S&S lines is one-tenth of that for the Primary lines, the cost of undergrounding the S&S lines is disproportionally half the cost of the Primary lines.

Table 1-6: Total NPV cost, NPV Risk Reduction (RR) and CBR for each program ID of the System Hardening [Underground] Program

WLDFR-M022				PCEEE-M003 Total	DOVHD-M022 Total	Grand Total
	Primary	**S&S**	**Total**			
NPV Costs ($Mil)	4,264.740	2,217.849	6,482.590	6,482.590	6,482.590	6,482.590
NPV Risk Reduction ($Mil)	45,592.776	4,702.280	50,295.060	6.170	1,021.94	51,323.170
CBR	10.691	2.120	7.758	0.001	0.158	7.917

The PG&E workpapers[94] provide system hardening mitigation risk reduction, capital expenditure (CapEx), and CBRs for both program and tranche levels. However, PG&E does not clearly explain how these values have been calculated from more granular data like circuit segments, nor provide the underlying data supporting these calculations. SPD recommends that PG&E clarify whether and how it uses CBR values to select the most efficient risk mitigation measures at both the circuit segment and tranche levels in its TY 2027 GRC filing.

Circuit Segment Outliers

SPD observed that some circuit segments show more than 100 percent discrepancies between the overhead circuit miles of lines to be replaced and the circuit miles of planned underground installation. For example, in the Alleghany 1102CB project, 35 miles of underground lines are being installed to replace a 17.78-mile overhead circuit segment.[95] SPD requested PG&E to clarify these differences. In its response, PG&E explained "The undergrounding process generally requires more mileage than the overhead lines being replaced, with a typical conversion factor of 1 mile overhead = 1.25 miles underground. This conversion

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94 PG&E 2024 RAMP, Workpaper files "EO-WLDFR-3h_CBR Input File (System Hardening).xlsx" and "RM-RMCBR-15 RAMP Mitigations and Controls and their CBRs.xlsx".

95 PG&E 2024 RAMP, Workpaper "EO-WLDFR-M022_Undergrounding.xlsx" (tab "IN2_Primary_UG_Workplan") and Workpaper "EO-WLDFR-18 WDRM V3 Risk Buydown.xlsx" (Column D "Primary Overhead HFTD Mileage").

factor is also supported by a CPUC decision (D.21-11-069). However, the risk reduction is tied to removing overhead lines rather than the mileage of underground lines installed, which makes sense from a wildfire risk perspective."[96]

SPD notes that:

a. While the 1.25 conversion factor is applied uniformly across all projects, this approach may oversimplify the unique challenges of individual projects. Variations in terrain, local conditions, and routing complexities can lead to significantly different conversion ratios, and applying a blanket factor may not always accurately capture these differences.

b. The Alleghany 1102CB project exhibits a considerable deviation from the 1.25 conversion factor, with nearly double the underground miles installed compared to the overhead lines being replaced. Such cases warrant closer scrutiny, as outliers like the Alleghany 1102CB project may require more customized risk reduction calculations or specific handling.

c. Limiting the risk exposure to the original overhead mileage ensures a fair calculation of risk reduction but could overlook the added complexities and costs of projects requiring extensive rerouting. Although the risk reduction is linked to the removal of overhead lines, projects involving significant rerouting may warrant special consideration in cost-benefit analyses or project prioritization frameworks. The additional mileage from rerouting could substantially increase project costs without being fully reflected in the risk reduction and CBR metrics, potentially misrepresenting the cost-benefit analyses and justifications for project selections.

EPSS+PSPS Cost Benefit efficiency and further improvement

Currently, PG&E deploys EPSS and PSPS operational mitigations to control wildfire risk, while seeking to reduce the baseline risk and the adverse impacts of EPSS and PSPS with other solutions. SPD evaluated the cost effectiveness of EPSS and PSPS for the 2027-2030 GRC period based on PG&E's RAMP and workpaper information[97] for the NPV costs, NPV risk reductions, and CBRs. PG&E Figure 1-2 illustrates the significant risk reduction contributions of EPSS and PSPS. In the test year the baseline wildfire risk, before mitigations, is projected to be $19.63 billion. PSPS and EPSS reduce this risk to $2.36 billion before considering the consequences of power service interruption. Then, the calculated consequence impacts of PSPS and EPSS are presented to add risk valued at $5.31 billion. The net test year risk is reduced from $19.63 billion to $7.67 billion.[98] PG&E forecasts the PSPS+EPSS risk reduction NPV at $31.54 billion and

[96] PG&E response to Data Request SPD-PGE-2024RAMP-018 Q5.

[97] PG&E 2024 RAMP, Workpaper "EO-WLDFR-2a_Bow Tie (System).xlsm".

[98] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Figure 1-10.

the program and foundational cost NPV at $634 million for 2027-2030,[99] in 2023 dollars, resulting in a combined EPSS/PSPS CBR of 49.7.

PG&E's 2024 RAMP proposed undergrounding a portion of its top 5 highest-risk tranches. SPD compared the proposal's cost-effectiveness with alternatives such as overhead (covered conductors) and PSPS and EPSS to better understand cost-benefit efficiency. SPD requested[100] that PG&E calculate the risk reductions, costs, and CBR for the overhead (covered conductor) alternative for the circuit segments where undergrounding was proposed (portion of primary tranches 1-5). SPD also calculated the cost benefit effectiveness of PSPS and EPSS for these tranches and summarized the results in Table 1-7.

SPD's analyses show that PSPS+EPSS has an exceptionally high CBR of 392.33 in the top 5 tranches,[101] showing that $392 in wildfire risk is mitigated for every dollar spent. Although the NPV risk reduction ($19.24 billion) is lower than undergrounding ($45.59 billion), the significantly lower cost ($49 million compared to $4,625 million) shows PSPS+EPSS is highly efficient in terms of CBR.

SPD finds that although EPSS and PSPS are highly effective at reducing wildfire risk, the negative impacts of service interruption fall disproportionately on customers in high fire threat areas, and the Commission considers PSPS as a mitigation of last resort[102] so that non-interruptive mitigations are preferred. Since these mitigations will continue to be necessary to some extent, SPD recommends that PG&E provide information in the TY 2027 GRC on what steps it is taking to reduce PSPS and EPSS impacts and develop other protective engineering solutions.

As shown in Table 1-7, SPD finds that while undergrounding is the most effective in terms of absolute wildfire risk reduction, it is the least cost-efficient option. SPD finds that covered conductor used for the same miles proposed to be undergrounded has 65 percent of the NPV risk reduction as undergrounding for the same primary tranche miles, at 37 percent of the costs for a CBR of 17.44. In accord with TURN's recommendation,[103] SPD recommends that PG&E provide in its TY 2027 GRC filing CBR calculations for undergrounding and covered conductor and other hardening and operational mitigation alternatives for each tranche and each circuit segment for which it proposes investments to mitigate wildfire risks.

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[99] Calculated based on values in PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Table 1-25.

[100] RAMP-2024_DR_SPD_015.

[101] The PSPS+EPSS NPV risk reductions account for both negative and positive consequences.

[102] D.21-06-034, 6.3.3 page 61.

[103] A.24-05-008 TURN Informal Comments on PG&E 2024 RAMP, page 12.

Table 1-7: Cost benefit efficiency of PSPS+EPSS and CC vs PG&E proposal

Primary Tranches 1-5 2027-2030	NPV Risk Reduction ($M)	NPV Costs ($M)	CBR
PSPS+EPSS	19,239.63	49.04	392.33
UG (proposed in 2024 RAMP)	45,592.78	4,265.00	10.70
Overhead (covered conductor)	29,569.69	1,695.08	17.44

Alternatives Analysis

PG&E presented four alternative plans including:

1. Alternative Plan 1: WLDFR-A001/WPSPS-A001 – System Hardening [UG]
2. Alternative Plan 2: WLDFR-A002 – Grid Monitoring
3. Alternative Plan 3: WLDFR-A003 – Line Slap
4. Alternative Plan 4: WLDFR-A004 – Wildfire Resilience Partnerships – Fuels Treatment

Only Alternative Plan 1, WLDFR-A001/WPSPS-A001, was provided by PG&E as an alternative to the proposed undergrounding program (WLDFR-M022). This plan would mitigate more Primary cable risk through additional miles of undergrounding, but with cost saved from Secondary and Service cable risk being mitigated through overhead hardening rather than with undergrounding. The total cost of this alternative program WLDFR-A001/WPSPS-A001 would be slightly less than the proposed WLDFR-M022, resulting in a somewhat higher CBR. PG&E states this alternative would allow additional funds to be allocated to other electric operations programs, primarily addressing the backlog of identified pole tags. PG&E explained that the following factors led to PG&E's decision not to proceed with this proposal: "Budget re-allocation to pole tag programs would not provide an incremental risk reduction benefit, and the undergrounding of Secondary and Service lines provide additional benefits that are not as easily quantified, such as improvements to PSPS, end of line reliability, and customer satisfaction."[104]

For Alternative Plan 2, WLDFR-A002 Grid Monitoring, PG&E considered the implementation of several line and pole mounted technologies in addition to the proposed WLDFR-M022 to address high priority threats on the distribution system that lack real-time condition monitoring. These threats include time-dependent threats, vibrations, and various hazards. PG&E did not include WLDFR-A002 in the base

[104] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, page 1-98, lines 25-28.

mitigation plan due to the additional analysis required to implement failure probabilities based on sensor data. PG&E is considering piloting sensor programs to help provide further data and understanding.

For Alternative Plan 3, WLDFR-A003 Line Slap, PG&E considered an additional program that addresses the impact of line slap and reconfiguring conductor attachments to address unusual circumstances, such as wind events, that may cause conductors to slap together, possibly resulting in hot metal particles falling to the ground with potential ignitions. PG&E conducted a study using LiDAR data-based methodology and FEA modeling and identified 33,000 HFTD/HFRA spans where conductor-line slapping was most probable. PG&E states that since line slap represents a small number of events, additional review and analysis is required to determine if this program is viable to deploy.

For Alternative Plan 4, WLDFR-A004 Wildfire Resilience Partnerships – Fuels Treatment, PG&E described an incremental program to catalyze targeted community and forest fire resilience aligned with locational risk drivers. In 2023, PG&E started piloting several initiatives with nonprofit organizations and other entities including mechanical thinning, controlled burns, and/or ecologically appropriate reforestation (post-fire).

Observations:

1. Only PG&E's Alternative Plan 1, WLDFR-A001/WPSPS-A001 was presented as a clear alternative to a specific PG&E proposed mitigation (i.e. WLDFR-M022). The other three alternatives were presented more as additional projects that PG&E is piloting or considering in the future. Hence, PG&E did not meet the requirement to provide two Alternatives as required by the RDF decision.[105]
2. PG&E's Alternative Plan 1, WLDFR-A001/WPSPS-A001 maintained nearly the same level of capital investment costs as PG&E's proposed WLDFR-M022. PG&E's Alternative Plan 1 replaced the undergrounding of Secondaries and Services (S&S) with overhead hardening of S&S and increased the primary undergrounding miles. Specifically, PG&E's Alternative Plan 1 proposes 2,300 miles of primary distribution lines in HFTD/HFRA while mitigating the associated S&S with lines through overhead hardening with covered conductor. This results in a comparatively better CBR of 9.7 compared to the original PG&E plan of Undergrounding 1,710 miles of primary lines and 889 of S&S lines, which has a CBR of 7.9. However, in Alternative Plan 1, a portion of the budget is also allocated to address the backlog of identified pole tags which PG&E states provides no incremental risk benefit. Although this alternative shows a higher CBR compared to PG&E's proposed WLDFR-M002 (9.7 vs 7.9) and offers some cost savings, additional elements like the backlogged pole tags add cost without risk benefit.
    a. SPD WLDFR Scenario 3 is an SPD-requested alternative similar to PG&E Alterative Plan 1 with lower cost by maintaining the 1,711 miles of primary line undergrounding as proposed in WLDFR-M002 and installing covered conductors on 890 miles of S&S lines instead of

[105] See D.18-12-014 at 34.

undergrounding them. PG&E provided a partial response to SPD's request[106] in that the contribution of S&S hardening to risk reduction was not included in their analysis, stating "Neither Alternative 1 WLDFR-A001 nor SPD's WLDFR Scenario 3 attribute supplemental risk reduction to hardening secondaries and services. … the risk reduction is only attributed to the units of primary voltage line hardened." Even with that limitation, Scenario 3 produced a CBR of 10.1 compared to the proposed WLDFR-M002 CBR of 7.9, reducing cost by almost $2 billion while achieving 93 percent of the risk reduction[107]. See Table 1-8 for a comparison of Scenario 3 results with other mitigation plan scenarios. SPD finds that Scenario 3's comparison of risk reduction and CBRs would be improved by including risk reduction provided by the S&S hardening.

3. SPD requested PG&E conduct another alternative analysis referenced here as SPD WLDFR Scenario 4 where covered conductor would be installed instead of PG&E's original Undergrounding proposal. In response, PG&E calculated and reported the NPV risk reductions, NPV costs, and CBRs for all tranches if covered conductors were installed instead of Undergrounding (alongside the existing proposed Covered Conductors).[108]

    a. The results of SPD WLDFR Scenario 4 (see Table 1-8 below) demonstrates that overhead hardening (covered conductors) is more cost efficient than undergrounding, even for the tranches with the highest risk. SPD observed that overhead hardening is approximately 63 percent more cost efficient (CBR of 17.4 vs. CBR of 10.7) than underground hardening for the top 5 high-risk tranches. SPD recommends that PG&E in its TY 2027 GRC filing reduce its heavy reliance on undergrounding and propose overhead hardening and other alternative mitigations for a significantly larger portion of its proposed system hardening miles in its 2024 RAMP since undergrounding is the least cost-efficient wildfire mitigation. This recommendation is consistent with the Commission's Decision D.23-11-069 on PG&E's Test Year 2023 General Rate Case where the Commission authorized a hybrid scenario of undergrounding and covered conductor to capture cost savings while still achieving a high level of risk reduction.[109]

4. SPD observes that Rapid Earth Fault Current Limiter (REFCL) technology has been effectively deployed by other electric distribution operators such as the state of Victoria in Australia and Southern California Edison, where the latter has combined REFCL with overhead hardening. SPD is concerned that PG&E did not include REFCL as a proposed or alternative mitigation although PG&E has been evaluating REFCL at one of its substations for multiple years and was authorized

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106 Data Request No. SPD-PGE-2024RAMP-009 Q3.

107 PG&E Response to RAMP_2024_DR_SPD_Oral001-Q003.

108 PG&E Response to DR No. SPD-PGE-2024RAMP-015 Q1.

109 D.23-11-069, p. 272, FOFs 108 and 111, COLs 77, 81, 90 and 91.

funding for REFCL at two new substations per year from 2023 to 2026 in the TY 2023 Decision.[110] However, the Decision recognized that PG&E's plans for REFCL installation could change depending on pilot results. In response to a data request PG&E stated[111] "PG&E continues evaluation of REFCL technology in its EPIC 3.15 demonstration project at Calistoga substation."

SPD requested that PG&E provide alternative risk modeling analysis utilizing REFCL for all three-wire circuit segments where PG&E proposed to install Undergrounding in the PG&E 2024 RAMP.[112] SPD also requested that PG&E provide alternative risk modeling analysis utilizing REFCL + Covered Conductor for all three-wire circuit segments where PG&E proposed installing Undergrounding in the PG&E 2024 RAMP.[113] PG&E did not provide the alternative mitigation analyses requested by SPD for REFCL, stating that PG&E does not currently have sufficient data to assess the viability of REFCL as an alternative mitigation and therefore does not believe it is appropriate or necessary to prepare an alternative mitigation analysis based on REFCL.[114]

SPD understands that without sufficient data, it is not appropriate for PG&E to prepare an alternative mitigation analysis based on REFCL but finds there have been positive indications for the potential success of REFCL. PG&E has reported that the "fault energy measured for sustained low impedance faults with REFCL active was fewer than 10 percent of the fault energy with EPSS settings and solid grounding [and the] distribution system was able to ride through momentary staged faults [with REFCL]."[115] PG&E has stated: "in reviewing mitigation alternatives as part of our upcoming SB 884 filing, we estimate a 65 percent mitigation effectiveness for REFCL."[116]

SPD recommends that PG&E provide an update on the progress of the REFCL pilot at Calistoga and if the pilot has not yet been completed, the pilot project plan detailing the remaining steps to acquire the necessary data on REFCL to perform mitigation analysis.

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110 D.23-11-069 pp. 292-293

111 PG&E Response to RAMP-2024_DR_SPD_017-Q002.

112 SPD-PGE-2024RAMP-017-Q004.

113 SPD-PGE-2024RAMP-017-Q005.

114 PG&E responses to data request SPD-PGE-2024RAMP-017-Q004 and -Q005.

115 PG&E 2023-2025 Wildfire Mitigation Plan Revision 6, p. 580.

116 PG&E 2025 Wildfire Mitigation Plan Update R1, p. 70.

Table 1-8: NPV cost, NPV Risk Reduction (RR) and CBR for System Hardening scenarios

Mitigation ID	Mitigation Name or Type	Scenario	Primary vs S&S	Miles	NPV Costs ($Mil)	NPV Risk Reduction ($Mil)	CBR
DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	PG&E 2024 RAMP	Primary	360	449	7,987	17.8
DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	PG&E 2024 RAMP	Primary	1,711	4,265	45,592.78	7.9
			S&S	890	2,218	4,702.28	
WLDFR-A001/WPSPS-A001		PG&E RAMP Alternative 1[117]	Primary	2300	6,261	60,726	9.7
	Backlog Open Tag Reduction -Distribution	PG&E 2024 RAMP Alt. 1-Tag Backlog	NA	NA	389	41	0.11
	UG Primary, OH S&S	SPD Scenario 3	Primary	1711	4,628	46,619	10.1
			S&S	890			
	All OH	SPD Scenario 4	Primary	1711	1,695	29,569	17.4
			S&S	890	882	3,074	3.5

[117] PG&E's Alternative1 proposes to underground 2,300 miles HFTD/HFRA primary distribution lines with secondary and service lines being mitigated through OH hardening. This plan allocates additional budget to backlog of identified pole tags

CBR Calculations

Observations:

1. To better understand wildfire risk in PG&E's territory and to better analyze and recommend a more cost-efficient mitigation plan, SPD requested[118] that PG&E calculate costs, risk reduction, and CBR at the circuit segment level for all circuits proposed for undergrounding in its 2024 RAMP. Even though the RDF does not require presentation of data below the tranche level, SPD can request more detailed information to assist in its evaluation. PG&E did not provide the requested data at the circuit segment level, explaining that "we did not calculate NPV costs at the circuit segment level, as the capital cost per mile was a simple average across the 2027-2030 period, and not a reflection of the year(s) of installation …. because NPV Risk Reduction and NPV Costs are not calculated in this response (as described above), the associated CBR cannot be calculated using that data."[119]
   a. Considering that PG&E's risk tranches comprise numerous circuit segments, SPD finds that if PG&E did not calculate NPV costs and CBR at the circuit segment level, its NPV costs and CBR calculations for each wildfire tranche may not be accurate.
   b. PG&E's decision to use a simple average for capital cost per mile across the 2027-2030 period rather than reflecting the specific year(s) of installation raises concerns about the accuracy of its cost projections. The timing of capital expenditures is crucial when calculating NPV, as costs incurred earlier in the period should be discounted differently than those incurred later. Without this granularity, the NPV could be distorted, leading to inaccurate representations of the true costs for each circuit segment.
   c. PG&E asserts that it cannot calculate the CBR at the circuit segment level due to the lack of NPV risk reduction and cost data. Without CBRs calculated for individual circuit segments, SPD is concerned that PG&E cannot fully evaluate the cost efficiency of each specific project. This lack could result in misallocating resources, potentially leading to underestimating or overestimating the risk-reduction benefits across different segments. This lack of granularity limits PG&E's ability to effectively prioritize wildfire mitigation efforts where they are needed most.
   d. The lack of detailed CBR data hinders SPD's ability to compare different mitigation strategies and prioritize segments based on cost efficiency. The lack of circuit-level data makes assessing PG&E's mitigation proposals difficult. SPD relies on the tranche data to recommend improvements or alternative strategies. SPD's finding that the tranche-level CBRs are not based on complete circuit-level data means that a tranche-based analysis is only as good as the

118 Data Request PG&E 2024 RAMP-007.

119 PG&E response to RAMP-2024_DR_SPD_007.

assumptions PG&E made to develop the tranche CBRs. SPD relies on the tranche data to recommend improvements or alternative strategies.

Additional System Hardening Due to Operational Constraints

1. PG&E states that it "will never be able to solely work down a risk buy-down exclusively, as it is generally not operationally feasible. As an example, there are circuit segments upstream and downstream of high-risk circuit segments that may sit on a lower risk tranche."[120] SPD interprets this as PG&E needing to deploy projects with low CBRs in low-risk areas because of operational constraints (e.g., upstream, downstream circuits) or other reasons. SPD asked PG&E to clarify: "How does PG&E account for the costs of additional undergrounding for downstream and upstream miles associated with high-risk OH primary miles? How does PG&E incorporate and report these additional costs? How does PG&E differentiate the costs associated with the downstream and upstream underground miles from costs associated with the proposed work on the tranches in the 2024 RAMP?"[121] PG&E responded that "PG&E includes the cost per mile in the program cost, regardless of the risk profile. The scoping decision is based on established standards and procedures that directly support high-risk UG projects. PG&E does not differentiate the referenced costs. In the RAMP, PG&E provided an estimation of high-risk CPZs, however, considered the operational efficiencies in the scoping process."[122]
    a. SPD finds that PG&E has not identified the cost impact of mitigating upstream and downstream miles of high-risk circuit segments. SPD also finds that PG&E has claimed it is not operationally feasible to solely work down a risk buy-down, as upstream and downstream mileages in low-risk CPZs exist. SPD recommends PG&E provide more granular information regarding these upstream and downstream circuit miles, including but not limited to miles, costs, and justification, in addition to the associated high-risk circuit segments.
    b. SPD finds that PG&E did not incorporate costs and risk reduction estimates related to these upstream and downstream circuit miles when calculating costs, risk reduction and CBRs for the high-risk associated tranches. Associated tranches and CPZs refer to the high-risk tranche and high-risk circuit segments, which are the primary reasons for hardening these downstream and upstream circuits. SPD also recommends PG&E incorporate the costs and risk reductions of these additional circuit miles into the associated tranche and CPZ CBRs selected for system hardening. High-risk tranches and circuit segments should be determined including the risk reductions and costs of hardening all upstream and downstream circuits that are needed due to operational constraints.

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120 PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, page. 1-29, lines 11-15.

121 SPD-PGE-2024RAMP-009_Q002.

122 PG&E Response to SPD-PGE-2024RAMP-009_Q002.

Other observations

Risk Model and Data Consistency

To address the previous observations regarding: 1 – the lack of clarity of the impact caused by changing wildfire risk models between RAMP filings, 2 – the lack of transparency in of the process of circuit segment assignment to tranches and mitigation selection for circuit segments, and 3 – PG&E's insufficient granular tranches, SPD created a data template consisting of three tables[123] and shared the template with PG&E to help structure and present the data in the RAMP on wildfire mitigations. While the level of granularity requested in the template is not currently required as part of the RDF (Risk-based Decision-making Framework in proceeding R.20-07-013), SPD intends to consider templates such as these, and the associated data and granularity, in a Phase 4 Technical Working Group of the RDF proceeding for incorporation into future RDF requirements.

The template was designed to organize utility data into consistent and coherent datasets, clarifying the often-ambiguous processes of analysis and decision-making that PG&E undertakes when analyzing different mitigations and proposing mitigation plans. The template consists of three tables, all consistently related through circuit segments, which is the most granular physical level used by PG&E to model risk. The template attempts to address three key issues: 1 – Changes in calculated risk across risk model versions (Table 1), 2 – Effectiveness of mitigations at the circuit segment level (Table 2), and 3 – Justifications for chosen mitigations (Table 3). Snapshots of the SPD template are shown in Figure 1-7.

a. The first issue the template addresses is SPD's finding that significant changes can occur in the calculated risk of each circuit segment from one risk model to the next. PG&E regularly updates its risk models. At times, new risk model versions' outputs (calculated risks) are substantially different from the previous version(s). In some cases, PG&E has changed the length and names of each circuit segment from one risk model to another. Table 1 in the SPD template collects data regarding changes in calculated risk, length, and name of each circuit segment, which PG&E plans to include in its proposed mitigation programs. This enables the analysis and comparison of data created across different risk models and supports comparison of such data across various proceedings where such data may be presented. PG&E populated Table 1 and SPD used that data to study how the changes in calculated risk varied between PG&E risk model versions (refer to Risk Model Changes section). PG&E's 2024 RAMP uses outputs from its V3 risk model while the PG&E TY 2027 GRC will use V4 risk model.
b. Table 2 allows for a more effective analysis and comparison of proposed mitigations and alternatives by collecting basic information on proposed mitigations and alternatives at the circuit segment level. These data include, but not limited to, consequence (financial, safety, and reliability) and likelihood attributes of risk to facilitate calculation of risk pre- and post-mitigation implementation, as well as the CBR associated with each mitigation. Table 2 is a one-to-many

[123] "Data Request PG&E 2024 RAMP-007.xlsx".

dataset, where each circuit segment is repeated in several rows, with a feasible mitigation, depending on how many mitigations are feasible for that specific circuit segment. This table would be the foundation for analyzing PG&E's proposed mitigation compared to other alternatives. For the current RAMP, SPD recommends PG&E investigate the feasibility of and provide related information for various mitigations, undergrounding (UG), covered conductor (CC), CC+REFCL, CC+EPSS, and EPSS-solely mitigations, and any other proposed mitigations, for each circuit segment.

c. PG&E partially responded to SPD's data request related to provide circuit segment level risk model data (i.e., Table 2), including the tranche assignment, and pre- and post-mitigation risk scores. However, the values for NPV risk reduction and NPV cost were not provided for each circuit. PG&E stated it cannot calculate CBRs at the circuit segment level, and the cost per mile is calculated as the average across 2027-2030.[124] SPD finds that net present value of risk reduction requires information about when the project would begin producing benefits and that PG&E must make project benefit assumptions to calculate NPV risk reduction at the tranche level. Hence, SPD also finds that, since each circuit segment has been assigned to a tranche, PG&E could use the same tranche specific project benefit assumption for NPV risk reduction and NPV cost and apply those to each of the circuit segments assigned to those tranches to determine an estimated circuit segment CBR. While perhaps not fully accurate, those calculations would provide useful insight for analysis of mitigation proposals. SPD recommends that PG&E calculate an estimated CBR, stating the assumptions made, at the circuit segment level for each mitigation in its TY 2027 GRC filing.

d. Table 3 requires PG&E to justify each proposed mitigation. The main purpose of Table 3 is to determine if the proposed mitigation for a specific circuit segment is based on the merits of its cost efficiency or qualitative factors such as operational considerations. In response to an SPD data request, PG&E stated, "We cannot provide the information as requested in Table 3 because PG&E has not determined the mitigation measure at the circuit segment-level for the 2027-2030 RAMP period. Mitigations are selected when circuit segments are scoped for execution, which will take place closer to the execution date." SPD finds that PG&E could not provide justifications for mitigations at the circuit segment level due to the timing of project scoping. SPD recommends that PG&E provide justifications for mitigations at the circuit segment level in its TY 2027 GRC filing for segments that have been scoped and explain what assumptions it has made for un-scoped segments that led to its proposed mitigation work plan.

[124] PG&E response to SPD data request RAMP-2024_DR_SPD_007-Q001.

Fields (table 1)	Description
Circuit Segment	
Total Miles V2	
HFRA Miles V2	
Total Miles V3	
HFRA Miles V3	
Total Miles V4	
HFRA Miles V4	
Risk V2	Wildfire Distribution Risk Model (Version 2)
Risk V3	Wildfire Distribution Risk Model (Version 3)
Risk V4	Wildfire Distribution Risk Model (Version 4)

Fields (table 2)	Description
Circuit Segment	
Tranche	Tranche assigned in 2024 RAMP
Substation Name	
Substation MVA	
Wire Configurations (3 wires vs 4 wires)	3 or 4 or other
Mitigation	The proposed mitigation and any alternative mitigations practically possible: UG, CC, CC+REFCL, CC+EPSS and EPSS
HFRA Miles	
Non-HFRA Miles	
Cost per Mile	
Likelihood Pre-mit	The likelihood of an ignition before any mitigation applied
Safety Pre_Mit (Natural)	Pre-Mitigated Safety (Natural Units)
Reliability Pre_Mit (Natural)	Pre-Mitigated Reliability (Natural Units)
Financial Pre_Mit (Natural)	Pre-Mitigated Financial (Natural Units)
Safety Post_Mit (Natural)	Post-Mitigated Safety (Natural Units)
Reliability Post_Mit (Natural)	Post-Mitigated Reliability (Natural Units)
Financial Post_Mit (Natural)	Post-Mitigated Financial (Natural Units)
CMI	Customer minutes interrupted used to monetize Reliability Pre_Mit (Natural)
VSL	Value of statistical life used to monetize Safety Post_Mit (Natural)
Pre-Risk	Pre-Mitigated Risk
Pos-Risk	Post-Mitigated Risk
NPV Risk Reduction	
NPV Costs	
CBR	

Fields (table 3)	Description
Circuit Segment	
Mitigation chosen	One mitigation among: UG, CC, CC+REFCL, CC+EPSS and EPSS
Justification1	Primary reason to choose the mitigation measure 1-Higher CBR 2-operational concerns (upstream and downstream or associated Secondary and service lines) 3-Egress constraints 4-fire suppression 4-other
Justification2	Secondary reason to choose the mitigation measure: 1-Higher CBR 2-operational concerns (upstream and downstream or associated Secondary and service lines) 3-Egress constraints 4-fire suppression 4-other
Start Year	The year that Circuit Segment is scoped
Used and Useful year	The year the Circuit Segment is used and useful after mitigation
Associated high risk Circuit Segment	If number 2 (operational concerns) is chosen in any justification field, "Associated high risk Circuit Segment" refers to the high-risk circuit segment connected to and/or associated with the circuit segment being mitigated.

Figure 1-7: SPD data template (Tables 1, 2, and 3)

SPD finds that PG&E partially responded to SPD's data requests related to circuit segment level risk model data. However, PG&E failed to explain how changes in calculated risk across risk model versions would affect its mitigation strategy. For example, in its TY 2023 GRC, PG&E used WDRM V2, while in the 2024 RAMP WDRM V3 is used.[125]

[125] Refer to Risk Model Changes section below

Risk Model Changes

The RAMP and GRC processes are closely linked. RAMP filings provide the critical risk assessment and mitigation planning that informs the detailed financial and operational plans presented in the GRC.PG&E used V3 of its risk model in the 2024 RAMP and is expected to use V4 for the PG&E TY 2027 GRC.[126] SPD finds that changes for each circuit segment should be traceable between risk model versions to ensure oversight of all proposed mitigations.

To clarify this issue further, SPD issued a data request[127] to PG&E to provide more information regarding differences in the calculated risk and miles in PG&E's risk model versions 3 and 4 for all circuit segments, where PG&E proposed implementing any mitigations in its 2024 RAMP. SPD analyzed the changes in calculated risk, at the circuit segment level, between PG&E's model versions and presents the results in Figure 1-8 below. The upper part of the graph (V4-V3) shows the changes from version 3 to version 4 and lower part of the graph (V3-V2) shows the changes from version 2 to version 3. The dark blue bars, "Null" in all four graphs, identify whether a circuit segment doesn't exist in the older or newer version of the model. SPD finds that although the percentage of changes in calculated risk and circuit segment names from V4 to V3 are less pronounced when compared to the previous version update (i.e., from V3 to V2), 92 percent of the calculated risk in circuit segments changed by more than 20 percent from V3 to V4.[128]

To clarify its decision-making process and consequent proposed mitigations for each circuit segment, SPD recommends that PG&E identify and explain why the risks for any circuit segment changes more than 20 percent from PG&E's WDRM risk model V3 to V4, and how it impacts PG&E's mitigation proposal.

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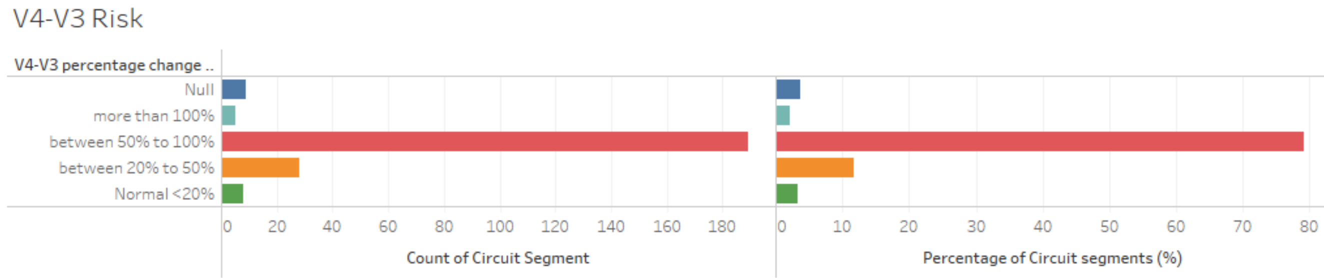
[126]See PG&E Data Request response to CalAdvocates, WMP-Discovery2023-2025_DR_CalAdvocates_040-Q005, April 12, 2024, at 1-2. PG&E explained that "WDRM V4 will begin to inform scoping of undergrounding projects as early as the second half of 2024 for undergrounding projects planned for completion in 2027 and beyond." and "WDRM V4 will begin to inform scoping of overhead hardening (covered conductor) projects as early as the second half of 2024 for projects expected to be completed in 2027 and beyond."

[127] Data Request PG&E 2024 RAMP-007.xlsx

[128] Calculated risk change percentage is (Risk V4 - Risk V3) *100/(Risk V3)



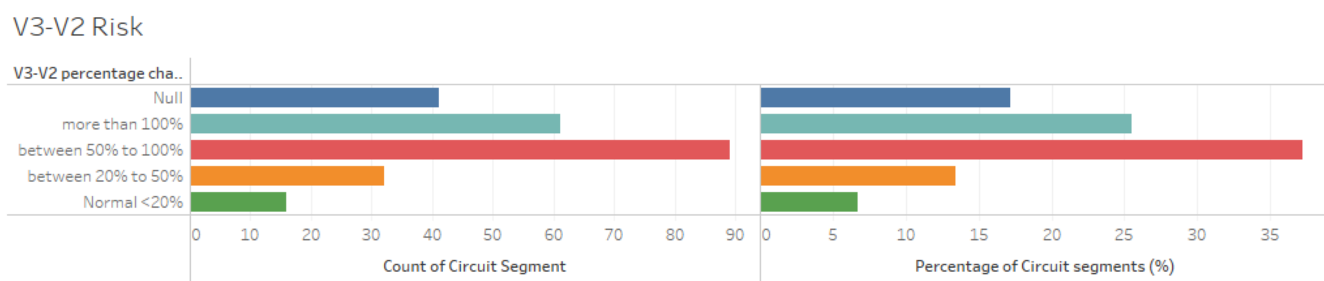


Figure 1-8: Differences in the calculated risk in PG&E's risk models for circuit segments which PG&E proposed any mitigation in 2024 RAMP.[129, 130]

SPD further analyzed PG&E circuit segment length (mile) changes between WDRM risk models, as presented in Figure 1-9. This illustrates how PG&E changed the length of some circuit segments from one risk model to the next. SPD finds that, although changes in the length of circuit segments for most circuits are less than 20 percent (e.g., 87 percent of circuit segment length changes from V3 to V4 are within the 20 percent range), almost 10 percent of circuit segment lengths changed by more than 20 percent. SPD recommends that PG&E explain why a circuit segment in the proposed mitigation plan in the 2024 RAMP (using V3) has more than a 20 percent change in length (mileage) when reported in the TY 2027 GRC (using V4).

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[129] SPD created these graphs based on Table 1 of the data report: Data Request for PG&E 2024 RAMP-007.xlsx

[130] Null in the graphs refers to circuit segment name changes, indicating that the circuit segment names do not exist in at least one WDRM risk model.

SPD recommends that PG&E provide details regarding all changes in circuit segment risk, length, and name, as outlined in the template provided by SPD, to enable a better understanding and review of PG&E's planned mitigations.

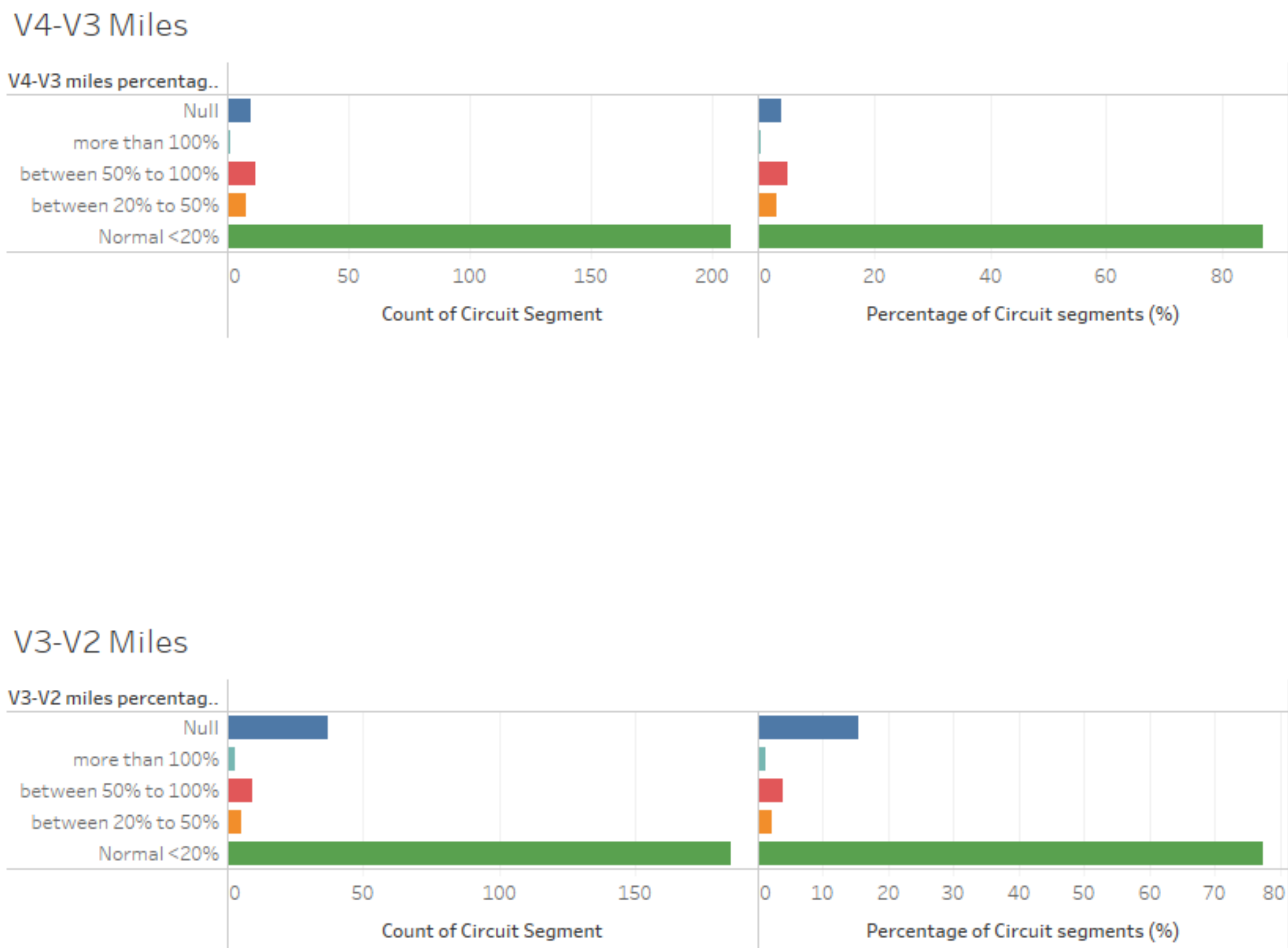

Figure 1-6: PG&E's circuit segment length change in different risk models[131].

[131] SPD created these graphs based on Table 1 of the data request PG&E 2024 RAMP-007.xlsx

Summary of Findings

1. SPD finds no discernable correlation between the risk/mile values and PG&E's assigned tranches.
2. In its 2024 RAMP filing, PG&E changed its designation of exposure miles for the various wildfire risk bow ties and other scenarios to include Secondary and Service (S&S) OH miles.
3. PG&E reduces the number of tranches from 25 (5x5) for HFRA Distribution Primary miles in its TY 2023 GRC to 10 tranches in 2024 RAMP. Moving from the more granular 25 tranches to a coarser 10 tranche approach for HFRA Distribution Primary raises two primary concerns:
    a. Loss of granularity and over-aggregation could lead to less precise risk management and prioritization of mitigation efforts.
    b. Increased complexity in comparing risk data in the 2024 RAMP with historical data could hinder the ability to track progress, evaluate the effectiveness of past risk mitigation measures, and assess changes in wildfire risk over time.
4. Most wildfire workpapers, especially those allocated to system hardening, lack consistency and cohesion. Specific examples include:
    a. PG&E doesn't clearly outline the process for assigning risk-based tranches to specific circuit segments. There is no correlation between risk/mile and PG&E's assigned tranches.
    b. No explanation of the criteria or methodology PG&E used to select miles planned for undergrounding is provided.
    c. PG&E doesn't explain how the circuit segments were chosen for undergrounding.
5. SPD finds apparent discrepancies in PG&E's responses, explaining how it assigns circuit segments to tranches.
6. Equipment failure and vegetation contact are the two most frequent risk drivers, comprising 72 percent of all risk events and 76 percent of the total risks.
7. SPD finds that the risk score for climate change impact increases from $22,000 M in 2023 to $26,000 M in 2030, while it decreases slightly until 2050 when it starts rising sharply again. SPD finds that PG&E did not provide sufficient explanation for these differing expected climate change impacts, such as the model(s) used to estimate them.
8. TURN commented that the PG&E climate change model involving red flag warning ignitions is complex and counterintuitive. The climate risk increases exactly through the rate case period and then decreases afterwards.
9. Based on Exhibit PG&E-4, Table 1-11, the number of ignitions resulting in catastrophic outcomes, is only 1.3 percent of all ignitions. SPD finds that the small number of predicted catastrophic events is based on a small number of historical data points, which can introduce uncertainty as a predictor of future catastrophic events.
10. SPD finds that PG&E's analysis is based solely on ignition data, while there are other sources of information such as unplanned outages and fault data.
11. SPD finds that PG&E prioritized the mitigation measures based on risk tranches, Tranches 1 to 5 for undergrounding and Tranches 3 to 5 for covered conductor hardening. However, PG&E has not demonstrated how it addresses the small percentage of catastrophic outcomes with a focused workplan.

12. SPD finds a potential overlap between the DOVHD and EPSS risk analysis.
13. SPD finds that PG&E has not demonstrated in its RAMP filing how it is focusing PSPS and EPSS strategies to ensure they are applied effectively in the highest risk areas.
14. SPD finds that PG&E has not presented information regarding how it could leverage technology to reduce EPSS outages that would have traditionally only been momentary.
15. PG&E's calculation of the financial consequence attribute assumes that the value of each structure destroyed in a wildfire would be worth $1 million. TURN commented that PG&E's assumption significantly overstates the actual recorded data from 2015-2022 and exhibits a weighted average of $723,000 per structure destroyed.
16. SPD finds significant differences between the population of DVC customers and the percentage of risk faced by the DVCs in the HFRA Distribution tranches. Within PG&E's HFRA, 16 percent live within a DVC, which was noted in TURN's Informal Comments, and these HFRA/DVC customers face a disproportionate amount of wildfire risk: 31 percent. PG&E Tables 1-16 and 1-17 present the risk reduction benefits, and reliability impacts, from allocation of PSPS and EPSS mitigations to DVCs in the HFRA tranche group, since that is where those mitigations are applied. However, there appears to be an error in the tables since the value used for the Overall Total percentage of DVC customers is taken from Table 1-15's Grand Total of both HFRA and non-HFRA Distribution tranches.
17. PG&E finds that the allocation of PSPS and EPSS consequences was done proportionally to DVC customers in each tranche but does not provide details of how that was done, nor how the ICE reliability value was applied.
18. As part of the ESJ Pilot Study, PG&E did not estimate the impacts of wildfire smoke that disproportionately impact DVCs; instead, it stated that wildfire smoke impacts generally require further study.
19. SPD finds, as noted in MGRA's Informal Comments, that PG&E should follow the example of SDG&E to use the measure of "acres burned" as a proxy for estimating wildfire smoke.
20. SPD finds the CBRs for EPSS and PSPS are 51.9 and 42.8, respectively, whereas the CBRs for System Hardening, underground and overhead, are substantially lower at 7.9 and 17.8, respectively.
21. PG&E uses program IDs "DOVHD-M022", "PCEEE-M003", and "WLDFR-M022" to refer to its System Hardening [Underground] proposal in HFTD/HFRA locations. The three program IDs refer to the same program but apply to three different risks in the RAMP report. For the wildfire risk chapter, the "WLDFR" program ID applies.
22. SPD created Table 1-5 to compare the risk reduction benefits for each corresponding risk chapter from this same mitigation program. PG&E breaks down WLDFR-M022 into 30 HFTD Distribution tranches (10 primary, 10 secondary, and 10 service lines).
23. SPD notes that PG&E's WLDFR-M022 undergrounding program consists of Primary distribution lines and Secondary and Service lines (S&S), which SPD separated by costs and CBRs as shown in Table 1-5. The CBR for HFTD/HFRA Primary lines is 10.7, while the CBR for S&S lines is 2.1. Service lines on PG&E distribution system pose 4 percent of the wildfire risk, while secondary lines comprise about 3 percent of the wildfire risk. PG&E has noted that HFTD/HFRA primary distribution lines pose 10X greater risk than PG&E's secondary and service (S&S) drops combined.

Table 1-6 indicates that though the risk reduction for S&S lines is one-tenth of that for the Primary lines, the cost of undergrounding the S&S lines is disproportionally half the cost of the Primary lines.

24. The PG&E workpapers provide system hardening mitigation risk reduction, capital expenditures (CapEx), and CBRs for both program and tranche levels. However, PG&E does not clearly explain how these values have been calculated from more granular data like circuit segments, nor the underlying data supporting these calculations.
25. SPD observed that some circuit segments show more than 100 percent discrepancies between the overhead circuit miles of lines to be replaced and the circuit miles of planned underground installation. For example, in the Alleghany 1102CB project, 35 miles of underground lines are being installed to replace a 17.78-mile overhead circuit segment. SPD notes that:
    a. While the 1.25 conversion factor is applied uniformly across all projects, this approach may oversimplify the unique challenges of individual projects. Variations in terrain, local conditions, and routing complexities can lead to significantly different conversion ratios, and applying a blanket factor may not always accurately capture these differences.
    b. The Alleghany 1102CB project exhibits a considerable deviation from the 1.25 conversion factor, with nearly double the underground miles installed compared to the overhead lines being replaced. Such cases warrant closer scrutiny, as outliers like this project may require more customized risk reduction calculations or specific handling.
    c. Limiting the risk exposure to the original overhead mileage ensures a fair calculation of risk reduction but could overlook the added complexities and costs of projects requiring extensive rerouting. Although the risk reduction is linked to the removal of overhead lines, projects involving significant rerouting may warrant special consideration in cost-benefit analyses or project prioritization frameworks. The additional mileage from rerouting could substantially increase project costs without being fully reflected in the risk reduction and CBR metrics, potentially misrepresenting the cost-benefit analyses and justifications for project selections.
26. SPD finds that although EPSS and PSPS are highly effective at reducing wildfire risk, the negative impacts of service interruption fall disproportionately on customers in high fire threat areas, and the Commission considers PSPS as a mitigation of last resort,[132] so that non-interruptive mitigations are preferred.
27. SPD finds that PG&E has observed positive indications for the use of REFCL compared to EPSS, including reduced fault energy and the ability to ride through momentary faults. PG&E estimates a 65 percent mitigation effectiveness for REFCL in anticipation of their SB 884 filing.
28. SPD finds that while undergrounding is the most effective in terms of absolute wildfire risk reduction, it is the least cost-efficient option. Covered conductor has 65 percent of the NPV risk reduction as undergrounding for the same primary tranche miles, at 37 percent of the costs for a CBR of 17.44.

[132] CPUC D.21-06-034, 6.3.3 Discussion, page 61

29. Only PG&E's Alternative Plan 1, WLDFR-A001/WPSPS-A001 was presented as a clear alternative to a specific PG&E proposed mitigation (i.e. WLDFR-M022). The other three alternatives were presented more as additional projects that PG&E is piloting or considering in the future. Hence, PG&E did not meet the requirement to provide two Alternatives as required by the RDF decision.
30. PG&E's Alternative Plan 1, WLDFR-A001/WPSPS-A001 maintained nearly the same level of capital investment costs as PG&E's proposed WLDFR-M022. PG&E's Alternative Plan 1 replaced the undergrounding of Secondaries & Services (S&S) with overhead hardening of S&S and increased the primary undergrounding miles. Specifically, PG&E's Alternative1 proposed undergrounding 2,300 miles of primary distribution lines in HFTD/HFRA while mitigating the associated S&S lines through overhead hardening with covered conductor. This results in a better CBR of 9.7 when compared to PG&E's original plan of Undergrounding 1,710 miles of primary lines and 889 of S&S lines, which has a CBR of 7.9.
31. In PG&E's Alternative Plan 1, a portion of the budget is also allocated to address the backlog of identified pole tags which PG&E states provides no incremental risk benefit.
32. Although PG&E's Alternative Plan 1 shows a higher CBR compared to PG&E's proposed WLDFR-M002 (9.7 vs 7.9) and offers some cost savings, additional elements like the backlogged pole tags add cost without risk benefit.
33. SPD WLDFR Scenario 3 is an SPD-requested alternative similar to PG&E Alternative Plan 1 with lower costs by maintaining the same 1,711 miles of primary line undergrounding as PG&E's proposed plan (WLDFR-M022) and installing covered conductor on 890 miles of S&S lines rather than undergrounding them.
34. PG&E stated that neither Alternative 1 WLDFR-A001 nor SPD's WLDFR Scenario 3 attribute supplemental risk reduction to hardening secondaries and services.
35. SPD's Scenario 3 produced a CBR of 10.1 compared to the proposed WLDFR-M002 CBR of 7.9, reducing costs by almost $2 billion while achieving 93 percent of the WLDFR-M002 risk reduction.
36. SPD finds that Scenario 3's comparison of risk reduction and CBRs would be improved by including risk reduction provided by the S&S overhead hardening.
37. SPD WLDFR Scenario 4 is another SPD-requested scenario for alternative analyses where covered conductor is installed instead of PG&E's WLDFR-M022 undergrounding proposal. SPD WLDFR Scenario 4 results demonstrate that overhead hardening (covered conductor) is more cost efficient than undergrounding, even for the tranches with the highest risk.
38. SPD observed that overhead hardening (covered conductors) is approximately 63 percent more cost efficient (CBR of 17.4 vs. CBR of 10.7) than undergrounding for the top 5 tranches with the highest risk.
39. PG&E did not provide SPD requested costs, risk reduction, and CBR data at the circuit segment level for all circuits proposed for undergrounding. PG&E stated, "we did not calculate NPV costs at the circuit segment level, as the capital cost per mile was a simple average across the 2027-2030 period, and not a reflection of the year(s) of installation … because NPV risk reduction and NPV Costs are not calculated …, the associated CBR cannot be calculated using that data."

a. Considering that PG&E's risk tranches comprise numerous circuit segments, SPD finds that if PG&E did not calculate NPV costs and CBR at the circuit segment level, its NPV costs and CBR calculations for each wildfire tranche may not be accurate.
b. PG&E's decision to use a simple average for capital cost per mile across the 2027-2030 period rather than reflecting the specific year(s) of installation raises concerns about the accuracy of its cost projections. The timing of capital expenditures is crucial when calculating NPV, as costs incurred earlier in the period should be discounted differently than those incurred later. Without this granularity, the NPV could be distorted, leading to inaccurate representations of the true costs of each circuit segment.
c. PG&E asserts that it cannot calculate the CBR at the circuit segment level due to the lack of NPV risk reduction and cost data. Without CBRs calculated for individual circuit segments, PG&E cannot fully evaluate the cost efficiency of each specific project. This could result in the misallocation of resources, potentially leading to underestimating or overestimating the risk-reduction benefits across different segments. This lack of granularity undermines PG&E's ability to prioritize wildfire mitigation efforts where they are needed most.
d. The lack of detailed CBR data hinders SPD's ability to compare different mitigation strategies and prioritize segments based on cost efficiency. The lack of circuit-level data makes it difficult to assess and validate PG&E's mitigation proposals properly. SPD relies on detailed data to evaluate each project's effectiveness and cost-efficiency; without it, the ability to recommend improvements or alternative strategies is limited.

40. PG&E has not identified the cost impacts or risk reduction of mitigating upstream and downstream miles when calculating high-risk circuit segments' costs, risk reduction, and CBRs. SPD finds that PG&E has claimed it is not operationally feasible to solely work down a risk buy-down as upstream and downstream mileages are located in low-risk CPZs. SPD finds that PG&E did not incorporate costs and risk reduction estimates related to these upstream and downstream circuit miles when calculating costs, risk reduction and CBRs for the high-risk associated tranches.
41. SPD finds that net present value of risk reduction requires information about when the project would begin producing benefits and that PG&E must make project benefit assumptions to calculate NPV risk reduction at the tranche level. Hence, SPD also finds that, since each circuit segment has been assigned to a tranche, PG&E could use the same tranche specific project benefit assumption for NPV risk reduction and NPV cost and apply those to each of the circuit segments assigned to those tranches to determine an estimated circuit segment CBR.
42. SPD finds that PG&E did not provide justifications for the chosen mitigations at the circuit segment level due to the timing of project scoping.
43. SPD finds that PG&E partially responded to SPD's data requests related to circuit segment level risk model data. However, PG&E failed to explain how changes in calculated risk across risk model versions would affect its mitigation strategy.
44. SPD finds that changes for each circuit segment should be traceable between risk model versions to ensure oversight of all proposed mitigations.

a. Although the percentage of changes in calculated risk and circuit segment names from V4 to V3 are less pronounced than in previous version updates (from V3 to V2), 92 percent of the calculated risk in circuit segments changed more than 20 percent from V3 to V4.
b. Although changes in the length of circuit segments for most circuits are less than 20 percent (e.g., 87 percent of circuit segment length changes from V3 to V4 are within the 20 percent range), almost 10 percent of circuit segment lengths have changed more than 20 percent.

Recommended solutions to address findings and deficiencies

For the TY 2027 GRC, SPD recommends that:

1. PG&E break down the exposure mile data based on three voltage categories (High, Medium, and Low voltage) with the S&S OH miles categorized as Low voltage.
2. PG&E demonstrate how it builds tranches based on the risk scores calculated and assigned to each circuit segment.
3. PG&E provide the details of why each circuit segment was assigned to a particular tranche and explain why lower risk circuit segments are assigned to higher risk tranches.
4. PG&E provide a more detailed explanation of how its risk modeling incorporates the highest frequency drivers (i.e., equipment failure and vegetation contact) when selecting mitigation strategies, particularly focusing on drivers associated with ignitions leading to catastrophic wildfires.
5. PG&E provide more explanation and justification about the differing expected climate change impacts presented in the 2024 RAMP, including the climate change model(s), data and assumptions.
6. PG&E describe how it accounts for the uncertainty due to the small sample size of catastrophic events, and a more detailed explanation of its statistical analyses and risk modeling approach.
7. PG&E consider incorporating related data such as unplanned outages and fault data into its risk modeling analyses to reduce uncertainty, increase accuracy and sensitivity of its modeling to better predict and manage catastrophic risk events.
8. PG&E explain how it accounts for the potential overlap between the DOVHD and EPSS risk analyses and proposed mitigations.
9. PG&E refine PSPS and EPSS strategies to ensure they are not widely impacting areas with low likelihood of ignition and low consequence.
10. PG&E comprehensively examine and deploy technologies (including, but not limited to, REFCL) that can significantly reduce momentary outages.
11. PG&E use the 2015-2023 weighted average of recorded dollar damage per structure destroyed when estimating the financial consequences attribute.
12. PG&E present the HFRA and Non-HFRA subtotals PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Table 1-15 for its TY 2027 GRC filing with its ESJ analysis.
13. PG&E ensure the Grand Totals represent the correct DVC proportion.
14. PG&E provide an explanation how allocating PSPS and EPSS consequences to DVC customers is supported by the data.

15. PG&E adopt SDG&E's "acres burned" as an interim proxy for estimating the impact of wildfire smoke, including its impact on DVCs, unless PG&E incorporates another way to do so.
16. PG&E clarify whether and how it uses CBR values to select the most efficient risk mitigation measures at both the circuit segment and tranche.
17. PG&E provide information on what steps it is taking to reduce PSPS and EPSS impacts and develop other protective engineering solutions.
18. PG&E provide CBR calculations for undergrounding and covered conductor and other hardening and operational mitigation alternatives for each tranche and each circuit segment for which it proposes investments to mitigate wildfire risks.
19. PG&E reduce its heavy reliance on undergrounding and propose overhead hardening and other alternative mitigations for a significantly larger portion of its proposed system hardening miles in its 2024 RAMP since undergrounding is the least cost-efficient wildfire mitigation.
20. PG&E provide an update on the progress of the REFCL pilot at Calistoga and if the pilot is not yet completed, the pilot project plan detailing the remaining steps to acquire the necessary data on REFCL to perform mitigation analysis.
21. PG&E provide more granular information regarding the upstream and downstream circuit miles (refer to Summary of Findings, #48), including but not limited to, miles, costs, and justification, in addition to the associated high-risk circuit segments.
22. PG&E investigate the feasibility and provide related information for various mitigations, undergrounding (UG), covered conductor (CC), CC+REFCL, CC+EPSS, and EPSS-solely mitigations, and any other proposed mitigations, for each circuit segment.
23. PG&E calculate an estimated CBR, stating the assumptions made, at the circuit segment level for each mitigation.
24. PG&E provide justifications for mitigations at the circuit segment level in its TY 2027 GRC filing for segments that have been scoped and also explain what assumptions they have made for un-scoped segments that led to their proposed mitigation work plan.
25. PG&E identify and explain why the risks for any circuit segment changes more than 20 percent from PG&E's WDRM risk model V3 to V4, and how it impacts PG&E's mitigation proposal.
26. PG&E explain why a circuit segment in the proposed mitigation plan in its 2024 RAMP (using V3) has more than a 20 percent change in length (mileage) when reported in its TY 2027 GRC (using V4).
27. PG&E provide details regarding all changes in circuit segment risk, length, and name, as outlined in the template provided by SPD, to enable a better understanding and review of PG&E's planned mitigations.

2. Loss of Containment (LOC) on Gas Transmission Pipeline

Risk Description

The LOCTM risk refers to a failure of a gas transmission pipeline resulting in a Loss of Containment (LOC), with or without ignition, that could lead to significant impact on public safety, employee safety, contractor safety, property damage, environmental damage, financial loss, and the inability to deliver natural gas to customers. The failure of a gas transmission pipeline includes both pipeline leaks and pipeline ruptures.[133] See Table 2-1 below, which includes the Risk Definition, Scope, and Data Sources.

Table 2-1: Risk Defintion and Scope

LOSS OF CONTAINMENT ON GAS TRANSMISSION PIPELINE	
Definition	Failure of a gas transmission pipeline resulting in a LOC, with or without ignition, that could lead to significant impact on public safety, employee safety, contractor safety, property damage, financial loss, or the inability to deliver natural gas to customers. Failure of a gas transmission pipeline includes both pipeline leak and pipeline rupture.
In Scope	Failure of a transmission pipeline that leads to a significant LOC (leak or rupture). Significant is defined as a LOC that results in an injury requiring in-patient hospitalization, a fatality, or total costs valued at $50,000 or more, measured in 1984 dollars. Pipeline and Hazardous Materials Safety Administration (PHMSA) 49 Code of Federal Regulations (CFR) Part 191.3 lists the leak reporting criteria, which is used in the RAMP LOCTM model.
Out of Scope	A LOC driven by large overpressure events, LOC on distribution assets.
Data Quantification Sources	PHMSA reports from 1984-2023; Output from Transmission Integrity Management Program (TIMP) operational risk model – Working Assessment Plan (WAP) data based on TIMP 2022 risk run result; Gas Quarterly Incident (GQI) data: 2010-2022

133 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 1, page 1-3, lines 7-12.

Observations:

PG&E identified the failure of gas transmission pipeline resulting in a Loss of Containment (LOC) in its risk description. PG&E manages gas pipeline transmission risk through its Transmission Integrity Management Program (TIMP).

Bow Tie

PG&E presents critical information on the analysis of risk drivers and outcomes of the LOCTM risk in its Bow Tie model.

Observations:

The LOCTM Bow Tie includes the required drivers and risks from industry-leading standards for integrity management.[134] PG&E conducted the Bow Tie analysis for LOCTM consistent with the CPUC's Risk-Based Decision-Making Framework (RDF). The model identifies Drivers on the left side to calculate the likelihood of a risk event (LoRE), and Outcomes on the right side to calculate the consequences of a risk event (CoRE). See Figure 2-1. The model shows multiple outcomes associated with different downstream pipeline characteristics, an improvement from the 2020 RAMP LOCTM Bow Tie.

[134] ASME B31.8S, Managing System Integrity of Gas Pipelines.

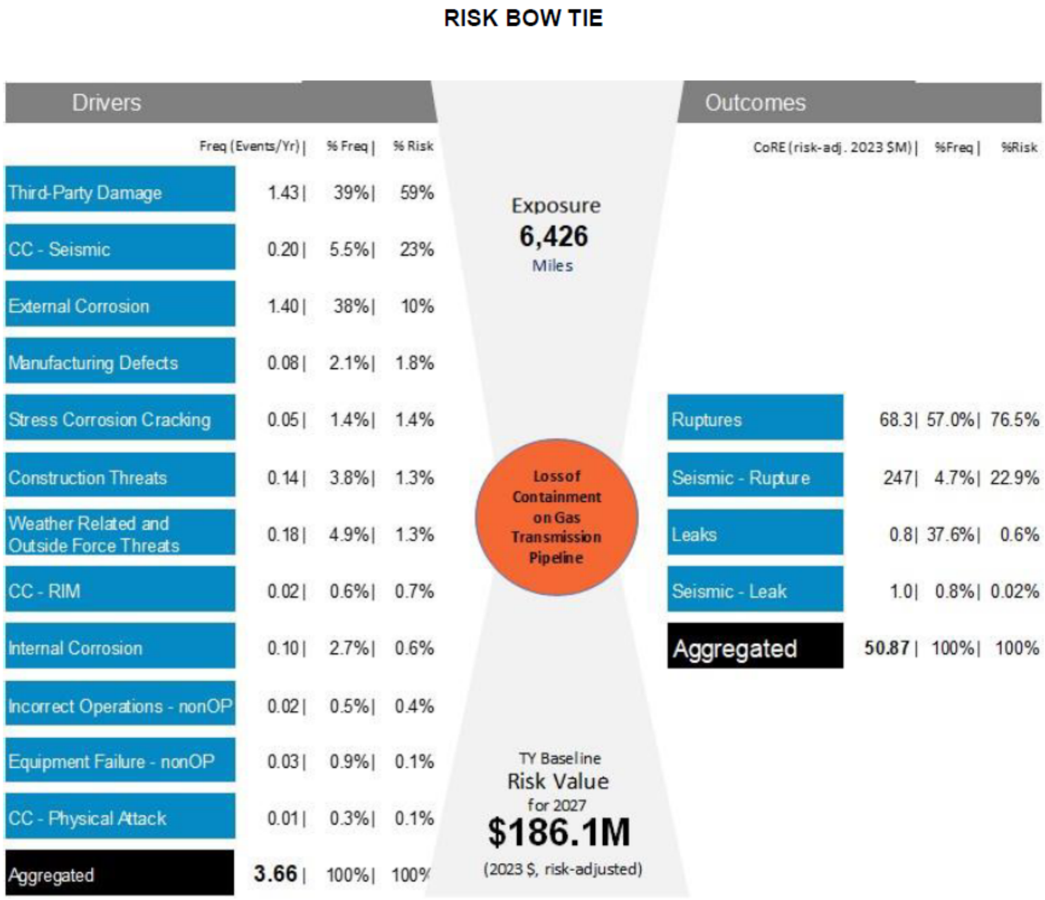

Figure 2-1: Risk Bow Tie

Exposure

PG&E's total exposure for the LOCTM risk is 6,426 miles of gas transmission pipeline.

Observations:

Gas transmission pipelines are the backbone of supply to PG&E's Gas Operations and operate at high pressure with large pipe diameters over long distances. Using miles of pipeline as the unit of measure for exposure is consistent with examples provided in the definition of "exposure" in the RDF.

D.23-12-003, Ordering Paragraph 4 approved PG&E's Transmission Definition Change that reclassified 600 miles of transmission pipelines as distribution pipelines. The Commission will evaluate the impact of this change in the 2027 GRC filing.

Tranches

PG&E identified 24 tranches for the LOCTM risk. Each tranche represents a group of transmission assets determined to have similar risk profiles associated with Likelihood of Failure (LOF) and Consequence of Failure (COF) of LOCTM events. Assets were assigned tranches based on six LOF categories and four COF categories that resulted in the 24 tranches. Tranches are influenced by asset health attributes. PG&E will continue to explore asset health for future tranche categories as risk modeling continues to mature.[135]

Observations:

PG&E utilizes six LOF categories:

- L1: Shallow/exposed pipe.
- L2: Geohazard pipe.
- L3: Potential SCC/SSWC pipe.
- L4: Potential IC pipe.
- L5: Potential manufacturing defect pipe.
- L6: All other pipe.

PG&E clarified that LOF categories are not synonymous with threats as each LOF category contains pipelines with multiple threats.[136] The pipeline segments in the LOF categories have at least one threat in common and similar threat-specific integrity assessments[137]. PG&E stated that pipeline segments are prioritized (i.e., placed into tranches) as follows: L2, L3, L5, L1, L4, L6. In addition, regardless of the LOF pipeline segment prioritization, the total risks for all drivers associated with the pipeline segment are included.

PG&E utilizes four COF categories:

- C1: High Consequence Area (HCA).
- C2: Moderate Consequence Area (MCA).
- C3: Impacted Occupancy Count (IOC) > 0 and rupture mode on Non-HCA/MCA.
- C4: IOC = 0 or leak mode on Non-HCA/MCA.

SPD observes PG&E does not distinguish COF categories based on whether the rupture or leak results in an ignition. SPD finds a significant variance in consequences exist for risk events when an ignition occurs compared to those with no ignition especially in High Consequence Areas and, to a less extent, Moderate

135 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 1, page 1-8, lines 23-28 and page 1-11, lines 8-11.

136 SPD Data Request, RAMP-2024_DR_SPD_004-Q007.

137 SPD Data Request. RAMP-2024_DR_SPD_004-Q007.

Consequence Areas. SPD recommends PG&E add distinctions for ignition and no ignition events at least for HCAs to further contextualize its analysis of LOCTM risk.

PG&E's response to SPD data request RAMP-2024_DR_SPD_004_Q002 clarified the C3 category includes pipeline segments that could fail by rupture or leak, whereas the C4 category includes pipeline segment where the IOC = 0 or pipeline segments that only fail by leak.
Regarding LOCTM tranches, PG&E stated "Using GIS and other tools, tranches are calculated from the TIMP Risk Model. The main purpose of using tranches is to improve understanding of how likelihoods and consequences of failure can inform risk-based decision making. Likelihood factors can help inform the probability of a LOC from a specific threat, manifested as pipeline leaks or ruptures per mile per year for pipe segments within that threat's tranche. Consequence factors can help inform the distribution of consequences when pipe experiences a LOC. The 24 tranches allow for more targeted assessment by tranche to identify and reflect awareness of investments in risk reduction activities. Both LOF and COF categories are drawn from threat-specific likelihood and consequence area data used for TIMP's program scoping and prioritization."[138]

In response to the SPD data request (RAMP-2024_DR_SPD_004_Q006) PG&E advised that Figure 2-2 below illustrates how pipelines with similar risk profiles were assigned to each tranche.

[138] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 1, page 1-10, lines 3-7 and page 1-11, lines 1-7.

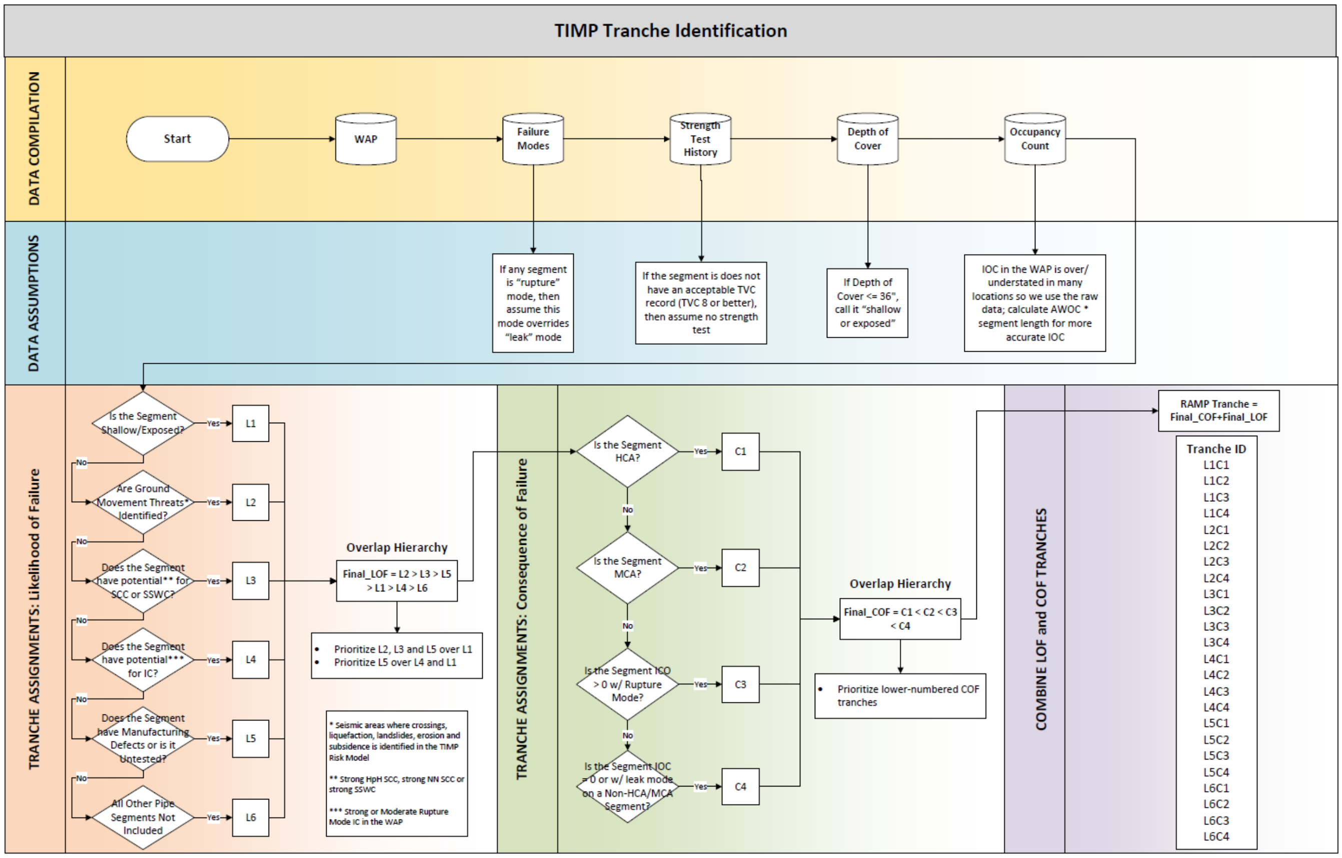

Figure 2-2: GO-LOCTM-25_Tranche Work Flow

LoRE values at each tranche use TIMP segment-level LOF scores for the pipeline segments that map to that tranche. PG&E uses Pipeline and Hazardous Materials Safety Administration (PHMSA) data, seismic model results, and subject matter expert estimates to develop factors that facilitate the calculation of tranche-subdriver-outcome level LoRE when it can't be computed directly from TIMP model.[139] Safety CoRE values at each tranche use TIMP IOC by the pipeline segments that map to that tranche. Reliability CoRE values at each tranche use TIMP customer count values by pipeline segments that map to that tranche. Financial CoRE does not use the data from TIMP Risk model outputs.[140] Additional LoRE and CoRE values are derived from TIMP risk model inputs and are selectively utilized to support decision making for select programs, depending on active threats and assessment methods available to address threats. Based on segment-to-tranche mapping, segment-level LOF and COF (i.e., IOC) values are used to support the tranche-level LoRE and CoRE calculation.[141]

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139 SPD Data Request, RAMP-2024_DR_SPD_022-Q001.

140 SPD Data Request, RAMP-2024_DR_SPD_014-Q001.

141 SPD Data Request, RAMP-2024_DR_SPD_014-Q002.

For LOCTM risk modeling purposes, PG&E assumes all pipe segments in a given tranche have a uniform risk score in a given year.[142] For LOCTM risk mitigation modeling purposes, PG&E assumes a uniform risk reduction per mile in a given year for a given mitigation in a given tranche.[143]

Risk Drivers

PG&E has identified nine primary risk drivers for its LOCTM risk. Risk drivers D8 and D9 affect both the LOCTM risk and the Gas Overpressure, Measurement and Control Failure (LRGOP) risk (Exhibit PG&E-3, Chapter 3).[144]

Observations:
The nine risk drivers are listed below. In addition to these, PG&E uses three cross-cutting factors: Seismic, RIM, and Physical Attack. PG&E's failure likelihood algorithm addresses the LOF of each risk driver.

D1 – Third-Party Damage:
D2 – External Corrosion
D3 – WROFs
D4 – Construction Threats
D5 – Internal Corrosion
D6 – Manufacturing Defects
D7 – Stress Corrosion Cracking
D8 – Incorrect Operations
D9 – Equipment Failure

SPD finds the nine primary risk drivers utilized for the LOCTM risk are appropriate, as derived from the American Society of Mechanical Engineers (ASME) Standard B31.8S.

Risk Drivers Frequencies

To model this risk, PG&E utilized internal gas frequency and consequence data (derived from PG&E's current transmission pipeline conditions and location) and PHMSA data from 1984 through June 2023. The PHMSA data includes Gas Transmission incident reports from 1984 to June 2023.[145] The PHMSA data was used to supplement PG&E data where driver frequencies from the TIMP risk model were unavailable.[146]

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[142] SPD Data Request, RAMP-2024_DR_SPD_022-Q002.

[143] SPD Data Request, RAMP-2024_DR_SPD_022-Q003.

[144] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 1, page 1-13, lines 2-7.

[145] PHMSA reporting requirements for incidents differed over these different periods of time (1984-2002, 2002-2010, and June 2010-2023).

[146] 2024 RAMP Report Exhibit PG&E-3 Chapter 1, page 1-14, lines 24-29.

Observations: None.

Outcome Frequencies

Loss of Containment outcomes are ruptures, leaks, seismic – rupture, and seismic – leak. The highest frequency outcome is ruptures, at 57 percent and the second highest frequency outcome is leaks, at 37.6 percent of the total outcome occurrences. The remaining two outcomes, Seismic – Rupture and Seismic – Leak have 4.7 percent and 0.8 percent of the total outcome occurrences, respectively.

Observations: None.

Cross-cutting factors (CCF)

PG&E analyzed the five cross-cutting factors listed below:

1. Climate Change (not quantified in the model – impacts likelihood)
   a. Currently not modeled.
   b. Climate Adaptation and Vulnerability Assessment (CAVA) analysis indicates limited impact of Climate Change to gas transmission assets.
   c. Additional research is needed to determine the impact to a LOCTM event.
2. Emergency Preparedness and Response (not quantified in the model – impacts consequence)
   a. While this CCF impacts the RAMP risk, it was extracted from the data and considered or mapped separately
   b. "Embedded" Modeling Method
3. Physical Attack (impacts likelihood)
   a. Modeling Method: 1) Driver (extracted from existing data)
   b. Risk Frequency: 0.3 percent (0.01 Events/years)
   c. Percent of Risk: 0.09 percent
4. RIM (impacts both likelihood and consequence)
   a. Modeling Method: 1) Driver (extracted from existing data), 2) Consequence Multiplier
   b. Risk Frequency: 0.6 percent (0.02 Events/years)
5. Seismic (impacts both likelihood and consequence)
   a. Modeling Method: 1) Driver (added frequency), 2) Outcome
   b. Risk Frequency: 5.5 percent (0.2 Events/years)
   c. Percent of Risk: 23 percent

Observations:

As shown in the Bow Tie, total risk presented by CCFs are relatively low to moderate. When combined, the three CCFs PG&E quantifies in the model are approximately 6.1 percent of the frequency and 23.8 percent of the total LOCTM risk value. SPD's review concludes PG&E has adequately analyzed CCFs for the LOCTM risk.

Consequences

PG&E measures the consequence of the LOCTM risk based on the following three criteria:

1. Did the LOC result in a leak?
2. Did the LOC result in a rupture?
3. Was the leak or rupture caused by a seismic event?

PG&E identified four outcomes: Ruptures, Ruptures seismic, Leaks, and Leaks seismic.

Observations:

PG&E confirmed that material and operating characteristics help determine whether a pipeline segment is identified as a "leak failure" or "rupture failure" mode. PG&E uses its TIMP model to determine whether a pipeline's failure mode is rupture or leak for cracking or corrosion-based threats.**Error! Bookmark not defined.** Seismic ruptures and leaks are modeled with higher consequences per LOC event.[147]

SPD observed the consequence classifications PG&E uses do not distinguish between ruptures or leaks that resulted in an ignition and those that did not. See the Consequence section for further discussion.

PG&E implicitly includes environmental damage as a financial consequence. PG&E models financial consequences based on PHMSA incident data, including the costs of environmental cleanup and damage.[148]

SPD concurs with PG&E's analysis that most of the consequence risk (99.4 percent) is contained within two outcomes: Ruptures and Seismic-Ruptures, aligns with industry wide analysis and modeling.

Controls and Mitigations

Controls:

PG&E listed 11 controls in the 2020 RAMP and 37 controls in its 2023 GRC. PG&E listed 32 controls for the 2024 RAMP/2027 GRC cycle (see workpaper "GO-LOCTM-3_CBR Input File.xlsm").

Observations:

Of the 32 Controls, PG&E lists C30, C37, and C38 as foundational activities and does not calculate a CBR for these three since they are foundational activities. CBRs are calculated for the remaining 29 Controls.

[147] SPD Data Request, RAMP-2024_DR_SPD_004-Q003.

[148] SPD Data Request, RAMP-2024_DR_SPD_004-Q004.

SPD notes that C008, Pipeline Safety and Reliability, only has risk reduction values for 2027 with no entries for 2028 through 2030. However, C008 shows costs for years 2027 through 2030. The CBR for this control is only calculated for 2027. PG&E did not forecast specific projects for C008 and did not estimate risk reduction for 2028 through –2030. Reasons were:

1. PG&E was working on strengthening the program's risk-tiering
2. Additional long-term projects may be based on continued field investigations and pipeline inspections
3. Many of the programs here are not bound to the same assessment cycles as those in ILI or DA.[149]

Below is a detailed description of C008:

1. Replacement for pipelines greater than 50 feet with safety or reliability issues not captured by other Maintenance Activity Type (MAT)'s.
2. Repair for pipelines with a non-capital asset installed and/or less than 50 feet of pipe was cut-out and replaced.

C008 includes the following programs[150]:

1. MAT 75O: Pipe Rplcmnt – Oth PL Sfty Inv
2. MAT JTB: No Program Name in Workpapers**Error! Bookmark not defined.**

Mitigations:

PG&E proposed the following four mitigations:

1. **LOCTM-M001 – Vintage Pipe Replacement** addresses replacement of pipeline segments containing vintage fabrication and construction threats subject to high risk of land movement and in proximity to population.[151]
2. **LOCTM-M002 – Shallow and Exposed Pipe (Including Water and Levee Crossings)** identifies, prioritizes, and mitigates locations where pipeline has insufficient cover, is vulnerable to exposure from third parties, or has become exposed due to natural forces.[152]
3. **LOCTM-M003 – Non-TIMP Strength Testing** addresses required strength testing, including 1) to initially establish or reconfirm a Maximum Allowable Operating Pressure (MAOP), 2) a Class Location change, and 3) when used as an integrity assessment tool to meet regulatory requirements and to fulfill PG&E's obligations to the National Transportation Safety Board Safety

[149] SPD Data Request, RAMP-2024_DR_SPD_004-Q004.

[150] SPD Data Request, RAMP-2024_DR_SPD_004-Q004

[151] 2024 RAMP Report Exhibit PG&E-3 Chapter 1, page 1-38, lines 16-19.

[152] 2024 RAMP Report Exhibit PG&E-3 Chapter 1, page 1-38, lines 20-30.

Recommendation P-10-4, Public Utilities Code Section 958, and 49 Code of Federal Regulations (CFR), Part 192.624.[153]

4. **LOCTM-M004 – Valve Automation** addresses the installation of automated isolation valves on pipelines in heavily-populated areas to enhance emergency response and to potentially reduce danger to emergency personnel and the public in the event of a pipeline rupture.[154]

Observations:

The four proposed mitigations have CBRs ranging from <0.03 to 0.78. LOCTM-M001, Vintage Pipe Replacement (CBR = 0.78) and LOCTM-M004: Valve Automation (CBR = 0.46) have the highest CBRs of the four proposed mitigations. LOCTM-M002: Shallow and Exposed Pipe (Including Water and Levee Crossings) has a CBR of 0.03, and LOCTM-M003: Non-TIMP Strength Testing has a CBR of 0.04. PG&E's planned units of work (see Figure 2-3 below), CBRs, and factors affecting mitigation selections (see Figure 2-4 below) for each proposed mitigation are shown below:

SPD observes that PG&E proposes only 63 percent of its proposed mitigation miles in the top six riskiest tranches, which account for 87 percent of the total risk score.[155]

2027-2030 PLANNED MITIGATIONS

Line No.	Mitigation ID	Mitigation Name	Unit of Measurement (a)	Planned Units of Work 2027	2028	2029	2030	Total
1	LOCTM-M001	Vintage Pipe Replacement	Miles	2.9	1.3	1.3	1.3	6.9
2	LOCTM-M002	Shallow and Exposed Pipe (Including Water and Levee Crossings) Mitigation	Projects	2	2	2	2	8
3	LOCTM-M003	Non-TIMP Strength Testing	Miles	31.2	32.6	34.0	35.5	133
4	LOCTM-M004	Valve Automation	Valves	15	15	16	17	63

(a) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from "rate case" units – the units referred to in PG&E's GRC or other proceedings.

Note: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.

Figure 2-3: 2027-2030 Planned Mitigations

153 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 1, page 1-38, lines 31-34 and page 1-39, lines 1-3.

154 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 1, page 1-39, lines 4-8.

155 SPD Data Request, RAMP-2024_DR_SPD_022-Q004.

MITIGATION COST ESIMATES, RISK REDUCTION, CBR AND FACTORS AFFECTING SELECTION 2027-2030 CAPITAL

			Thousands of Nominal Dollars				Millions of Dollars (NPV)(a)				
Line No.	Control No.	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR(b) [C]/([A]+[B])	Factors Affecting Selection
1	LOCTM-M001	Vintage Pipe Replacement	$2,000	$2,056	$2,115	$2,174	$7.9	$0.0	$6.1	0.8	Risk Tolerance, Operational and Execution Considerations
2	LOCTM-M002	Shallow and Exposed Pipe (Including Water and Levee Crossings) Mitigation	6,807	6,997	7,199	7,400	26.8	0.3	0.7	<0.1	Compliance, Risk Tolerance, Operational and Execution Considerations
3	LOCTM-M003	Non-TIMP Strength Testing	70,381	72,343	74,429	76,514	311.2	2.5	12.3	<0.1	Compliance, Risk, Tolerance, Operational and Execution Considerations
4	LOCTM-M004	Valve Automation	17,541	18,030	18,550	19,069	69.1	-	31.5	0.5	Compliance, Risk Tolerance, Operational and Execution Considerations
5		Total	$96,730	$99,425	$102,292	$105,157					

(a) NPV uses a base year of 2023.
(b) CBR calculations include allocated Foundational Activity Program costs.
Note: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

Figure 2-4: Mitigations Costs Estimates, Risk Reduction, CBR and Factors Affecting Selection 2027-2030 Capital

PG&E cited risk tolerance to justify the four mitigations in Figure 2-5. The Commission has not issued a decision regarding risk tolerance. This topic will be addressed in Phase 4 of the active RDF rulemaking proceeding, R.20-07-013. PG&E did not provide sufficient justification as it only included a qualitative citation to risk tolerance (e.g., it did not define a risk tolerance value or framework). More detailed information regarding risk tolerance should be provided in all cases where PG&E cited risk tolerance as justification for proposed mitigation.

PG&E also has not included sufficient documentation[156] to use operational and execution considerations as justification for proposed mitigations[157] with CBRs lower than 1.0.

[156] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 1, pp. 1-54, lines 13-24.

[157] LOCTM-M002: Shallow and Exposed Pipe (Including Water and Levee Crossings) and LOCTM-M003: Non-TIMP Strength Testing.

LOCTM-M002, LOCTM-M003, and LOCTM-M004 address various compliance requirements and are not classified as compliance-related controls as relevant code sections do not state a time frame for compliance.[158] PG&E asserts that gas operators are allowed to consider the timing of these mitigations in accordance with negotiated general rate case budget, risk, and pace.[159]

Alternatives Analysis

PG&E presents the following two alternative plans:

1. **Alternative Plan 1: LOCTM-A001 – Mitigate Transmission Pipeline Impacted by Climate Change:** This alternative proposes to mitigate impacts of climate change from predicted increases in flooding and heavy precipitation, that might cause coastal flooding, delta levee breaches, landslides, scour near waterways, and erosion hazards. Mitigations include relocating pipelines or hardening through anchoring or concrete coating of at-risk pipelines. This alternative is informed by PG&E's CAVA.[160]

2. **Alternative Plan 2: LOCTM-A002 – Mitigate Transmission Pipeline With Strong Axial Near-Neutral Stress Corrosion Cracking (A-NN SCC) and Selective Seam Weld Corrosion (SSWC) threats:** This mitigation considers replacing pipelines with A-NN SCC and SSWC threats. This program would reduce the risk of A-NN SCC and SSWC damage to transmission pipeline assets, improving the longevity of its steel pipeline system.[161]

Observations:

SPD observes PG&E's analysis of alternative mitigation plans is satisfactory and supports the justifications for not moving forward with the alternative mitigation plans.

CBR Calculations

PG&E calculated CBR values for 29 controls, four mitigations, and the two alternative mitigation plans. Table 2-2 below shows the 2027 through 2030 Program level CBR for all 35 programs.

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158 Compliance requirements that are time-based must be completed within a specified timeframe (e.g. 12 months not to exceed 15 months).

159 PG&E response to SPD Data Request, RAMP-2024_DR_SPD_010-Q001.

160 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 1, page 1-55, lines 5-12.

161 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 1, page 1-58, lines 1-7.

Table 2-2: CBR Summary of all LOCTM Programs

ID	Program	2027-2030 Program CBR
LOCTM-C001	Geo-Hazard Threat Identification and Mitigation	0.00379
LOCTM-C002	LNG/CNG to Support Strength Testing	0.16
LOCTM-C004	Earthquake Fault Crossings	0.0248
LOCTM-C005	In-Line Inspection	5.18
LOCTM-C006	Gas Gathering Divestiture	0.09
LOCTM-C007	Shallow and Exposed Pipe (Including Water and Levee Crossings) - Control	0.00
LOCTM-C008	Pipeline Safety and Reliability	0.02
LOCTM-C009	Locate and Mark - Transmission	111.50
LOCTM-C010	Locate and Mark - Transmission Standby	29.55
LOCTM-C011	Public Awareness	29.29
LOCTM-C012	Required Pipeline Patrol Program	6.50
LOCTM-C013	PM Gas Pipeline Valves Program	0.14
LOCTM-C014	CM Gas Pipeline Valves Program	46.56
LOCTM-C015	Pipeline Marker Maintenance	52.48
LOCTM-C016	Vegetation Management	0.09
LOCTM-C017	Vegetation Manage Project	3.14
LOCTM-C018	Encroachments	1.99
LOCTM-C019	Cathodic Protection	48.03
LOCTM-C020	Transmission Leak Management	4.89
LOCTM-C022	Direct Assessment	0.02
LOCTM-C024	Valve Safety and Reliability	8.59
LOCTM-C026	TIMP Strength Testing	0.03

ID	Program	2027-2030 Program CBR
LOCTM-C027	Pipe Investigations and Field Engineering	7.42
LOCTM-C025	Class Location Change	0.0024
LOCTM-C031	Gas Holder Maintenance	0.08
LOCTM-C032	Internal Corrosion Program	0.07
LOCTM-C033	Electrical Interference Program	3.34
LOCTM-C034	Atmospheric Corrosion Program	1.28
LOCTM-C035	Transmission Corrosion Control Program	0.22
LOCTM-M001	Vintage Pipe Replacement	0.78
LOCTM-M002	Shallow and Exposed Pipe (Including Water and Levee Crossings) - Mitigation	0.03
LOCTM-M003	Non-TIMP Strength Testing	0.04
LOCTM-M004	Valve Automation	0.46
LOCTM-A001	Mitigate Transmission Pipeline Impacted by Climate Change	0.01
LOCTM-A002	Replacement of pipelines with Strong A-NN SCC and SSWC threats	0.23

Observations:

SPD observes that only 15 of 33 (or 45 percent) Controls and Mitigations have a CBR greater than 1.0. None of the four proposed mitigations have a CBR greater than 1.0. PG&E did not explain which controls are related to compliance.

The average CBR of PG&E's 29 proposed controls is 12.44 and the average CBR of PG&E's four proposed mitigations is 0.32. Therefore, the average CBR of PG&E's controls is 38 times higher than the average CBR of its mitigations. PG&E should continue to evaluate whether proposing mitigations with comparatively low CBRs is prudent.

Other Observations

Bare Steel Transmission Pipe:

At the end of 2023, PG&E had 1.1 miles of bare steel transmission pipes. PG&E does not have a program solely focused on addressing bare steel pipes. However, bare steel pipes are a data input into PG&E's risk algorithm pertaining to threat identification in 49 CFR, Part 192, Subpart O. For this reason, bare steel pipes might be replaced depending on the outcome of its risk algorithm pertaining to Subpart O threat identification.[162] The CPUC 2023 Program Evaluation Letter[163] issued by PHMSA encourages identifying and replacing high-risk pipes such as bare steel. SPD recommends PG&E continue to closely analyze whether the remaining 1.1 miles of bare steel pipeline should be replaced.

ESJ Pilot Study and Implementation:

Risk reduction and mitigation spending was estimated for mitigation and control programs across disadvantaged and vulnerable communities (DVC) and non-DVCs. SPD's evaluation of PG&E's workpaper, GO-LOCTM-19_DVC analysis.xlsx,[164] revealed a coding error[165] in PG&E's estimate of natural units according to DVCs and non-DVCs. However, this error was found not to impact the estimate of risk reduction or NPV Spend for the mitigations proposed to be implemented in the DVCs and non-DVCs. PG&E discovered that approximately 26.1 percent of the LOCTM risk is found within DVCs. PG&E has also targeted 28.1 percent of its investment in mitigations in DVCs, accounting for 28.4 percent of all risk reduction PG&E aims to achieve during this GRC cycle.[166]

Summary of Findings

1. Risk contained within each of the 24 tranches varies substantially:
    - 87 percent of the risk is contained within the top six riskiest tranches (2,380 miles or 37 percent of the total exposure for LOCTM):
        - Geohazard Pipe and HCA
        - All Other Pipe and HCA
        - Shallow/Exposed Pipe and HCA
        - Potential Manufacturing Defect Pipe and HCA
        - Potential IC Pipe and HCA
        - Geohazard Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)

162 PG&E's response to SPD Data Request, RAMP-2024_DR_SPD_022-Q005.

163 U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, CAPUC 2023 Program Evaluation Letter.

164 Workpaper: Exhibit PG&E-3, Chapter 1 GO-LOCTM-19_DVC analysis.xlsx.

165 The coding error is found in the "Mileage, risk by DVC" tab in the "GO-LOCTM-19_DVC analysis.xlsx" workpaper, columns AB through AG.

166 For details see the "Summary" spreadsheet in the "GO-LOCTM-19_DVC analysis.xlsx" workpaper.

2. SPD finds LOCTM-M002 and LOCTM-M003 have CBRs that are 1.4-1.5 orders of magnitude lower than a CBR equal to 1.0, and PG&E has not provided enough compelling documentation[156] to use operational and execution considerations as a justification for including these mitigations in its 2024 RAMP application.
3. SPD disagrees with PG&E that LOCTM-M002, LOCTM-M003, and LOCTM-M004 are justified due to risk tolerance since PG&E did not provide workpapers on risk tolerance (e.g., not defining a risk tolerance number or framework).
4. C008 does not estimate risk reduction for the 2028 through 2030 period. PG&E stated in response to SPD's data request RAMP-2024_DR_SPD_004-Q005 that it was unable to estimate risk reduction values for the 2028 through 2030 period.
5. PG&E implicitly includes environmental damage in its financial consequences. PG&E models financial consequences based on PHMSA incident data, including the costs of environmental cleanup and damage.
6. SPD finds that PG&E does not distinguish ruptures or leaks that resulted in an ignition from those that did not for COF categories and consequence classifications. SPD finds significant variance can exist in consequences for risk events with an ignition compared to those with no ignition in High Consequence Areas.
7. SPD finds that PG&E proposes only 63 percent of its proposed mitigation miles in the top six riskiest tranches, which account for 87 percent of the total risk score.[167]

Recommended solutions to address findings and deficiencies

1. SPD recommends PG&E continue to evaluate the proposed scope and scale of LOCTM-M002, LOCTM-M003, and LOCTM-M004 as presented in the 2024 RAMP application. These mitigations are tied to compliance requirements that do not have a specified time frame for compliance. Funding for these mitigations should be carefully evaluated in the 2027 GRC filing.
2. SPD recommends PG&E continue to evaluate the appropriateness of including LOCTM-M002, LOCTM-M003, and LOCTM-M004 as mitigations within its 2027 GRC filing for the reasons outlined in the Summary of Findings in this report regarding the use of operational and execution considerations and risk tolerance as justifications. SPD recommends PG&E provide further justification for factors affecting mitigation selection in its 2027 GRC filing.
3. SPD recommends that PG&E improve risk reduction estimation for C008 for the years 2028 through 2030 as PG&E estimated the cost for those years in the 2024 RAMP filing.
4. SPD recommends the Commission and intervenors thoroughly examine the low CBRs of PG&E's proposed mitigations in the 2027 GRC filing.
5. SPD recommends PG&E propose most of its mitigation work in the highest-risk tranches in its 2027 GRC filing.

[167] SPD Data Request, RAMP-2024_DR_SPD_022-Q004.

6. SPD recommends PG&E continue to closely analyze whether the remaining 1.1 miles of bare steel pipeline should be replaced.
7. SPD recommends PG&E continue to evaluate whether proposing mitigations with low CBRs, when compared against the proposed control's CBRs, is prudent in a safe, reliable, and affordable system.
8. SPD recommends PG&E continue to improve modeling of environmental consequences from a LOCTM event.
9. SPD recommends that, at least for High Consequence Areas, and possibly also for Moderate Consequence Areas, PG&E distinguish whether ruptures or leaks resulted in an ignition for both COF categories and consequence classifications.
10. SPD recommends PG&E provide further justification for the factors affecting mitigation selection in its 2027 GRC filing. If these mitigations with low CBRs are needed to comply with regulatory requirements, they should be identified as such. The relevant regulatory requirements must also be cited.

3. Public Contact with Intact Energized Electrical Equipment (PCEEE)

Risk Description

Public Contact with Intact Energized Electrical Equipment (PCEEE) risk is defined as the risk of a reportable serious injury or a fatality (SIF)[168] to a third-party contractor (non-PG&E employee or PG&E contractor) or member of the public from an interaction with intact PG&E energized electric assets not originating from asset failure. Third-party SIFs resulting from the failure of an electric asset are out of this risk category's scope. Of the 32 risks in PG&E's Corporate Risk Register, PCEEE has the third-highest 2027 Test Year (TY) Baseline Safety Risk Score ($60.1 million) and the fifteenth-highest 2027 TY Baseline Total Risk Score ($60.1 million). Table 3-1 summarizes PCEEE's in-scope and out-of-scope activities.

Table 3-1: Risk Definition and Scope[169]

PUBLIC CONTACT WITH INTACT ENERGIZED ELECTRICAL EQUIPMENT	
Definition	PCEEE is defined as the risk of reportable serious injury or fatality to a third-party contractor or member of the public from an interaction with intact PG&E electric assets that did not originate from asset failure.
In Scope	Reportable third-party (public) serious injuries or fatalities due to interaction with or during the use of a PG&E facility, not involving asset failure.
Out of Scope	Third-party reportable serious injuries or fatalities resulting from the failure of an electric asset. Third-party gas dig-in reportable injuries or fatalities are included as key drivers for Gas Operations Loss of Containment Risks. Non-preventable motor vehicle incidents involving third-party interaction are included in the Motor Vehicle Safety Incident risk. Car (hit) pole events are included as drivers in the Distribution Overhead risk.
Data Quantification Sources	PG&E data including third-party initiated incidents logged in the Integrated Logging Information System (ILIS), Transmission Operation Tracking & Logging tool. Public serious Incidents Reports from PG&E's Risk Master Database, and Electric Incident Reports from 2018 through 2022.

168 A fatality or personal injury requiring in-patient hospitalization involving utility facilities or equipment. Equipment includes utility vehicles used during the course of business. See Decision (D.)19-04-020 and D.21-11-009.

169 PG&E 2024 RAMP, Exhibit PG&E-4, Table 3-1

Table 3-2 shows the PCEEE Drivers and Categorizations from 2018 to 2022. Table 3-3 presents the total count of serious injuries. Notably, PCEEE events declined from six and eight in 2018 and 2019, respectively, to three and one in 2021 and 2022, respectively.

Table 3-2: PCEEE Drivers and Categorizations from 2018 to 2022[170]

Year	Categorization	Driver	Sum of Serious Injury Count
2018	Aircraft	Aircraft	1
2018	Contact with Intact	Non-working activity	1
2018	Contact with Intact	Working activity, 3rd party	3
2018	Dig in, 3rd party	Dig in, 3rd party	1
2018	Tree - cutting, 3rd party	Tree - cutting, 3rd party	0
2018	Vandalism	CC - Physical Attack	0
2019	Aircraft	Aircraft	3
2019	Contact with Intact	Non-working activity	0
2019	Contact with Intact	Working activity, 3rd party	2
2019	Tree - cutting, 3rd party	Tree - cutting, 3rd party	1
2019	Vandalism	CC - Physical Attack	2
2020	Contact with Intact	Non-working activity	0
2020	Contact with Intact	Working activity, 3rd party	1
2020	Dig in, 3rd party	Dig in, 3rd party	0
2020	Tree - cutting, 3rd party	Tree - cutting, 3rd party	3
2020	Vandalism	CC - Physical Attack	1
2021	Contact with Intact	Non-working activity	0

[170] PG&E 2024 RAMP, EO-PCEEE-6_SIF_Incidents_2018-2022.xlsx

Year	Categorization	Driver	Sum of Serious Injury Count
2021	Contact with Intact	Working activity, 3rd party	2
2021	Vandalism	CC - Physical Attack	1
2022	Contact with Intact	Non-working activity	0
2022	Vandalism	CC - Physical Attack	1

Table 3-3: The sum of serious Injury Count from 2018-2022[171]

Year	Sum of Serious Injury Count
2018	6
2019	8
2020	5
2021	3
2022	1

Observations:

PG&E PCEEE events have decreased in recent years from six and eight in 2018 and 2019, respectively, to three and one in 2021 and 2022, respectively. However, SPD notes that the sample size of these risk events is small, and caution must be taken in drawing conclusions from such a small dataset. SPD recommends that PG&E consider using longer historical data or employing Bootstrap Resampling to generate a larger number of samples. Alternatively, Bayesian analysis could be used, which incorporates prior information from previous studies or expert knowledge and updates with observed data to estimate probabilities.

Additionally, since small sample sizes may limit statistical analyses, SPD recommends that PG&E consider augmenting quantitative data with qualitative insights, especially in exploratory research. Patterns and trends from small datasets may be better understood when combined with contextual or qualitative information.

[171] PG&E 2024 RAMP, EO-PCEEE-6_SIF_Incidents_2018-2022.xlsx

Bow Tie

PG&E provides PCEEE risk Bow Tie for TY 2027, as shown in Figure 3-1 below. PCEEE has six drivers including third-party working activities, cross-cutting risk of physical attack, third-party tree cutting services, non-working activity, aircraft contact, and third-party dig-ins. The outcomes are measured in Public SIF.

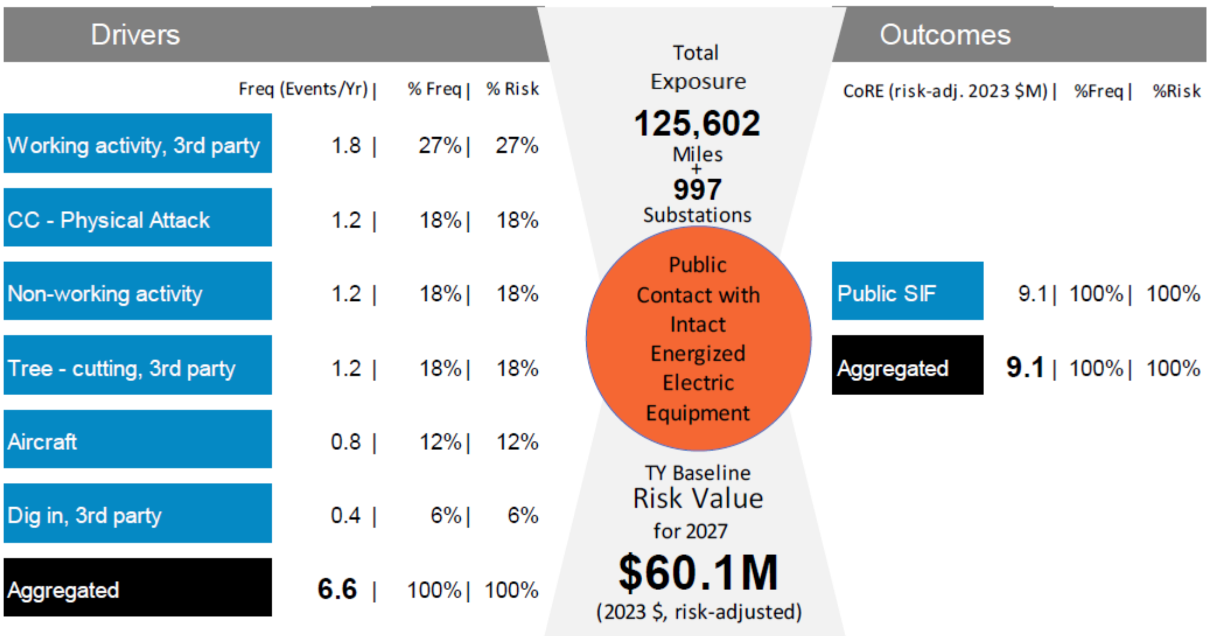

Figure 3-1: PCEEE risk Bow Tie for TY 2027[172]

Observations:

The primary observation here (Bow Tie) is similar to that noted in the Risk section, above: the small sample size limits the ability to draw meaningful conclusions from the statistical analyses. SPD recommends that PG&E consider using other analytical and qualitative methods to supplement the small sample size of risk events available for analysis.

Exposure

Exposure to PCEEE risk is measured across PG&E's service territory, encompassing approximately 125,600 circuit miles, including approximately 80,000 circuit miles of distribution overhead electric lines, 26,000 circuit miles of distribution underground electric lines, 18,000 circuit miles of interconnected transmission lines, and approximately 1,000 electric substations, all of which are within proximity of

[172] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 3, Figure 3-1

interaction for the public. The exposure includes PG&E's 70,000 square mile service territory in northern and central California.

Observations: None.

Tranches

PG&E defines four tranches for PCEEE:

1. Contact with Electric Distribution Overhead Assets (80,000 circuit miles); With approximately 73 percent of the overall risk, the largest drivers to this tranche are associated with third-party work activities, such as crane/boom contact, third-party tree cutting, agricultural activities, and construction activities
2. Contact with Electric Transmission Overhead Assets (18,000 circuit miles): This represents approximately 12 percent of the overall risk. The largest drivers to this tranche are associated with non-work activities involving crane/boom contact and aircraft contact.
3. Contact with Electric Distribution Underground Assets; (26,000 circuit miles): Representing approximately nine percent of the overall risk, the largest driver to this tranche is associated with third-party dig-in events, whether from agriculture or third-party construction activities.
4. Contact with Electric Substation Assets (1,000 electric substations): This represents approximately six percent of the overall risk.

Figure 3-2 below shows the risk exposure list by tranche.

Line No.	Tranche Description	Percent Exposure	Safety Risk Score	Total Risk Score	Percent Risk
1	Electric Distribution Overhead Assets	64%	43.6	43.6	73%
2	Electric Transmission Overhead Assets	15%	7.3	7.3	12%
3	Electric Distribution Underground Assets	21%	5.5	5.5	9%
4	Electric Substation Assets	<1%	3.7	3.7	6%
5	Total	100%	60.1	60.1	100%

Figure 3-2: Risk Exposure by tranche[173]

[173] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 3, Table 3-23

Observations:

SPD observed that 73% of PCEEE risk is within electric distribution assets (such as wildfire risk).

Risk Drivers

PG&E identified six drivers and eight sub-drivers for the PCEEE risk:

D1 – Working Activity, 3rd Party: public contact with PG&E's energized electric overhead facilities;1.8 incidents per year, or 27 percent, of the 6.6 expected annual number of risk events. **D2 – Physical Attack (CCF):** a third party vandalizes or attempts theft associated with PG&E energized equipment; accounted for 1.2, or 18 percent, of the 6.6 expected events each year. **D3 – Non-Working Activity:** contact with overhead energized electrical assets by a member of the public. When work for an established company is not involved, it accounts for 1.2, or 18 percent, of the 6.6 expected events each year. **D4 – Tree-Cutting, 3rd Party;** third-party working in a vegetation management capacity as a non-PG&E contractor; accounted for 1.2, or 18 percent, of the 6.6 expected annual number of risk events. **D5 – Aircraft;** accounted for 0.8, or 12 percent, of the 6.6 expected events each year. **D6 – Dig In, 3rd Party;** accounted for 0.4, or 6 percent, of the 6.6 expected events each year. Figure 3-1 summarizes the PCEEE Drivers and Categorizations from 2018 to 2022.

Observations: None.

Cross-cutting factors

Cross-Cutting Factors; A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E presented seven cross-cutting factors in the 2024 RAMP: climate change, cyber-attack, emergency preparedness and response, IT asset failure, physical attack, records and information management (RIM), and Seismic.

Observations:

SPD observed that of the seven cross-cutting factors; only physical attack impacts the likelihood and has been quantified in the risk models. While RIM might affect the likelihood, it was not quantified in the model.

Consequences

The outcome of Public Contact with Energized Electrical Equipment is a CPUC reportable incident if the event results in either a serious injury requiring overnight hospitalization or a fatality. Reliability and financial attributes are not scoped within this risk.

Observations: The consequence component of PCEEE is driven largely by the Value of Statistical Life (VSL) reflected in the safety attribute of risk. Public contacts with high-voltage energized equipment qualifying for a reportable incident will frequently have reliability impacts, either when circuit protection devices engage as a result of the contacts or when PG&E personnel must de-energize the lines after an incident. Direct financial impacts may occur when a public contact with energized equipment results in damaged equipment. However, the reliability and financial impacts of PCEEE events are usually relatively insignificant compared to the safety impacts.

Controls and Mitigations

Controls

- PCEEE-C001: Locate and Mark (L&M) – Distribution

The L&M Program provides the physical location of PG&E's underground (UG) assets (gas and electric) for PG&E crews, contractors, and third parties who plan to excavate near those assets.

For 2027-2030:

NPV Cost: $231M, Foundational Activity Cost[174] : $8.5M, NPV Risk Reduction=$113M, and CBR=0.5.

- PCEEE-C002 – Public Safety Awareness

Public Safety Awareness provides educational outreach activities for third parties (PG&E customers and non-customers operating in PG&E territory). Communications may include mailers, e-mails, and educational material distribution on safe practices around PG&E assets through proper operation of equipment and excavation practices. The program support includes, but is not limited to, the following areas:

• Third-Party Contractor and Agriculture,

• Tree and Orchard Workers (over 67,000 mailers to third-party vegetation management companies)

• Emergency Preparedness Support Services (to educate first responders)

• School Public Safety Education

[174] Foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events.

For 2027-2030:

NPV Cost: $4.4M, NPV Risk Reduction=$33.6M, and CBR=7.6.

Mitigations

There are no direct mitigations planned during the 2023-2026 timeframe. However, mitigations associated with other electric risks that have secondary benefits to Public Contact with Energized Electric Equipment are presented with their total costs, mitigation benefits, and CBRs considering all the risks they apply to. For example, system hardening has reduction benefits for the wildfire risk, the distribution overhead risk, and the public contact risk. The totals are shown below.

For 2027-2030:

- PCEEE-M002: System Hardening [Overhead]

NPV Cost $449.3M, NPV Risk Reduction=$7,986.9M, and CBR=17.8.

- PCEEE-M003: System Hardening [Underground]

NPV Cost $6,482.6M, NPV Risk Reduction=$51,323M, and CBR=7.9.

Changes to Mitigations from 2023-2026

PCEEE-M001: Additional Signage

This mitigation proposes adding additional signage, pole wraps, or stickers on PG&E poles that would notify the public about the risk above (overhead assets) and below (underground facilities) associated with electrical contact.

NPV Cost $3.18M, NPV Risk Reduction=$3.14, and CBR=1.

Observations:

1. SPD observed that the L&M program is a compliance-related activity designed to provide accurate physical locations of underground assets to prevent accidental contact during excavation. While this control effectively mitigates the risk of third-party dig-ins, it does not fully address broader PCEEE risks, such as direct public contact with overhead energized equipment. To enhance public safety, the Additional Signage mitigation program is proposed by PG&E to add clear and visible signage, pole wraps, or stickers on its poles to alert the public to the risks posed by both overhead electrical assets and underground facilities. This addresses a visibility issue, as mandated signage (e.g., high-voltage signs mounted on poles) is often placed above eye level and may not be easily seen by individuals on the ground. However, both the L&M and Additional Signage programs currently exhibit low cost-benefit efficiencies, with CBRs of 0.2 and 1, respectively. These programs include compliance-related activities and PG&E is required to carry them out regardless of the CBR value.

2. PCEEE-C002 – Public Safety Awareness demonstrates the highest cost efficiency compared to the other mentioned PCEEE mitigations and controls.

Alternatives Analysis

- PCEEE-A001: EPSS non-HFTD

This alternative proposal considers the application of EPSS enablement in non-HFTD areas. This mitigation would not reduce the frequency of events but could decrease the extent of injuries and minimize fatalities by faster tripping of fault currents and length of duration to contact with energized facilities

For 2027-2030:

NPV Cost $481.4M, NPV Risk Reduction=$99.6M, and CBR=0.2.

- PCEEE-A002: Proximity Warning Alarms

This program considers adding proximity warning alarms to third-party cranes and boom operators.

For 2027-2030:
NPV Cost $27.6M, NPV Risk Reduction=$79M, and CBR=2.9.

Observations:

1. SPD observed that alternative mitigation, PCEEE-A001: EPSS non-HFTD, with a CBR of 0.2, is not a cost-efficient measure to reduce the PCEEE risk. Both PCEEE-C002: Public Safety Awareness with a CBR of 7.6, and PCEEE-A002: Proximity Warning Alarms with a CBR of 2.9, exhibit much higher cost efficiencies.

CBR Calculations

Observations: None.

Summary of Findings

1. Although PCEEE events have decreased in recent years (from six and eight in 2018 and 2019, respectively, to three and one in 2021 and 2022, respectively), SPD observed the sample size for PCEEE events is (fortunately) very small. Due to the small sample size, statistical methods may be ineffective for providing meaningful conclusions.
2. SPD observed that of the seven cross-cutting factors only physical attack impacts likelihood and has been quantified in the model. While RIM might affect the likelihood, it has not been quantified.
3. SPD observed that both the Locate and Mark (to provide accurate physical locations of underground infrastructure) and Additional Signage (to add clear and visible signage, pole wraps, or

stickers on its poles) programs exhibit low cost-benefit efficiencies, with CBRs of 0.2 and 1, respectively. PG&E should identify which mitigation activities are compliance-related, including those with a low CBR, so such low values can be assessed in the appropriate context.

4. PCEEE-C002 – Public Safety Awareness demonstrates the highest cost efficiency (CBR=7.6) compared to the other PCEEE mitigations and controls.
5. Alternative Plan 1, PCEEE-A001: EPSS non-HFTD, with a CBR of 0.2 is not a cost-efficient measure to reduce PCEEE risk.
6. Alternative Plan 2, PCEEE-A002: Proximity Warning Alarms, with a CBR of 2.9 exhibits a reasonable cost efficiency with a CBR of 2.9.

Recommended solutions to address findings and deficiencies

1. SPD recommends PG&E consider using longer historical data or employing Bootstrap Resampling to generate a larger number of samples. Alternatively, Bayesian analysis could be used, incorporating prior information (from previous studies or expert knowledge) and updating it with observed data to estimate probabilities.
2. Additionally, since small sample sizes may limit statistical analyses, SPD suggests PG&E consider augmenting quantitative data with qualitative insights, especially in exploratory research. Patterns and trends from small datasets may be better understood when combined with contextual or qualitative information.
3. SPD recommends PG&E consider leveraging advanced technology and innovative solutions, such as real-time mapping, high-precision GIS, and real-time communication tools to improve the efficiency of its mitigation and control programs. These tools could include mobile apps, chat boxes, and digital platforms that allow contractors and the public to quickly request, locate, and view marked areas, thereby streamlining processes and reducing risks more effectively.
4. SPD recommends that PG&E should focus on the mitigations and controls with higher cost-benefit ratios, such as PCEEE-C002 – Public Safety Awareness with a CBR of 7.6 and PCEEE-A002: Proximity Warning Alarms with a CBR of 2.9.
5. PG&E should identify all compliance-related controls and mitigations so that low CBR values can be assessed in the proper context.

4. Failure of Electric Distribution Overhead Assets

Risk Description

This chapter focuses on the Failure of Electric Distribution Overhead (DOVHD) assets, which address safety-related incidents or risk events associated with the failure of PG&E's overhead distribution system. The consequence of the failure of DOVHD assets is primarily driven by indirect safety impacts caused by loss of service, comprising 84 percent of the safety consequence for this risk. Table 4-1 below describes PG&E's risk definition and scope relating to this chapter.

Of the 32 risks in PG&E's Corporate Risk Register, DOVHD assets have the fourth highest 2027 Test Year (TY) baseline safety risk value ($54.4 million) and the second-highest baseline total risk value ($3.354 billion)[175]. Table 4-1 shows the risk definition and scope.

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[175] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-1, lines 11-14.

Table 4-1. Risk Definition and Scope[176]

FAILURE OF ELECTRIC DISTRIBUTION OVERHEAD ASSETS	
Definition	Failure of Electric Distribution Overhead Assets or lack of remote operational functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.
In Scope	Failure of assets associated with PG&E's overhead (OH) electrical distribution system that include: poles and support structures; primary and secondary conductor; voltage regulating equipment; protection equipment; switching equipment; transformers; and PG&E-owned streetlights
Out of Scope	Consequences of any ignitions associated with the failure of the electrical distribution system assets (which are included in the scope of the Wildfire risk). Consequences associated to the increased frequency or duration of sustained outages as a result of EPSS (which are included in the EPSS risk section described in Exhibit (PG&E-4), Chapter 1). Safety consequences associated with the failure of assets due to the activities of PG&E employees, PG&E contractors, and third parties (which are included in the scope of the Employee Safety Incident, Contractor Safety Incident, Public Contact with Intact Energized Electrical Equipment (PCEEE) and Motor Vehicle Incident risks)
Data Quantification Sources	Data associated with the drivers/source of failures and data associated with reliability impact of failures are taken from PG&E's Distribution Overhead (DOH) Outage Dataset from January 1, 2017 to December 31, 2022. Data associated with the safety consequences of failures is taken from PG&E's Electric Incident Reports from January 1, 2015 to December 31, 2022. Safety consequence is based on Electric Incident Reporting dataset which maintains injury/fatality incidents within PG&E service territory. Data associated with the financial impact of failures is taken from PG&E's DOH Restoration Costs Dataset from January 1, 2017 to December 31, 2020.

Observations:

Indirect safety impacts comprise 84 percent[177] of the overall safety risk associated with DOVHD assets. Of that, 78 percent[178] are related to customer minutes interrupted (CMI) from indirect safety risk on Major Event Days (MED). PG&E describes indirect safety impacts as public safety effects of loss of electrical power related to long-duration outages, but does not otherwise describe indirect impacts in detail.[179] PG&E's proposed risk mitigations for DOVHD assets include utilizing drones for visual inspection, sensor technologies, and Artificial Intelligence (AI) for inspection and advanced testing to assess the likelihood of asset failures more accurately. SPD recommends that PG&E discuss these mitigation strategies in more detail in its 2027 General Rate Case (GRC) filing for additional transparency.

Bow Tie

PG&E's failure of electrical distribution overhead assets, shown below in Figure 4-1, represents critical information on drivers, exposure, and outcomes through the risk event analysis.

[176] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-4.
[177] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-1, Lines 27-29.
[178] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-1, Lines 29-33.
[179] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-1, Lines 29-30.

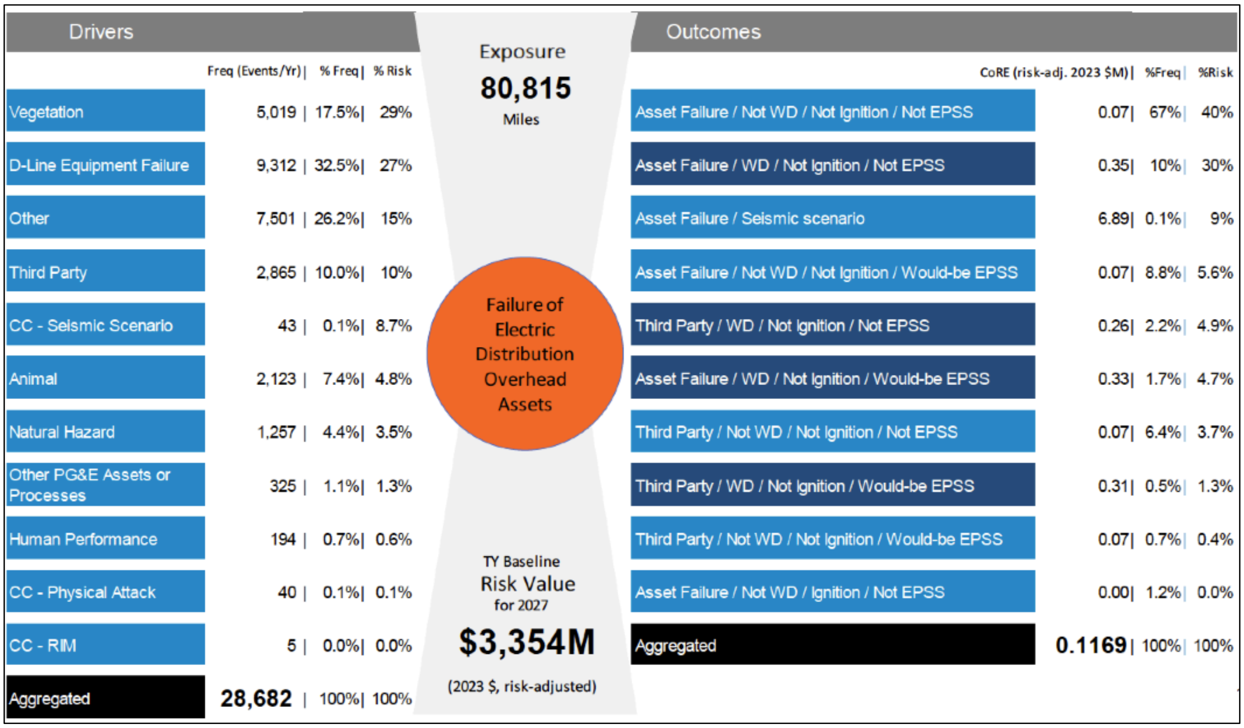

Figure 4-1. Risk Bow Tie[180]

Observations:

SPD found key differences in the risk bow tie analysis between PG&E's 2020 and 2024 RAMP filings. In the 2024 analysis, the Third-Party category is included as both a driver and in the outcomes. In the 2020 analysis, the Third-Party category was absent. Additional granularity in the current bow tie represents the consequences of wire-down events, ignitions, and EPSS. PG&E stated the reliability and financial consequences of EPSS enablement are represented in the wildfire risk, so it does not appear in this chapter. The risk associated to outages during EPSS conditions when EPSS is not enabled is attributed to the Failure of Electric Distribution Overhead Assets risk[181].

Exposure

The exposure for DOVHD risk is expressed in total overhead circuit miles. In the 2024 RAMP, exposure for DOVHD risk is 80,815 circuit miles, as shown in Figure 4-1.

[180] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, Figure 4-1, page 4-6.

[181] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-15.

Observations:

SPD found no significant difference in DOVHD exposure between PG&E's 2020 and 2024 RAMP filings. The 2020 RAMP showed an exposure of 80,716 circuit miles[182] for primary conductor and associated assets compared to 80,815 circuit miles[183] for 2024 RAMP.

Tranches

PG&E grouped DOVHD risk into 20 tranches, 10 for High Fire Threat Districts (HFTD)/High Fire Risk Areas (HFRA) and another 10 for non-HFTD/HFRA.[184]

Observations:

The evolution of DOVHD tranches increased from five tranches in the 2020 RAMP to 20 tranches[185] in 2024, increasing the level of granularity. With this increased granularity, HFTD/HFRA represents 32 percent of the risk, and non-HFTD/HFRA represents 68 percent. SPD had found the tranches were not adequately granular in the 2020 RAMP. Figure 4-2 represents the tranche level of risk analysis.

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182 Safety Policy Division Staff Evaluation Report on PG&E's 2020 RAMP Application (A.) 20-06-012, page 74.
183 PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-6.
184 PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-7, Lines 17-29.
185 PG&E 2024 RAMP Report, Exhibit PG&E-2, Chapter 2, page 2-35.

Tranche	Mileage	Risk Score	% Risk Score	Risk Score/Mile
Non-HFRA_Tranche_01	94	123.7	3.7%	1.32
Non-HFRA_Tranche_02	387	226.9	6.8%	0.59
Non-HFRA_Tranche_03	691	229.1	6.8%	0.33
Non-HFRA_Tranche_04	863	199.4	5.9%	0.23
Non-HFRA_Tranche_05	1,324	211.9	6.3%	0.16
Non-HFRA_Tranche_06	1,863	226.2	6.7%	0.12
Non-HFRA_Tranche_07	2,524	215.9	6.4%	0.09
Non-HFRA_Tranche_08	3,608	228.3	6.8%	0.06
Non-HFRA_Tranche_09	6,958	232.3	6.9%	0.03
Non-HFRA_Tranche_10	36,569	365.9	10.9%	0.01
HFRA_Tranche_01	77	124.9	3.7%	1.63
HFRA_Tranche_02	219	162.2	4.8%	0.74
HFRA_Tranche_03	385	137.6	4.1%	0.36
HFRA_Tranche_04	724	102.2	3.0%	0.14
HFRA_Tranche_05	873	84.2	2.5%	0.10
HFRA_Tranche_06	1,274	94.6	2.8%	0.07
HFRA_Tranche_07	1,941	111.1	3.3%	0.06
HFRA_Tranche_08	2,943	81.4	2.4%	0.03
HFRA_Tranche_09	4,848	79.7	2.4%	0.02
HFRA_Tranche_10	12,651	115.9	3.5%	0.01
Aggregated	80,815	3,353.5	100%	0.04

Figure 4-2. Tranche Level Risk Analysis ResultsRisk Drivers[186]

PG&E identified 11 risk drivers (D1 to D11)[187] for the DOVHD risk in the Risk Bow Tie. Vegetation and Distribution Line Equipment Failure drivers cumulatively account for 50 percent of total risk events or outages, while "Other" risk drivers account for 26.2 percent of 28,683 outages.

Observations:

The "Other" category, comprising 26.2 percent, or 7,501 annual risk events, poses concerns of a potential lack of clarity and/or deficiency in PG&E's risk assessment analysis for DOVHD. SPD recommends that PG&E should provide additional granular details on "Other" categories in its 2027 GRC filing.

[186] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, Table 4-2, page 4-8.
[187] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, pages 4-8 to 4-10.

Cross-Cutting Factors

PG&E presented seven cross-cutting factors (CCF) in the 2024 RAMP. Each CCF is a driver and is incorporated into the Bow Tie. The CCFs may impact the likelihood or consequence of DOVHD and its risk. In two cases (Climate Change and Physical Attack), the factor is not considered to impact consequence, as shown in Table 4-2.

Table 4-2. Cross-Cutting Factors[188]

CCF Name	Impacts Likelihood	Impacts Consequence
Climate Change	Yes	**No**
Cyber Attack	Yes*	Yes*
Emergency Preparedness and Response	Yes*	Yes*
Information Technology (IT) Asset Failure	Yes*	Yes*
Physical Attack	Yes	**No**
Records and Information Management (RIM)	Yes	Yes
Seismic	Yes	Yes

Yes	CCF has been quantified in the model.
Yes*	CCF does not influence the baseline risk but is not quantified in the model, or it may influence the baseline risk, but further study is needed.
No	CCF does not influence the baseline risk.

Observations:

The CCFs are included as risk drivers, but the contributions to total risk are relatively insignificant, as the Risk Bow Tie shows in Figure 4-1.

Consequences

The consequences of PG&E's asset failures due to DOVHD risk events are linked to a combination of event-related outcomes, segregated into the following categories in the RAMP report:[189]

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[188] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, Table 4-3, page 4-12.
[189] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-14, lines 7-10.

- Asset Failure/Third-Party;
- Wire Down (WD)/No WD;
- Ignition/No Ignition; and
- Would be EPSS/Not EPSS

A combination of these categories and a seismic event created sixteen unique outcomes plus an asset failure/seismic cross-cutting outcome[190]. The number of outcomes expands on the four outcomes presented in the 2020 RAMP Report[191]. The likelihood of these events is determined by the relative frequency of historical occurrences that meet the specified criteria. The impact of each event is assessed using a probability distribution that fits each potential outcome. The risk bow tie shown in Figure 4-1[192] illustrates the frequency and risk percentage outcomes for 10 outcomes.

Observations:

SPD observes that PG&E defined some outcome categories differently in the 2020 and 2024 RAMP filings. Specifically, Asset Failure coinciding or not coinciding with IT asset failure was included as a category in the 2020 RAMP but is absent in 2024. SPD recommends that PG&E explain the absence of IT asset failure coincidence as an outcome category in the TY 2027 GRC filing.

Additionally, the 2024 RAMP introduced outcome categories for wire-down and EPSS components that were not present in the 2020 RAMP. The consequences associated with these categories vary significantly. SPD recommends that PG&E explain the changes in category choices between the 2020 and 2024 RAMPs in the TY 2027 GRC filing.

Controls and Mitigations

Controls

Observations:

SPD identified 44 control programs in Table 4-6 of PG&E's 2024 RAMP. SPD noted that 13 of these programs, initiated in the 2020 RAMP, were assigned new identifiers (e.g., C4-OH conductor Replacement becomes DOVHD-C004) by PG&E for the 2023 GRC (2023-2026) period. The new IDs are logical assignments of the risk name to the risk ID.

Mitigations

Observations:

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190 PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-14, lines 11-12.
191 2020 PG&E RAMP Report, Table 11-4.
192 PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-6.

SPD identified 42 mitigation programs in Table 4-7 of the 2024 RAMP. PG&E reassigned new identifier numbers from the 2020 RAMP to some mitigation programs for the 2023 GRC (2023-2026) period, such as control programs.

Alternatives Analysis

PG&E presented two alternative mitigation plans in Tables 4-16 and 4-17 of this distribution overhead RAMP chapter[193] (DOVHD); these are the same alternatives presented in the wildfire chapter that primarily address wildfire risk but have some impact on DOVHD. PG&E gives the alternatives' total cost, risk reduction, and CBR as they apply to the combined risks. A summary is shown below in Table 4-3.

Table 4-3. Alternative Mitigation Costs Comparison Analysis

Alternative Plan	Mitigation ID	Mitigation Name	Millions of Dollars (NPV)			CBR (C)/[(A) + (B)]
			Total Program Cost (2027-2030) (A)	Foundational Activity Cost (B)	Risk Reduction (C)	
1	DOVHD-A001 PCEEE-A003 WLDFR-A001	System Hardening [Underground] (Alternative Workplan)	$6,261.3	$0.0	$60,725.9	9.7
2	DOVHD-A002 WLDFR-A002	Grid Monitoring (Alternative Mitigation)	$87.1	$0.0	$600.2	6.9
Note:	NPV=Net Present Value uses the base year of 2023					

Alternative Plan 1: DOVHD-A001 (the same program as WLDFR-A001 and PCEEE-A003), is an alternative to the proposed System Hardening [Underground] workplan, which aims to reduce ignitions that lead to wildfires but also mitigates the non-ignition risk considered in this distribution overhead chapter. It saves some cost by replacing the undergrounding of Secondary and Service lines with covered conductor hardening but it adds cost by increasing the miles of Primary undergrounding. The alternative also includes

193 PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, Table 4-16, page. 4-47; Table 4-17 page. 4-49.

budget to address other electrical programs, primarily work to reduce pole tags. Alternative 1 has a better CBR (9.7) than the proposed mitigation (7.9) but at about the same cost ($6.26 billion vs $6.48 billion).

A contradictory statement by PG&E is that this alternative proposes fewer underground miles after the 2027 test year, but then describes an increasing number of miles for each year as 500 (2027), 550 (2028), 600 (2029), and 650 (2030)[194]. The alternative miles total 2,300, which is greater than PG&E's proposed total WLDFR-M022/DOVHD-M022 miles of 1,711.

PG&E rejected this alternative for various reasons, including that the allocation to pole tag programs would not provide incremental risk reduction, as explained in their RAMP report.[195]

Alternative Plan 2: DOVHD-A002, Grid Monitoring, is an alternative mitigation considered incremental to the base list of mitigations. PG&E stated this plan could provide better system operational mitigations, distribution overhead asset health, and line and pole-mounted technologies with SmartMeter devices for real-time monitoring capabilities to protect assets from failures. The estimated CBR for this alternative is 6.9. PG&E rejected this alternative due to the additional analysis required to implement failure probabilities based on sensor data, adding that they are considering a pilot program to understand how to process sensor data to perform the intended grid monitoring.[196]

Observations:

Alternative 1 gives a true alternative to the proposed set of mitigations. Alternative 2 would add another program to the base set, but it does not appear viable until a pilot study could develop the concept into an implementable program.

Clearly, the bulk of the risk reduction for Alternative 1 is coming from the grid hardening benefit considered in the wildfire risk chapter as WLDFR-A001. Still, there is some incremental benefit from reducing the non-ignition DOVHD risk of this chapter that contributes to the overall CBR.

Although PG&E rejected both alternatives, SPD recommends that PGE offer a more cost-effective alternative to the proposed grid hardening work plan in the 2027 GRC filing. For example, a combination of more covered conductor and fewer undergrounding miles could achieve a significant level of risk reduction at a lower cost. And PG&E should propose a pilot program to study the implementation of Grid Monitoring sensors in the 2027 GRC.

CBR Calculations

PG&E presented CBR calculations for controls and mitigations. SPD noticed that five of the CBR calculations for controls have a value less than 1.0. Table 4-4 highlights control programs with CBRs less

[194] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page. 4-46, lines 4-9.
[195] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page. 4-45, lines 25-33.
[196] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, page 4-48.

than 1.0, as detailed in Exhibit PG&E-4, Chapter 4, Table 4-12.[197] Table 4-5 highlights seven mitigations with a CBR of less than 1.0, as detailed in Exhibit PG&E-4, Chapter 4, Table 4-15.[198]

Table 4-4. Controls With CBR Less than 1.0

Item No.	Control ID	Control Name	Millions of Dollars (NPV)			CBR
			Total Program Cost (2027-2030) (A)	Foundational Activity Cost (B)	Risk Reduction (C)	(C)/[(A)+(B)]
1	DOVHD-C002, WLDFR-C002	VM Distribution - Second Patrols	221.9	4.8	172.4	0.8
2	DOVHD-C009, WLDFR-C009	Overloaded Transformers Replacement	32.0	-	6.2	0.2
3	DOVHD-C015, WLDFR-C015	Overloaded Pole Replacements	46.2	-	0.8	<0.1
4	DOVHD-C018, WLDFR-C018	Pole Restoration	25.4	-	19.7	0.8
5	DOVHD-C022, WLDFR-C022	Distribution Steady State Maintenance Replacements [KAQ]	2.4	0.2	0.5	0.2
Note:	NPV=Net Present Value uses the base year of 2023					

[197] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, Table 4-12, page 4-40.
[198] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 4, Table 4-15, page 4-43.

Table 4-5. Mitigations with CBR Less than 1.0

Item No.	Mitigation ID	Mitigation Name	Millions of Dollars (NPV)			CBR
			Total Program Cost (2027-2030) (A)	Foundational Activity Cost (B)	Risk Reduction (C)	(C)/[(A)+(B)]
1	DOVHD-M006	Grasshopper and KPF Switch Replacement	4.9	-	0.2	<0.1
2	DOVHD-M012	3A and 4C Line Recloser Replacement [3A]	0.3	-	0.0	<0.1
3	DOVHD-M013	3A and 4C Line Recloser Replacement [4C]	2.4	-	0.1	<0.1
4	DOVHD-M023, WLDFR-M023	Backlog Open Tag Reduction - Distribution (Pole Backlog)	389.1	-	41.5	0.1
5	DOVHD-M024, WLDFR-M024	Backlog Open Tag Reduction - Distribution (Capital) [2AA]	219.7	-	165.2	0.8
6	DOVHD-M026, WLDFR-M026	Pole Programs - Replace Tree Attachments	126.8	-	4.5	<0.1
7	DOVHD-M035	Overhead Conductor Replacement	35.3	-	0.0	<0.1
Note:	NPV=Net Present Value uses the base year of 2023					

Observations:

PG&E did not provide substantial narrative justification for controls and mitigations with CBRs less than 1.0 in this chapter, but made a general statement in Exhibit PG&E-1, Chapter 1, that "under the current RDF, risk mitigation or risk control programs addressing a risk event with potentially serious safety consequences may have an estimated CBR of less than 1.0 simply because the frequency of the risk event is low."[199] SPD notes, for example, that mitigations M-012 and M-013, with CBRs <0.1, propose to replace recloser devices that are not in high safety risk HFTD/HRFA areas but are aimed at improving customer reliability, which doesn't seem to justify spending more than 10 times the risk reduction value based on the narrative. SPD recommends that PG&E provide detailed narrative justifications for controls and mitigations with CBR less than 1.0.

CBR Presentation for Program IDs

PG&E chose to give different Program IDs to the same program if it applied to more than one risk chapter. This can be confusing to the reader when the total results of a program are presented in a chapter that only accounts for a portion of the risk reduction and CBR. Examination of the tranche-level workpapers helps identify the portion of risk reduction attributed to programs that are shared among more than one risk[200]. For example, DOVHD-C001 is a vegetation management program that is also identified as WLDFR-C001 in the wildfire chapter. The combined cost, risk reduction, and CBR for this control are presented with a total CBR of 3.2 in Table 4-12 of the DOVHD chapter, but that represents the sum of applying the program to both the wildfire and the distribution overhead risks. The breakdown of risk reduction from each contributing risk can be found in the workpapers. SPD found the individual contributions to the risk chapters at the tranche level for DOVHD-C001 as an example and summed them in Table 4-6 below.

199 PG&E 2024 RAMP Report, Exhibit PG&E-1, Chapter 1, page 1-14, lines 2-5.

200 PG&E 2024 RAMP Workpaper RM-RMCBR-15, Ramp Mitigations and Controls and their CBRs.

Table 4-6. Total Program CBR Allocation for Multiple Program ID

Risk Evaluated	Program ID (Multiple)	Tranche/Risk Name	Millions of Dollars (NPV)			Risk CBR (C)/[(A)+(B)]	Total Program CBR (D+E)
			Total Program Cost (2027-2030) (A)	Foundational Activity Cost (B)	Risk Reduction (C)		
WLDFR	DOVHD-C001, WLDFR-C001	HFRA_Tranche (01-10) and Non-HFRA_Tranche (01-10)	1978.01	43.01	6209.90	3.0726 (D)	3.2316
DOVHD	DOVHD-C001, WLDFR-C001	HFRA_Tranche (01-10) and Non-HFRA_Tranche (01-10)	1978.01	43.01	321.32	0.1590 (E)	
Note:	NPV=Net Present Value uses the base year of 2023						

Observations:

This analysis indicates that the majority of risk reduction for this control is attributed to wildfire risk reduction, which has a CBR of 3.07 on its own. Applying this control to the DOVD risk adds an incremental risk reduction that would only have a CBR of 0.159 by itself assuming that no wildfire risk exists. But the total benefits add up to a CBR of 3.23. PG&E only presents the combined data in the risk chapters. While a reviewer can eventually find the breakdown of data between different chapters as presented in Table 4-8, SPD recommends that PG&E should provide a clear presentation in the risk chapters to show the contributions of each risk when multiple risks share the same program.

Summary of Findings

1. PG&E's "Other" category, comprising 26.2 percent, or 7,501 annual risk events, poses concerns of a potential lack of clarity and/or deficiency in PG&E's risk assessment analysis for DOVHD.
2. SPD observes that PG&E defined some outcome categories differently in the 2020 and 2024 RAMP filings. Specifically, Asset Failure coinciding or not coinciding with IT asset failure was included as a category in the 2020 RAMP but is absent in 2024.

3. Additionally, the 2024 RAMP introduced outcome categories for wire-down and EPSS components that were not present in the 2020 RAMP. The consequences associated with these categories vary significantly.
4. SPD reviewed the alternative mitigation plans. Only Alternative 1 offers an alternative to the proposed grid hardening work plan. Alternative 2 offers a potential incremental mitigation beyond the base proposal but does not appear to be ready for deployment without doing a pilot first.
5. In this chapter, PG&E did not provide substantial narrative justification for mitigations and controls with CBRs less than 1.0.
6. Some control and mitigation programs are identified with different IDs depending on the risk they are applied to. When this type of program produces benefits for multiple risks, PGE does not indicate the individual risk benefit contribution to the total benefit in the risk chapters, but only the aggregate total.

Recommended solutions to address findings and deficiencies

Based on the findings and deficiencies in this chapter, SPD recommends PG&E to address the following:

1. SPD recommends that PG&E provide additional granular details on "Other" categories in its 2027 GRC filing.
2. SPD recommends that PG&E should explain the absence of IT asset failure coincidence as an outcome category in the TY 2027 GRC filing. Additionally, PG&E should explain the changes in category choices between the 2020 and 2024 RAMPs in the TY 2027 GRC filing.
3. SPD recommends that PGE offer a more cost-effective alternative to the proposed grid hardening work plan in the 2027 GRC filing. For example, a combination of more covered conductor and fewer undergrounding miles could achieve a significant level of risk reduction at a lower cost. And PG&E should propose a pilot program to study implementation of Grid Monitoring sensors in the 2027 GRC.
4. SPD recommends that PG&E provide detailed narrative justifications for controls and mitigations with CBR less than 1.0 in the 2027 GRC filing.
5. When a single program has risk benefit application in more than one chapter, SPD recommends that PG&E should present in the 2027 GRC filing the allocations of risk reduction from each risk in addition to the overall costs and benefits of the program.

5. Electric Transmission Systemwide Blackout

Risk Description

The Electric Transmission Systemwide Blackout (BLKOT) risk is defined as the risk of a systemwide disturbance leading to a cascading event that causes a blackout of PG&E's electrical system, with the inability to restore the grid in a timely fashion. BLKOT covers PG&E's entire transmission network and downstream distribution assets in the event of a cascading blackout. The risk can be triggered by a single outage or a combination of outages on the transmission system, leading to a complete systemwide outage.

BLKOT is one of two new RAMP risks for the 2024 RAMP largely due to the inclusion of the potential indirect safety consequences associated with long-duration loss of electric service.

Table 5-1: Risk definition and Scope

ELECTRIC TRANSMISSION SYSTEMWIDE BLACKOUT	
Definition	A system wide disturbance leading to a cascading event that causes a blackout of PG&E's electrical system, with the inability to restore the grid in a timely fashion.
In Scope	A single outage or combination of outages on the transmission that lead to a complete systemwide outage.
Out of Scope	Outages (including cyber attack) that affect multiple regions or divisions of PG&E territory but do not lead to system wide outage. Rotating blackouts (i.e., the term used when each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders). Storm events that affect PG&E assets over the course of multiple days through multiple territory do not qualify as cascading blackouts.
Data Quantification Sources	Data associated with the drivers/source of failures and data associated with reliability impact of failures are taken from PG&E's Distribution Overhead Outage Dataset from January 1, 2015 to December 31, 2019. Data associated with the safety consequences of failures is taken from PG&E's Electric Incident Reports from January 1, 2015 to December 31, 2019. Data associated with the financial impact of failures is taken from PG&E's DOH Restoration Costs Dataset from January 1, 2017 to September 30, 2019.

BLKOT ranks as the fourth-highest safety risk and the third-highest total risk score for the 2027 Test Year (TY) of PG&E's 32 Corporate Risk Register risks. The TY 2027 Baseline Safety Risk Score is $51.8 million, and the TY 2027 Baseline Total Risk Score is $1.9 billion.

Observations:

SPD finds that, in response to DR No. SPD_008-Q001 and in their 2nd Errata Notice[201], PG&E corrected their description of data as follows:

> Data associated with the drivers/sub-driver of risk events are based on historical DOE-417 events[202] and US cascading widespread blackout events from 2010 to 2022.
>
> Data associated with reliability impact of risk events are taken from PG&E's SME's estimation of blackstart restoration time.
>
> Data associated with the financial impact of failures is taken from PG&E's PSPS event cost assumptions on the cost of a risk event as a function of the number of customers impacted.

SPD finds that PG&E DOE-417 event data was utilized for individual Grid Emergency Sub-Drivers and the data is from 2010 through 2022 or 13 years.[203]

In response to DR No. SPD_008-Q002, inquiring why PG&E used 2010 as the cutoff point, PG&E explained:

> "PG&E uses 2010 as the cutoff point to best represent the likelihood [of] the current regulatory environment. As stated in the NERC History book[204], two sets of pivotal NERC standards adopted in 2008 addressed issues from the August 2003 northeast blackout. Also stemming from the 2003 blackout, the electric industry approved revised standards for operating personnel training that required the use of a systematic approach to training and a more rigorous and structured framework for developing and delivering operator training. The 2003 Northeast Blackout event would have been mitigated given the current NERC reliability standards. Note, however, that the 2003 Northeast Blackout event and the resulting fatalities and CMI are still used in PG&E's modeling of the indirect safety consequence of this risk.

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201 Email from Hannah Keller HXKY@pge.com on 9/13/2024 4:43pm to A.24-05-008 service list, subject "A.24-05-008 PG&E RAMP: 2nd Errata notice".

202 The U.S. Department of Energy (DOE) and the North American Electric Reliability Corporation (NERC) require Form DOE-417 Electric Emergency Incident and Disturbance Report filing on electric incidents and emergencies. ISER - Electric Disturbance Events (DOE-417)

203 EO-BLKOT-1_Risk Model Input File.

204 The History of the North American Electric Reliability Corporation by David Nevius, Senior Vice President 1979-2012, 2nd Edition March 2020, pages 99-100 available at: https://www.nerc.com/news/Documents/NERCHistoryBook.pdf

PG&E reviewed NERC reports since 1965 to comprehensively capture the high-level primary contributing elements for cascading outages, namely, a utility's inability to respond to a grid emergency, multiple asset failures across the transmission systems, and lack of generation and increased demand on the BES [Bulk Electric System] for which ISO and the utility could not compensate for. These contributing elements do not focus on the specifics of the cause and apply universally in years pre and post 2010. Using NERC reports since 1965 and using 2010 as the cutoff point are to the benefit of assessing this risk."

SPD confirmed the reference to the two sets of pivotal NERC standards in the NERC History Book[205]:

- "PRC-023-1 – Transmission Relay Loadability addressed the expected settings of load sensing relays to ensure they did not operate undesirably during a system event. Following the blackout, events involving relays of this type significantly decreased, and this standard helped ensure continued emphasis on this issue."
- "In August 2013, the Board adopted PRC-025-1 – Generator Relay Loadability under Phase 2 of the Relay Loadability project. This three-phase project addressed FERC Order 733, which directed NERC to address three areas of relay loadability that included modifications to the approved PRC-023-1, development of a new standard to address generator protective relay loadability, and development of another standard to address the operation of protective relays due to power swings."

SPD finds that 2010 is an appropriate cutoff point for risk modeling purposes due to significant NERC regulatory improvements made after the 2003 Northeast Blackout.

In response to SPD_008-Q003, PG&E explained that Third Party 'Foreign Object' incidents were excluded in the risk analysis because they tend to have short duration and/or localized scale of impact and therefore are unlikely to cause systemwide blackout events. SPD finds that it was appropriate for PG&E to exclude Third Party 'Foreign Object' incidents in its risk analysis due to their typical short duration and/or localized scale of impact.

[205] *Id.*

Bow Tie

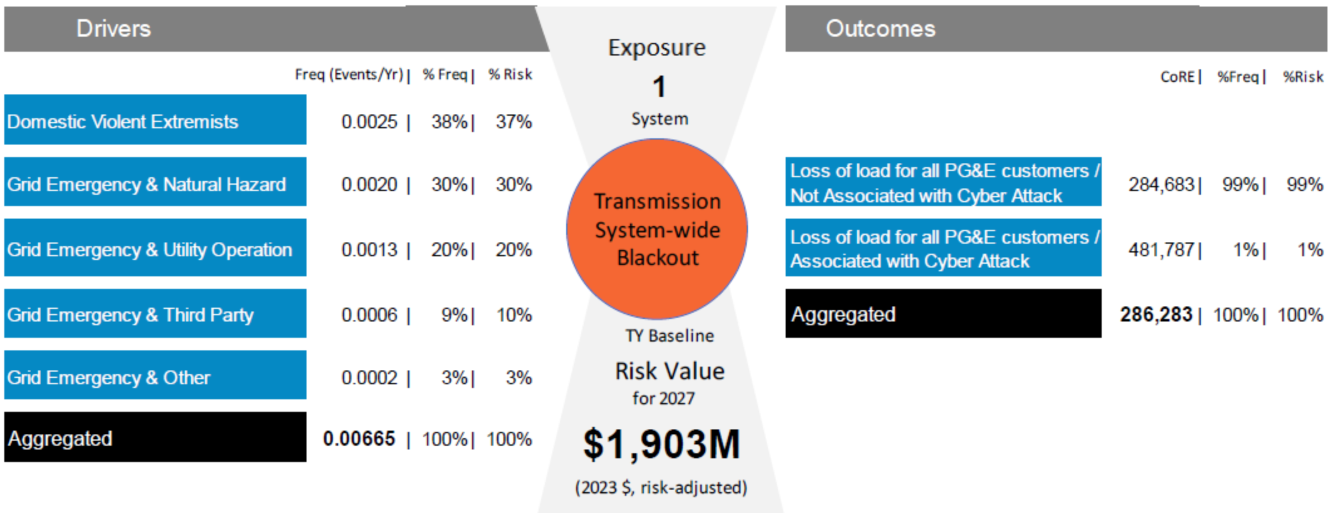

Figure 5-1 – PG&E's Electric Transmission Systemwide Blackout Risk Bow Tie

Observations:

SPD finds that aggregated Frequency (Events/Yr) for Drivers of 0.00655 multiplied times aggregated Outcomes (CoRE) of 286,283 equals $1,903M shown in Figure 1, PG&E's Electric Transmission Systemwide Blackout Risk Bow Tie.

Exposure

Exposure to this risk is based on the complete loss of load for all PG&E customers (5.7 million) for an extended outage lasting at least 2-3 days. Hence, exposure to the BLKOT risk is represented by a unit count of 1, as the event reflects a binary situation.

Observations: While the risk definition of a system-wide blackout defines the exposure as the complete loss of the system, there could be value in dividing the transmission assets into various exposure segments especially since PG&E has a very large territory.[206] SPD recommends that PG&E divide its territory into multiple sections of its transmission grid to model large transmission outages in future risk modeling even if these are not system wide blackouts.

[206] https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_MAPS_Service%20Area%20Map.pdf

Tranches

From PG&E's review of NERC reports for causes of cascading systemwide blackouts and non-cascading widespread blackouts across North America since 1965, the following three primary elements were determined to contribute to cascading outages:

1. A utility's inability to respond to a grid emergency;
2. Multiple asset failures across the transmission systems; and
3. Lack of generation and increased demand on the Bulk Electric System (BES) for which the Independent System Operator (ISO) and the utility could not compensate for.

PG&E is reluctant to discuss the criticality of specific transmission assets in open settings, due to the increased national trend of Domestic Violent Extremists (DVE) attacks. PG&E has a system that is in accordance with NERC Critical Infrastructure Protection (CIP) policies. PG&E claims that openly discussing what specific assets are more likely to lead to a cascading blackout would provide a roadmap to a BLKOT that could be used by bad actors in physical and cyber domains. Hence, PG&E identified only one tranche associated with the BLKOT risk: the entire transmission network system and downstream distribution assets.

Observations:
SPD finds that PG&E only utilized only 1 tranche for their entire system.[207] Like the Exposure section recommendation, SPD recommends that PG&E divide their large service territory into multiple tranches to model risks for specific transmission assets.

Risk Drivers

While PG&E has not experienced a cascading BLKOT event, other utilities across North America and California have experienced a BLKOT event in the last 20 years. The five drivers identified by PG&E for BLKOT risk reflect a combination of events and consist of:

1. Domestic Violent Extremists (DVE);
2. Grid Emergency & Natural Hazard;
3. Grid Emergency & Utility Operation;
4. Grid Emergency & Third-Party; and
5. Grid Emergency & Other.

Grid Emergency events account for 63 percent of the overall 2027 TY risk. A coordinated and sustained attack on specific Critical Infrastructure Protection (CIP) assets by DVEs accounts for 37 percent of the remaining risk.

[207] EO-BLKOT-1_Risk Model Input File.xlsm, Tab 3-Tranche

The Cybersecurity risk was explicitly modeled in Electric Transmission Systemwide Blackout as a driver/outcome combination. This modeling represents the potential for a cyber-attack to cause grid emergency conditions and reflects the longer recovery time of such an emergency. The likelihood estimate is based on a review of a dataset of historical grid emergencies and U.S. widespread blackouts that included cyber-attack information and the degree to which such an event is prolonged is informed by SME judgment.

Observations:

SPD calculated 1-in-X years for each Sub-Driver Frequency included in Table 5-2. SPD finds that the sub-driver frequencies are infrequent, with DVE estimated to be the most common with a systemwide blackout event every 1-in-400 years. SPD finds that Cyber Attack is projected to be the least common sub-drivers with a systemwide blackout event every 1-in-25,000 years. SPD recommends PG&E reevaluate if these frequencies are adequate assumptions for risk modeling purposes and specifically whether the Grid Emergency & Cyber Attack frequency is adequate.

Table 5-2: Frequencies by Sub-Driver

Sub-Driver	Frequency	1-in-X Years
Grid Emergency & Wind	0.00024	4,167
Grid Emergency & Equipment Failure	0.00085	1,176
Grid Emergency & Human Performance	0.00044	2,273
Grid Emergency & Physical Attack	0.00053	1,887
Grid Emergency & Unknown	0.00020	5,000
Domestic Violent Extremists	0.00250	400
Grid Emergency & Cyber Attack	0.00004	25,000

Risk Driver Frequencies

PG&E considered the likelihood of various extreme weather events, which when combined with other issues could cause a risk event. To reflect the impact of these changing climate conditions on this risk, PG&E used climate projections to determine how the frequency of these natural hazard sub-drivers could change over time and impact the frequency of risk occurrence.

Observations:

In response to SPD_008-Q004, PG&E explained its climate multipliers in its workpaper[208]. PG&E explained that its 0.075 escalation parameter for Cyber Attack sub-driver frequency means that it increases 7.5% per year. PG&E also explained that all drivers except DVE and Grid Emergency & Cyber Attack are impacted by climate change. SPD recommends that PG&E further evaluate the risk driver frequencies, specifically reconsidering whether 7.5% annual increase for Cyber Attack is appropriate.

Outcome Frequencies

A Cyber Attack can cause a grid emergency and can extend the expected restoration time relative to a non-cyber grid emergency. This is modeled as a Driver frequency Extracted from Existing mapped to unique Outcome.

Observations:

Outcome frequencies in Bowtie are the same as % Risks. In Bowtie, although Cyber Attack is only 1% of Outcome Frequency and 1% of Outcome Risk, SPD finds it has a larger CoRE than for all non-Cyber Attack outcomes.

Climate Adaptation Vulnerability Assessment (CAVA) Results

In the Blackout Chapter, PG&E states they assessed the impact to PG&E's transmission assets as required through CAVA. PG&E commented they did not assess future climate hazard impacts and climate risks specifically associated with a BLKOT event, which is not a CAVA requirement.

Observations: None.

Cross-cutting factors

All seven cross-cutting factors (CCFs) impact the BLKOT risk event. Three of these CCFs – Cyber Attack, Physical Attack, and Seismic – have been captured in the documentation supporting nationwide Department of Energy OE-417 and are explicitly quantified as risk drivers impacting likelihood in the model.

The fourth, Climate Change, is also quantified as a risk driver impacting likelihood in the model. PG&E incorporates escalating event frequency over time due to three natural hazards: extreme heat events, extreme rain events (e.g., atmospheric rivers), and wildfire.

208 EO-BLKOT-1_Risk Model Input File.xlsm, Tab REF-CC and Tab 5-FreqMult.

Observations:

SPD finds that Seismic (SSMIC), Climate (CLIMT), Cyber Attack (CYBER) and Physical Attack (PHYSA) are included in risk modeling.[209] In response to SPD_008-Q008, PG&E explains two cross-cutting mitigations (M1 Prevent and M2 Detect) for PG&E's Physical Attack CCF are included in the Blackout risk input files where risk reduction benefits exist. SPD confirmed that two rows are active with 0.305% Effectiveness for M2 Detect for Grid Emergency & Physical Attack and for Grid Emergency & Cyber Attack. And two other rows are active with 0.32% effectiveness for M1 Prevent for Grid Emergency & Physical Attack and Grid Emergency & Cyber Attack.[210]

Additionally, SPD finds that climate escalations for Heat, Wildfire, Rain and Heat-Wildfire are from 2023 through 2122.[211]

Consequences

Consequence for BLKOT is primarily driven by reliability impacts, with the outcomes reflecting a loss of load for all PG&E customers associated with (and not associated with) cyber attacks. Loss of load not associated with cyber attacks accounts for 99 percent of the overall risk and frequency, which reflects a consequence of risk event value of $284.68 billion.

Based off the historical review of systemwide blackouts, PG&E believes indirect safety consequences may correlate with exposure of the elements (extreme heat or extreme cold) and carbon-monoxide poisoning. PG&E assumes approximately six fatalities per billion Customer Minute Interruptions (CMI) as described in Exhibit (PG&E-2) Chapter 2, Section C.2.a.

			Natural Units Per Event			Monetized Levels (2023 $M) of a Consequence Per Event			CoRE			Natural Units per Year			Expected Loss per Year (2023 $M/yr)			Attribute Risk Score (2023 $M/yr, risk-adjusted)		
	CoRE | %Freq | %Risk	Freq	Indirect Safety EF/event	Electric Reliability MCMI/event	Financial $M/event	Indirect Safety $M/event	Electric Reliability $M/event	Financial $M/event	Indirect Safety $M	Electric Reliability	Financial	Indirect Safety EF/yr	Electric Reliability MCMI/yr	Financial $M/yr	Indirect Safety	Electric Reliability	Financial	Indirect Safety	Electric Reliability	Financial
Loss of load for all PG&E customers / Not Associated with Cyber Attack	284,683 | 99.2% | 98.6%	0.0066	75	12,347	449	1,139	39,139	449	7,744	275,792	1,147	0.5	81	3.0	8	258	2.96	51	1,818	7.56
Loss of load for all PG&E customers / Associated with Cyber Attack	481,787 | 0.8% | 1.4%	0.00005	124	20,404	449	1,883	64,679	449	13,299	467,342	1,147	0.01	1.10	0.02	0.10	3.49	0.02	0.72	25	0.06
Aggregated	286,283 | 100% | 100%	0.0066	75	12,412	449	1,145	39,347	449	7,789	277,347	1,147	0.5	83	3.0	8	262	2.99	52	1,844	7.62

Figure 5-2 – PG&E Consequence Table[212]

Observations:

[209] See EO-BLKOT-1_Risk Model Input File Tab 2- BowTie.

[210] EO-BLKOT-1_Risk Model Input File, Tab 10-ProgramFreqEff & Tab REF_FreqEff.

[211] EO-BLKOT-1_Risk Model Input File, Tab 12-esc_method.

[212] PG&E Workpaper EO-BLKOT-2_Bow tie, Tab Conseq and also in PG&E 2024 RAMP Table 2-3, Risk Event Consequences on p. 2-11.

SPD finds that PG&E defined the distribution of Consequences for each Risk Event.[213] Distributions and parameters are listed as shown in Figure 5-3 below. SPD finds that PG&E provided the source for Electric Reliability consequence of 12.3468 billion CMI.[214] SPD finds that PG&E calculated Electric Reliability consequence for CyberAttack using 24 hours incremental restoration time.[215]

Outcome	Sub-Attribute	Active	Distribution1	Distribution1_Prob	Distribution1_param1
Loss of load for all PG&E customers / Not Associated with Cyber Attack	Electric Reliability	TRUE	Deterministic	1	12,346,762,500.00
Loss of load for all PG&E customers / Not Associated with Cyber Attack	Financial	TRUE	Exponential	1	370,511,265.15
Loss of load for all PG&E customers / Not Associated with Cyber Attack	Indirect Safety	TRUE	Deterministic	1	12.35
Loss of load for all PG&E customers / Associated with Cyber Attack	Electric Reliability	TRUE	Deterministic	1	20,403,523,734.29
Loss of load for all PG&E customers / Associated with Cyber Attack	Financial	TRUE	Exponential	1	370,511,265.15
Loss of load for all PG&E customers / Associated with Cyber Attack	Indirect Safety	TRUE	Deterministic	1	20.40

Figure 5-3 – PG&E Outcome Distribution & Parameters

SPD finds that PG&E calculated Indirect Safety using 6 EF/BillionCMI (BCMI), resulting in PG&E calculating 12.35 EFs for Indirect Safety not associated with Cyber Attack and 20.40 EFs for Indirect Safety associated with Cyber Attack.[216] In response to SPD_008-Q005, PG&E addressed SPD's concern that this may double count electric reliability impacts into indirect safety impacts stating:

> "PG&E quantified the impact of electric reliability using the Lawrence Berkeley National Laboratory (LBNL) Interruption Cost Estimate (ICE) Calculator, version 1.0. This is a value-based planning tool[217], where the value of reliability is determined based on the potential *economic* losses that customers might experience due to outages."

PG&E also quoted LNBL's clarification on this point:

> "Measures of the added value of service reliability include reported economic losses (net of benefits) and measurements of customer's willingness-to-pay to avoid service unreliability or their willingness-to-accept compensation for it. These measures of the added value of service reliability do not measure all the societal benefits that result from reliability improvements. They do not, for example, account for

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[213] In EO-BLKOT-1_Risk Model Input File.xlsm, Tab 6- Conseq.

[214] Tab REF-Conseq, EO-BLKOT-8_Blackstart Restoration Time_CONFIDENTIAL.

[215] *Id.*

[216] *Id.*

[217] A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys, Ernest Orlando Lawrence Berkeley National Laboratory, November 2003, https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf

> such benefits as improved public safety or public health that result from avoided widespread electric service interruptions. Such societal benefits must be incorporated separately." [218]

Hence, SPD finds that PG&E's electric reliability modeling does not double count indirect safety impacts.

SPD met with PG&E to understand how Financial consequences were calculated using data in EO-BLKOT-1_Risk Model Input File Tab REF_Conseq. See snapshot of relevant data below. SPD finds that the $66.22 per customer (slope) was multiplied times the number of PG&E electricity customers, or 5,594,973 customers, for the value of 370,511,265.[219] SPD finds that this value is escalated to get to the Financial value of $449M/event in Figure 5-2 above.

Financial

Modeled as [intercept] + [slope] x [# of customers]
where intercept and slope comes from the linear regression of an PSPS event cost by number of customers, and
# of customers come from the system wide blackout events, which is total number of PG&E's customers.

Cost = Slope * [# of Customers] + Intercept	Distribution	Mean	Prob	
Slope * # customers	Exponential	370,511,265	1	slope
Intercept	Deterministic	5,214,986	1	Execution Cost

		Source	Sheet	Notes
$/customer (Slope)	66	EO-WPSPS-1	REF_Conseq sheet	PSPS Financial Cost, slope
$/event (Intercept)	5,214,986	EO-WPSPS-1	REF_Conseq sheet	PSPS Financial Cost, intercept

SPD finds that inflation rates and multipliers are used to convert to 2023 dollars.[220] SPD finds that the Financial Attribute utilized 1.186557 escalation.[221]

SPD inquired about how PG&E applies risk scaling and PG&E responded to DR No. SPD-008-Q006:

> "Consistent with Row 7 of the D.22-12-027 Appendix A (RDF), risk scaling is applied on a per-event basis to the Monetized Levels of an Attribute to obtain the Risk-Adjusted Attribute Levels...
>
> The columns titled "Natural Units Per Event in [Figure 2], represent the non-monetized expected consequences. These are multiplied by the monetization factor to obtain the expected monetized values, titled "Monetized Levels (2023, $M) of a Consequence Per Event in [Figure 2]. It is not possible to determine from this column which risk-scaling factor to apply because the scaling is applied per-event, i.e, to the monetized consequence distribution itself, not to its expected value. Applying the risk-scaling in this manner results in monetized, risk-scaled/risk-adjusted consequence distributions (Risk-Adjusted Attribute Levels) whose expected values are shown in the columns titled "CoRE".
>
> The risk-scaled/risk-adjusted value is found by multiplying the event frequencies (column "Freq") by the "CoRE" columns, as shown in the columns "Attribute Risk Score (2023, $M/yr, risk-adjusted)". The columns titled [Natural Unit per Year and] "Expected Loss per Year (2023, $M/yr)" show the expected

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218 Estimated Value of Service Reliability for Electric Utility Customers in the United States, Ernest Orlando Lawrence Berkeley National Laboratory, June 2009, https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf, p.xv

219 The $66.22/customer is not rounded in the workpaper.

220 EO-BLKOT-1_Risk Model Input File Tab REF_ConseqMult with source File RM-RMCBR-5.

221 Tab REF-Conseq, EO-BLKOT-8_Blackstart Restoration Time_CONFIDENTIAL

non-risk-scaled, i.e., risk-neutral values. PG&E has provided these values at its discretion to add transparency to its analysis and aid parties in understanding the overall impacts of risk-scaling."

Controls and Mitigations

PG&E's transmission system structure has multiple redundancies and controls in place to prevent an outage from spreading in a cascading event that may affect the entire grid, with one mitigation in place for transmission wide blackout.[222] PG&E has several independent controls, some of which are in conjunction with the California Independent System Operator (CAISO), that have proved effective in preventing a BLKOT event.

Regulatory agencies, such as Federal Energy Regulatory Commission, North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and CAISO, have already instituted procedures and policies to prevent a cascading blackout. This includes redundant Grid Control Centers, where situational awareness of the BES is maintained by highly-trained operators capable of conducting load curtailment and coordination with CAISO/WECC to maintain the grid. In the unlikely event of a cascading blackout, PG&E also has independent Blackstart Resources to restart the electrical grid.

PG&E maintains the following seven control programs to help avoid a cascading blackout and restore service to the grid, but there are no plans to change the controls between 2027 and 2030.

1. **BLKOT-C001 – Hydroelectric Blackstart Resources:** Results in complete system restoration of customers in three to five days. PG&E has three independent systems to ensure diversity of recovery options along three major Northern California rivers: Kings River, Feather River, and Pit River.
2. **BLKOT-C002 – Bay Area Blackstart Resources:** In 2017, PG&E procured two additional Blackstart capable resources in the Bay Area through the CAISO Blackstart and System Restoration Phase 2 Initiative. PG&E estimates they can reduce overall customer restoration times by up to 50%, though they are not managed directly by PG&E. These resources do not rely on hydroelectric power. In conjunction with hydroelectric Blackstart Resources, PG&E estimates system restoration can occur in two to three days.
3. **BLKOT-C003 – PG&E Load Curtailment:** PG&E's Electric Emergency Plan (EEP) is an organized approach to implement CAISO load reduction orders in a safe and responsive fashion to preserve the overall system reliability. The EEP makes a good faith effort to be equitable by applying CPUC's customer prioritization orders and by providing for a rotation of outages.
4. **BLKOT-C004 – Redundant Grid Control Center:** PG&E has two completely independent and redundant control rooms to ensure seamless monitoring and control of the PG&E transmission grid: Vacaville Grid Control Center and Rocklin Grid Control Center.

[222] In response to DR No. SPD_008-Q007 and in PG&E 2024 RAMP 2nd Errata, PG&E corrects an error in the RAMP on page 2-2-12 lines 3-4 stating there are no mitigations for this risk. Email from Hannah Keller HXKY@pge.com on 9/13/2024 4:43pm to A.24-05-008 service list, subject "A.24-05-008 PG&E RAMP: 2nd Errata notice".

5. **BLKOT-C005 – Underfrequency Load Shedding (UFLS) and Remedial Action Schemes (RAS):** PG&E maintains its underfrequency relays according to the WECC Off-Nominal Frequency Load Shedding Plan, which aims to enhance system reliability against frequency decline. PG&E also employs various Remedial Action Schemes (RASs) to mitigate a variety of thermal, voltage, and stability concerns, with the most complex schemes focusing on overall WECC stability, including generation and load shed actions.
6. **BLKOT-C006 – CAISO and PG&E Coordinated Functional Registration Agreement:** Operational control of PG&E's transmission grid is shared between CAISO and PG&E, with CAISO serving as the balancing authority and transmission operator, while PG&E executes switching actions and monitoring, both entities ensuring reliability through coordinated mitigation efforts.
7. **BLKOT-C007 – Operations Personnel Training:** This program enhances skills for situational awareness and safe operations, ensures all personnel maintain NERC certification and authority to act, and includes annual system restoration drills to simulate blackouts and response work to safely restore power, emphasizing communication, knowledge sharing, and validation of system restoration guidelines.

PG&E identifies one mitigation for the BLKOT risk:

1. **BLKOT-M001 – Site Hardening**: Based on the security improvements identified through site surveys from PG&E's Corporate Security team, PG&E continues to invest in site hardening activities at different substation sites.

Observations:

In response to SPD_008-Q009, PG&E stated they "did not calculate CBRs or risk reduction values for the Electric Transmission Systemwide Blackout Controls and Mitigations, whose funding request is not through the GRC". PG&E stated the reason is that the RAMP filing purpose is related to the utility's GRC application filing.[223] SPD finds that PG&E did not conduct risk mitigation cost benefit analysis for its controls and mitigation. SPD finds that the Commission established the Transmission Project Review (TPR) Process effective January 1, 2024, in Resolution E-5252. SPD finds that E-5252 stated: "For transmission Stakeholders to have a clear sense of the assumptions used in planning, prioritizing, and approving transmission projects, the TPR Process will include information on whether and how each transmission owner has applied the most current RDF to each project."[224] SPD finds that E-5252 Attachment B "E-5252 Draft Transmission Project Review Process Data Template in an Accompanying Excel File" includes the data field requirements for CBR data from the RDF/RAMP as Field 66 Cost-Benefit Analysis. SPD

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[223] D.14-12-025 Findings of Fact 27: "The purpose of the RAMP filing will be to review the utility's RAMP submission for consistency and compliance with its prior S-MAP, and to determine whether the elements contained in the RAMP submission can be used in the utility's GRC filing to support its positions on the assessment of its safety risks, and its plans to manage, mitigate, and minimize those risks in the context of the utility's upcoming GRC application filing."

[224] Resolution E-5252 page 12.

recommends that PG&E conduct risk modeling for the identified controls and mitigations irrespective of the funding authorization jurisdiction and specifically to be utilized in the TPR Process. SPD also recommends that PG&E divide the BLKOT-M001 Site Hardening Mitigation into multiple mitigations for specific substation sites.

Alternatives Analysis

The following two alternative mitigation strategies were considered to address this risk.

1. **Alternative Plan 1: BLKOT-A001 – Additional Site Hardening:** Site hardening considers security improvements to reduce the likelihood of successful DVE attacks. Based on PG&E's previous Metcalf distribution substation attack and the recent uptick of attacks on other utilities, PG&E identified security improvements that can be adapted to other critical transmission substations at an accelerated pace.
2. **Alternative Plan 2: BLKOT-A002 – Additional Situational Awareness for Operations Personnel:** This plan expands capabilities to improve existing monitoring and to strengthen response readiness. Two options were considered: a) Implement enhanced Operational Tools; and b) Increase Operational Support Personnel.

Observations:

In response to SPD_008-Q010, PG&E stated they "did not calculate CBRs for transmission related programs for RAMP outside of those tied to PG&E 2023-2025 Wildfire Mitigation Plan." PG&E stated the reason is that the RAMP filing purpose is related to the utility's GRC application filing.[225] SPD finds that PG&E did not conduct risk mitigation cost benefit analysis for its two alternative mitigation strategies. SPD recommends that PG&E conduct risk modeling for the alternative mitigation strategies irrespective of the funding authorization jurisdiction and specifically to be utilized in the TPR Process. SPD recommends that PG&E divide the BLKOT-A001 Additional Site Hardening Mitigation into multiple mitigations for specific substation sites. SPD recommends PG&E divide BLKOT-A002 into two separate mitigations for Enhanced Operational Tools and Increased Operational Support Personnel.

CBR Calculations including Inputs/Assumptions

Observations:

SPD recommends that PG&E conduct risk modeling, including cost benefit ratio calculations, for the identified controls and mitigations and alternative mitigations irrespective of the funding authorization jurisdiction.

[225] *Id.*

Summary of Findings

1. SPD finds that, in response to DR No. SPD_008-Q001 and in their 2nd Errata Notice, PG&E corrected their description of data. SPD finds that PG&E DOE-417 event data was utilized for individual Grid Emergency Sub-Drivers in and the data is from 2010 through 2022 or 13 years.
2. SPD finds that 2010 is an appropriate cutoff point for risk modeling purposes due to significant NERC regulatory improvements made after the 2003 Northeast Blackout.
3. SPD finds that it was appropriate for PG&E to exclude Third Party 'Foreign Object' incidents in its risk analysis due to their typical short duration and/or localized scale of impact.
4. SPD finds that aggregated Frequency (Events/Yr) for Drivers of 0.00655 multiplied times aggregated Outcomes (CoRE) of 286,283 equals $1,903M shown in Figure 1, PG&E's Electric Transmission Systemwide Blackout Risk Bow Tie.
5. SPD finds there could be value in dividing the transmission assets into various exposure segments especially since PG&E has a very large territory.
6. SPD finds that PG&E only utilized only 1 tranche for their entire system.
7. SPD finds that the sub-driver frequencies are infrequent, with DVE estimated to be the most common with a systemwide blackout event every 1-in-400 years. SPD finds that Cyber Attack is projected to be the least common sub-drivers with a systemwide blackout event every 1-in-25,000 years.
8. In Bow tie, although Cyber Attack is only 1% of Outcome Frequency and 1% of Outcome Risk, SPD finds that it has a larger CoRE than for all non-Cyber Attack outcomes.
9. For cross-cutting factors, SPD finds that Seismic (SSMIC), Climate (CLIMT), Cyber Attack (CYBER) and Physical Attack (PHYSA) are included in risk modeling. SPD finds that climate escalations for Heat, Wildfire, Rain and Heat-Wildfire are from 2023 through 2122.
10. SPD finds that PG&E defined the distribution of Consequences for each Risk Event.
11. SPD finds that PG&E provided the source for Electric Reliability consequence of 12.3468 billion CMI. SPD finds that PG&E calculated Electric Reliability consequence for CyberAttack using 24 hours incremental restoration time.
12. SPD finds that PG&E calculated Indirect Safety using 6 EF/BillionCMI (BCMI), resulting in PG&E calculating 12.35 EFs for Indirect Safety not associated with Cyber Attack and 20.40 EFs for Indirect Safety associated with Cyber Attack. SPD finds that PG&E's electric reliability modeling does not double count indirect safety impacts.
13. SPD finds that the $66.22 per customer (slope) was multiplied times the number of PG&E electricity customers, or 5,594,973 customers, for the value of 370,511,265. SPD finds that this value is escalated to get to the Financial value of $449M/event.
14. SPD finds that inflation rates along with multipliers are used to convert to 2023 dollars and finds that the Financial Attribute utilized 1.186557 escalation.
15. SPD finds that PG&E did not conduct risk mitigation cost benefit analysis for its controls and mitigation.
16. SPD finds that the Commission established the Transmission Project Review (TPR) Process effective January 1, 2024, in Resolution E-5252.

17. SPD finds that E-5252 stated: "For transmission Stakeholders to have a clear sense of the assumptions used in planning, prioritizing, and approving transmission projects, the TPR Process will include information on whether and how each transmission owner has applied the most current RDF to each project."[226]
18. SPD finds that E-5252 "Attachment B E-5252 Draft Transmission Project Review Process Data Template in an Accompanying Excel File" includes the data field requirements for CBR data from the RDF/RAMP as Field 66 Cost-Benefit Analysis.
19. SPD finds that PG&E did not conduct risk mitigation cost benefit analysis for its two alternative mitigation strategies.

Recommended solutions to address findings and deficiencies

1. SPD recommends that PG&E divide its territory into multiple sections of its transmission grid to model large transmission outages in future risk modeling even if they are not systemwide blackouts.
2. Similar to the Exposure section recommendation, SPD recommends PG&E divide their large service territory into multiple tranches.
3. SPD recommends PG&E reevaluate if the assumed frequencies are adequate for risk modeling purposes and specifically whether the Grid Emergency & Cyber Attack frequency is adequate.
4. SPD recommends that PG&E further evaluate the risk driver frequencies, specifically reconsidering whether 7.5% annual increase for Cyber Attack is appropriate.
5. SPD recommends that PG&E conduct risk modeling for the identified controls and mitigations irrespective of the funding authorization jurisdiction and specifically for the TPR Process.
6. SPD recommends that PG&E divide the BLKOT-M001 Site Hardening Mitigation into multiple mitigations for specific substation sites.
7. SPD recommends that PG&E conduct risk modeling for the alternative mitigation strategies irrespective of the funding authorization jurisdiction and specifically to be utilized in the TPR Process.
8. SPD recommends that PG&E divide the BLKOT-A001 Additional Site Hardening Mitigation into multiple mitigations for specific substation sites.
9. SPD recommends PG&E divide BLKOT-A002 into two separate mitigations for Enhanced Operational Tools and Increased Operational Support Personnel.
10. SPD recommends that PG&E conduct risk modeling, including cost benefit ratio calculations, for the identified controls and mitigations and alternative mitigations irrespective of the funding authorization jurisdiction.

[226] Resolution E-5252 page 12.

6. Contractor Safety Incident

Risk Description

This primary risk encompasses actions and factors which may cause a serious injury or death to an individual performing work in the field as one of the 29,000 contractor workers retained by PG&E to support its gas and electric operations. Such work is considered to be high- or medium-risk in character. Specifically, this risk entails a fatality or injury requiring inpatient hospitalization resulting from incorrect operation of equipment or failure to adhere to a Commission rule or standard. Note that this risk excludes asset-failure incidents, addressed elsewhere within the PG&E RAMP Report. Also, note that the PG&E measures are aimed at overseeing the contractor's safety practices; individual contractors provide more direct safety programs for their workers.

Table 6-1: Risk Definition and Scope

CONTRACTOR SAFETY INCIDENT	
Definition	Any event resulting in a contractor serious injury or fatality as defined by PG&E's SIF Standard, which is aligned with the EE International SCL Model Contractors in scope for this risk are those contractors who perform high risk and medium risk work for PG&E. EEI, SCL Model available at: https://www.safetyfunction.com/scl-model
In Scope	PG&E contractors who perform high or medium risk work as defined by the Contractor Safety Standard. PG&E contractor SIF incidents that are not the result of an asset failure. Public serious injuries or fatalities as defined by the CPUC resulting from a Contractor Safety incident. A SIF Actual (Public) is defined as a fatality or personal injury requiring inpatient hospitalization for other than medical observations that an authority having jurisdiction has determined resulted directly from incorrect operation of equipment, failure or malfunction of utility-owned equipment, or failure to comply with any California Public Utilities Commission (CPUC or Commission) rule or standard. Equipment includes utility or contractor vehicles and aircraft used during the course of business. PG&E employee serious injuries or fatalities resulting from a Contractor Safety incident.
Out of Scope	PG&E contractor serious injuries or fatalities resulting from the failure of an asset or equipment malfunction.
Data Quantification Sources	PG&E SIF (Potential and Actual) investigation reports (2020 to Q2 2023). ISNetworld (ISN) contractor hours (2020 through Q2 2023) ISN is a vendor that specializes in contractor safety prequalification and supplier management data. ISN's data is based on the contractor's working for PG&E. PG&E Public SIF Actual data from the CPUC Safety and Operational metrics reports.

Observations:

In the Executive Summary, PG&E states[227] that the contractor safety risk analysis excludes risk to contractor personnel from PG&E asset failure. The risk is limited to serious injuries or fatalities (SIF) resulting from work performed by the contractor personnel. However, there is conflicting text in Table 1-1[228] which on one line reinforces that in-scope risk covers "PG&E contractor SIF incidents that are not the result of an asset failure" but then later defines the scope of a SIF to include "failure or malfunction of utility-owned equipment." This conflict is not acknowledged or explained, leading to some confusion by the reader as to just how to interpret PG&E's regulatory filing. This evaluation will proceed with the assumption that the scope does exclude asset failure, but it notes that discrepancies in the text lead can lead to confusion.

Bow Tie

Observations:

PG&E offers a Bow Tie risk schematic encompassing just three risk drivers (inadequate safety standard and oversight, lack of pre-qualification, and physical attack), resulting in two outcomes (actual and potential serious injury/ fatality). PG&E's Bow Tie indicates a risk exposure of approximately 40 million annual contract-partner-hours-worked, with a baseline Risk Score of $38.6 million (2023 dollars) for the four-year period beginning in 2027.

The risk score is based on a SIF outcome cost of $9.2 million, along with an expected 33.3 events per year. Later, within the tranche discussion, PG&E explains that 13 percent of the Contractor risk category's risk events are sustained, while the remaining 87 percent of incidents are characterized as safety events that transpired but were at least partially averted so that no SIF consequence is associated with those averted incidents. Accordingly, the aggregated outcome, presented in the Bow Tie is $1.2 million.

From the Bow Tie, one would expect to find the baseline risk score as the product of frequency times outcome (LoRE times CoRE),[229] or 33.3 events per year times $1.2 million per event = $39.9 million. However, the risk score presented is different at $38.6 million. The reason appears to be that the CoRE value in the Bow Tie has been truncated to $1.2 million; one can find a more precise value in the Consequences Table[230] for CoRE of $1.16 million. When the $1.16 value is multiplied by the 33.3 frequency, the Bow Tie risk score is obtained. This kind of discrepancy leads to confusion and necessitates cross-referencing with tables to confirm the values presented are consistent.

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227 PG&E RAMP Report p. 1-1, line 10.

228 PG&E RAMP Report Table 1-1, p.1-3.

229 LoRE = Likelihood of Risk event, expressed as events/year. CoRE = Consequence of Risk Event, in dollars.

230 PG&E RAMP Report, Figure 1-5, p. 1-12 [Consequence Table].

Figure 6-1, PG&E RAMP Employee Safety Bow Tie[231]

Exposure

Observations:

PG&E presents risk exposure as the number of contract-partner-hours-worked – 40,001,279. However, this value conflicts with a larger number of contractor employee work hours-- 43.67 million hours[232] -- cited earlier in the chapter (p. 1-3, line 4). This discrepancy should be explained or corrected in PG&E's 2027 GRC filing.

Tranches

Observations:

Compared with the 2020 RAMP, PG&E has increased the number of tranches from one to four.

Vegetation Management (or VM) is one of the four Tranches PG&E employs for its Contractor Safety risk, the remaining three being electric assets work, gas assets work, and driving on paved roads. PG&E doesn't explain its reasoning for carving out a Tranche category specifically for VM, and thereby creating a second Tranche category also pertinent to electric assets. Given that VM work is among the most dangerous work

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[231] PG&E 2024 RAMP Report, Figure 1-1, p. 1-6 [Bow Tie]

[232] PG&E verified and corrected annual contract-partner-hours-worked is more than 40.00 million hours or 40,001,279 to be exact. Source: Data Request response submitted September 16, 2024.

done by utility workers,[233] it could reasonably infer that VM work alone is responsible for a share of risks comparable to or exceeding that of the other three tranches.

PG&E's Tranche assignments and corresponding share of risk events, as presented in PG&E's Table 1-3,[234] bear out this assumption. Because of errors[235] discovered within Table 1-3, this discussion offers the corrected values, confirmed by PG&E, and shown in below in Table 6-2. The corrected values are: (1) VM, accounting for 34 percent of all Contractor safety occurrences, is responsible for the most frequency of death and serious injury (or, more specifically, *expected annual number of events*); followed by (2) driving on paved-roads with 33 percent; (3) electric work done in the field with 30 percent; and (4) gas work done in the field with 3 percent.

Table 6-2: Corrected Tranche Percentages, Contractor Safety Risk Chapter

Tranche	Electric Work/Job Site	Vegetation Management	Transportation (On-Road Motor Vehicle Use)	Gas work/Job Site
Percentage Share of Risk Events	30	34	33	3

Risk Drivers

Observations:

In comparison with the 2020 RAMP, PG&E has changed the definitions of risk drivers. In 2020, PG&E identified nine risk drivers based on the OSHA-recordable classifications in ISNetworld (ISN) aligned to the

233 The U.S. Bureau of Labor Statistics (BLS) does not track utility vegetation management as its own category, with relatively limited workforce numbers nationally, the employment category may be too specific to enable a national statistical survey. Still, one can apply data available within existing tangential labor categories to triangulate a proxy approximation of the elevated danger inherent in VM work. 1. Utility Line Workers are 5.4 times as likely to die on the job than Americans on average in other occupations; 2. Landscapers are 5.2 times as likely to suffer a fatality; and 3. Loggers die on the job at a rate almost 27 times higher than the average American occupation and serve in the *second most dangerous line of work of all U.S. jobs* according to the BLS. More at: https://www.urbint.com/blog/why-utility-vegetation-management-is-one-of-the-most-dangerous-jobs-in-america

234 PG&E RAMP Report, Table 1-3, p. 1-8

235 The percentages in Table 1-3 added up to more than 100 percent.

contractor's OSHA recordable injuries and illnesses for PG&E work. The current set of three risk drivers make sense from the viewpoint of assigning causes leading to SIFs that can be influenced directly by mitigations.

Consequences

Observations:

PG&E's approach to outcomes assigns a consequence value based on whether an injury result would be actual or potential, based on a Safety Classification and Learning (SCL) model[236] created by the Edison Electric Institute (EEI). The model provides that 13 percent of potentially injurious incidents result in an actual injury or fatality (SIF) while the remainder of incidents do not have a SIF result. The scope of the contractor risk chapter only includes incidents that could produce SIFs (financial consequences such as worker's compensation are incurred by the contracting companies). Thus, it makes sense that the SIF consequence score of $9.2 million is assigned to 13 percent of the incidents while the remainder do not have a SIF consequence assigned. These two categories are aggregated to produce a CoRE value of $1.16 million[237] (1.16 is 13 percent of $9.2 million, as 87 percent of incidents have no SIF consequences). See Figure 6-2.

TABLE 1-5
RISK EVENT CONSEQUENCES

Consequences					Natural Units Per Event	Monetized Levels (2023 $M) of a Consequence Per Event	CoRE (risk-adjusted 2023 $M)	Natural Units per Year	Expected Loss per Year (2023 $M)	Attribute Risk Score (risk-adjusted 2023 $M)
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Safety $M	Safety	Safety EF/yr	Safety $M/yr	Safety
Actual Serious Injury or Fatality	9.2	13%	100%	4.2	0.60	9.19	9.20	2.53	38.58	38.60
Potential Serious Injury or Fatality	-	87%	0%	29.1	-	-	-	-	-	-
Aggregated	1.2	100%	100%	33.3	0.08	1.16	1.16	2.53	38.58	38.60

Figure 6-2. PG&E RAMP Table 1-5, Consequence Table

236 SCL Model available at: <https://www.safetyfunction.com/scl-model>

237 CoRE value of 1.16 million in PG&E RAMP Report Table 1-5, p. 1-12.

Controls and Mitigations

Observations:

PG&E describes 25 control measures, two of which are foundational, grouped into three programs. PG&E puts forward no new mitigation measures. Four current mitigation measures are proposed to continue as mitigations into the 2027 GRC period. PG&E details several past and existing mitigation programs that would all cease operation or revert to a control measure prior to 2027.

Alternatives Analysis

Observations:

PG&E presents two alternative mitigation plans. Each alternative plan contains all of the proposed set of measures, plus one incremental measure. A CBR is provided for one measure but not the other. An alternative plan should consider removal and/or replacement of some proposed measures with the corresponding tradeoffs of risk reduction, to demonstrate that significant alternative choices were considered.

CBR Calculations

Observations:

The CBR is the ratio of risk reduction benefits divided by cost. PG&E presents aggregated CBRs for three control programs rather than for each measure. The three control programs have CBRs ranging from 7.1 to 36.6. For mitigations, the individual measure CBRs are provided, ranging from 1.2 to 12.1. To support informed decision-making, the CBRs of all measures should be provided. The overall four-year cost is fairly modest at $12.1 million considering the baseline risk score of $38.6 million.

Summary of Findings

1) PG&E's Contractor Safety risk chapter contains discrepancies in numbers presented and the definition of risk scope.
2) The Alternatives Analysis plan should include CBR for all options.
3) PG&E aggregates the cost, risk reduction, and CBR of numerous control measures into three program groups.

Recommended solutions to address findings and deficiencies

1) PG&E should do a deeper alternative plan analysis to demonstrate that the proposed plan provides the best balance of cost and risk reduction compared to alternative portfolios of controls and mitigations.
2) PG&E should present the CBR data for each individual control measure.

7. Employee Safety Incident

Risk Description

The primary risks associated with Employee Safety encompass the actions and factors that may result in serious[238] injury or death, and minor safety incidents, to PG&E employees. PG&E employs approximately 25,000 field and office employees to support its generation, gas, and electric operations.

Table 7-1: Risk Definition and Scope

EMPLOYEE SAFETY INCIDENT	
Definition	Any event resulting in: (1) a serious injury or fatality as defined by PG&E's SIF Standard which is aligned with the EEI SCL model or (2) a DART incident as defined by the OSHA.
In Scope	PG&E employee SIFs including DART cases that are not the result of an asset failure. Public SIFs (California Public Utilities Commission (CPUC or Commission)-reported Public SIF Actuals) resulting from an Employee Safety incident. A SIF Actual (Public) is defined as a fatality or personal injury requiring inpatient hospitalization for other than medical observations that an authority having jurisdiction has determined resulted directly from incorrect operation of equipment, failure or malfunction of utility-owned equipment, or failure to comply with any CPUC rule or standard. Equipment includes utility or contractor vehicles and aircraft used during the course of business. PG&E contractor serious injuries or fatalities resulting from an Employee Safety incident.
Out of Scope	PG&E employee SIF and/or DART incidents that are the direct result of a PG&E asset failure or equipment malfunction are excluded from the Employee Safety Incident risk.
Data Quantification Sources	PG&E data including: PG&E Human Resources (HR) Report (2018-2022). PG&E California Division of Occupational Safety and Health (Cal-OSHA)-recordable DART case data by claim cause category Incident Detail Report (2018-Q2 2023) PG&E SIF (Potential and Actual) Investigation Reports (2018–Q2 2023)

Bow Tie

Observations:

Certain minor injuries are qualified according to existing Federal worker-protection regulatory standards known as Days Away, Restricted, or Transferred (DART) which measures recordable incidents per 100 full-time employees that necessitate time off work, assignment to restricted duties, or reassignment to different positions. A qualifying minor injury that triggers a DART action is one where a worker suffers a resulting impairment that rises to a level of necessitating missed work or limited work activities. PG&E's out-of-

238 Injury requiring inpatient hospitalization.

scope disclaimer states that a qualifying serious injury or fatality (SIF) does not involve asset failure but stems from incorrect equipment operation or a violation of a CPUC regulatory rule or safety standard.

PG&E offers a Bow Tie risk schematic[239] encompassing 13 risk drivers, resulting in three outcomes: a DART-qualifying minor injury, a serious injury or fatality, and an unspecified "other" category. PG&E's Bow Tie shows its 24,737 employees as the exposure element and monetizes this risk at a value of approximately $39.1 million (2023 dollars). Assuming an annual work year of 2,080 hours, the total number of annual hours worked by PG&E's workforce is 51.45 million, equating to an Employee Safety risk per-hour cost of $0.76. PG&E's Employee Safety Risk Bow Tie is reproduced below as Figure 7-1.

For each risk category incident, PG&E's Bow Tie indicates a weighted average outcome of $0.10 million per incident, with 378 qualifying safety incidents per year and an expected Risk Value of $37.8 million. However, this result is inconsistent with the $39.1 million Risk Value figure presented in PG&E's Bow Tie diagram. The Risk Value of $39.1 million is derived from PG&E's Table 3-4,[240] which gives the frequency value as 378.01 and the Consequence of Risk Event (CoRE) aggregated value as $0.103 million. For better clarity, the outcome values should not be truncated to two digits so that the CoRE value of 0.103 was readily apparent as the reason for the Risk Value of $39.1 million. PG&E's Table 3-4 is reproduced as Figure 7-2 below.

Another mismatch between the Bow Tie and Table 3-4 is in the presentation of the "%Freq" data. In the Bow Tie, SIFs are presented as 0.5 percent of outcomes, and All Other is presented as 3.4 percent. In Table 3-4, those values are truncated to 0.0 for SIFs and 3.0 for All Other. In one case, the Bow Tie truncates a more precise figure in Table 3-4, while the opposite occurs in another.

A potential inconsistency in the Bow Tie is the value presented for Unknown/unassigned - DART events at 356.0 events per year. The value presented in Table 3-4 for DART events is 363.3 events per year. The value in Table 3-4 is uncertain as it is unclear whether all DART events are included rather than only unknown/unassigned events.

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239 PG&E 2024 RAMP Report, Figure 3-1, p. 3-10 [Bow Tie]

240 PG&E 2024 RAMP Report, Table 3-4, p. 3-18 [Table 3-4].

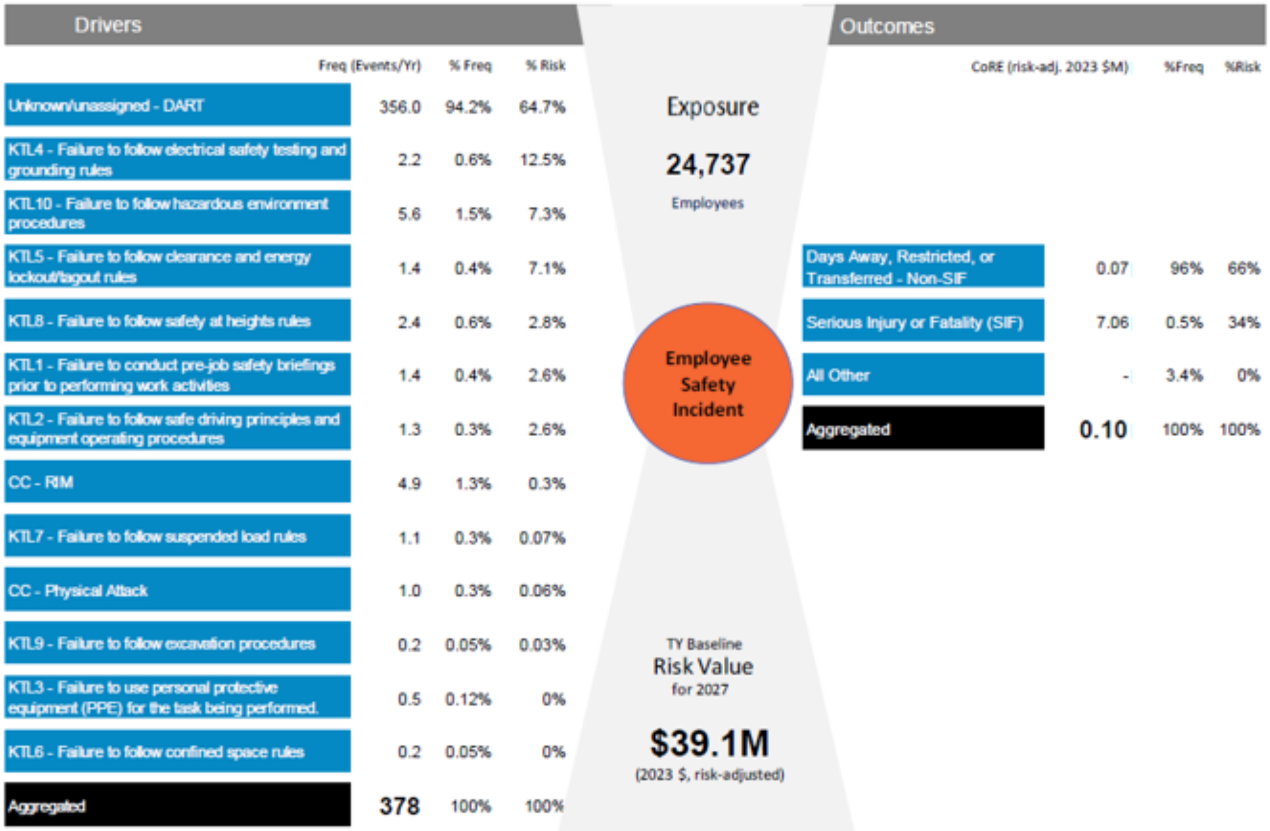

Figure 7-1, PG&E RAMP Employee Safety Bow Tie[241]

[241] PG&E 2024 RAMP Report, Figure 3-1, p. 3-10 [Bow Tie]

TABLE 3-4
RISK EVENT CONSEQUENCES

Consequences					Natural Units Per Event		Monetized Levels (2023 $M) of a Consequence Per Event		CoRE (risk-adjusted 2023 $M)		Natural Units per Year		Expected Loss per Year (2023 $M)		Attribute Risk Score (risk-adjusted 2023 $M)	
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Financial $M/event	Safety $M	Financial $M	Safety	Financial	Safety EF/yr	Financial $M/yr	Safety $M/yr	Financial $M/yr	Safety	Financial
Days Away, Restricted, or Transferred - Non-SIF	0.07	96%	66%	363.2	0.003	0.025	0.046	0.025	0.046	0.025	1.090	9.222	16.596	9.222	16.6	9.2
Serious Injury or Fatality (SIF)	7.06	0%	34%	1.9	0.462	0.018	7.040	0.018	7.040	0.018	0.871	0.034	13.272	0.034	13.272	0.034
All Other	-	3%	0%	12.9	-	-	-	-	-	-	-	-	-	-	-	-
Aggregated	0.1035	100%	100%	378.01	0	0	0.079	0.024	0.079	0.024	1.961	9.256	-	-	29.868	9.256

Note: For additional detail see Exhibit (PG&E-2), Chapter 2.

Figure 7-2. PG&E RAMP Employee Safety Risk Consequence Table[242]

SPD observes that the difference in the expected degree of harm between applicable DART minor injuries and that for SIFs are separated by two orders of magnitude. DART injuries are assigned a CoRE of just $0.07 million (or $70,000) per incident (with an expected 363.2 incidents per year, according to Table 3-4),[243] while SIFs are assigned a CoRE of $7.06 million per incident (with an expected frequency of roughly 1.9).

Exposure

Risk exposure and associated risk scores for each tranche is presented in Figure 7-3 below.

[242] PG&E RAMP Report, Table 3-4, p. 3-18 [Table 3-4].

[243] Table 3-4.

TABLE 3-2
RISK SCORE AND EXPOSURE BY TRANCHE
(MILLIONS OF DOLLARS)

Line No.	Tranche	Percent Exposure	Safety Risk Score	Financial Risk Score	Aggregated Risk Score	Percent Risk Score
1	Field Employees – Electric Operations	17%	$12.7	$2.8	$15.5	40%
2	Field Employees – Gas Operations	13%	8.3	3.1	11.4	29%
3	Field Employees – Other	6%	4.6	1.0	5.6	14%
4	Field Employees – Generation	2%	0.3	0.2	0.5	1%
5	Office Employees	62%	4.0	2.2	6.2	16%
6	Total	100%	$29.9	$9.3	$39.2	100%

Figure 7-3. PG&E RAMP Employee Safety Risk Score and Exposure, PG&E Table 3-2[244].

Observations:

PG&E assigns the Risk Exposure of its 24,737 employees, with 38 percent assigned as field-based and 62 percent office-based.

Tranches

Observations:

In the 2020 RAMP evaluation, SPD recommended that the Employee Safety risk should have more granular tranches, since it was divided into only one tranche for all field workers and one for office workers. In the 2024 RAMP PG&E has expanded the number of tranches to four for different fieldwork categories.

Of the five Tranches PG&E identifies for its Employee Safety risk in Figure 7-2 above, four are directed toward workers in the field who are exposed to risks associated with utility equipment, with the fifth Tranche encompassing the entirety of PG&E's office-based workforce.

PG&E explains that office workers face lower workplace hazard risks – typically falls, sprains, or ergonomic injuries – than the more severe hazards encountered by workers in the field.

Risk Drivers

Observations:

[244] PG&E RAMP Report, Table 3-2, p. 3-11

Employee Safety risk includes 13 risk drivers, ten of which apply to workers in the field, one driver encompassing all office-based employees, and two cross-cutting drivers. The four highest risk-share drivers account for 91.6 percent of risk percentage. The largest driver – Unknown/unassigned DART injuries -- accounts for 64.7 percent of all risk (and 94.2 percent of frequency), and the top two combined account for 77.2 percent of total risk.

Some driver contributions have minimal percentages of total risk, such as the physical attack driver, at only 0.06 percent. That percentage is based on a low expected frequency of events, at 1.0 event per year.

Of the 378 total days away/frequency incidents, 12.9 are described as "All Other" in Table 3-4, or 3.4 percent of incidents. However, no CoRE consequence value is shown for the All Other category , while DART and SIF incidents do show a CoRE value). Presumably, these 12.9 incidents are included as part of the risk drivers that contribute to the total of 378 incidents in the Bow Tie. The absence of a consequence score is not explained in the RAMP narrative. There is no contribution to the consequence score from this driver category and yet the total risk score includes these incidents when multiplying Likelihood of a Risk Event (LoRE) by the CoRE value to obtain the risk score. SPD recommends explaining this missing information in the RAMP and GRC narratives.

Consequences

Observations:

PG&E separates outcomes into three consequence categories: DART minor injuries, SIF, and All Other. A large difference was observed in outcome consequences between the DART consequences of $0.07 million and SIF consequences of $7.06 million per incident. This difference is reasonable when considering the high value placed on fatalities and serious injuries in the CPUC RDF framework of about $13 million per statistical life, while only minor injuries are included in the DART category.

The approach taken by PG&E for its Contractor Safety risk chapter differs from this chapter; in Contractor Safety, the SIF category is segmented into "incidents sustained" and "incidents averted." The Contractor Safety chapter examines the consequences of what it terms as averted, potential, or near-miss incidents that avoided trauma or tragedy. Given that field employees are associated with 100 percent of SIF events, SPD recommends that PG&E consider segmenting the SIF outcome for employee risk as they do for contractor risk.

PG&E indicates no electric or gas reliability consequences for this risk (p. 3-16, line 24).

Controls and Mitigations

Observations:

Controls

PG&E describes 27 currently active control measures, providing for employee physical and mental screenings, in-the-field coaching mentoring/intervention, ergonomic improvements, and facilitating gradual return to work for injured employees. For the 2027 GRC period, an additional 10 measures described as mitigations in the 2023 GRC are considered to be established controls summarized in PG&E RAMP Table 3-5, on page 3-22.

PG&E presents a 2027-2030 Proposed Control and Mitigation Plan in its RAMP. The measures are organized into six control programs for presenting cost, risk reduction, and CBR data as shown in PG&E's Table 3-9, which is reproduced as Figure 7-4 below.[245]

TABLE 3-9
CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV) [(a)]			
Line No.	Control ID	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[(b)] [C]/([A]+[B])
1	EMPSI-PRGA	Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight	$5,844	$5,980	$6,119	$6,263	$16.7	–	$48.8	2.9
2	EMPSI-PRGB	CAP	3,536	3,625	3,715	3,808	10.1	–	52.5	5.2
3	EMPSI-PRGC	SIF Prevention Program and Field Oversight	13,314	13,647	13,988	14,337	38.1	–	52.5	1.4
4	EMPSI-PRGD	Employee Occupational Health and Wellness	76,921	78,370	79,102	81,064	217.8	–	52.5	0.2
5	EMPSI-PRGE	Benefit Plans, Policy, and Wellness Programs (HR)	70,049	70,097	71,850	73,646	197.2	–	52.5	0.3
6	EMPSI-PRGF	Safety Assurance and PSEMS governance	154	158	162	166	0.44	–	48.8	110.8
7		Total	$169,818	$171,876	$174,936	$179,284				

Figure 7-4. PG&E RAMP Controls Cost Data, 2027-2030, PG&E Table 3-9.

Mitigations

PG&E plans for four mitigation measures in the 2027-2030 GRC period, shown in PG&E Table 3-10, reproduced as Figure 7-5[246] below. Three of these measures are expected to transition to controls before 2030. PG&E proposes to spend $6.215 million for the four mitigations over the four-year period to reduce

245 PG&E 2024 RAMP Report, Table 3-9, p. 3-38

246 PG&E RAMP Report, Table 3-10, p 3-40.

safety risk. PG&E is already performing many risk control measures at a cost of several times the baseline risk value.

TABLE 3-10
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV) [b]				
Line No.	Mitigation ID [a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])	Factors Affecting Selection
1	EMPSI-M01B	PG&E Safety Excellence Management System (PSEMS)	$615	$1,615	$615	$615	$2.4	-	$14.1	5.8	
2	EMPSI-M016	Fit 4 You(Fit4U)Program	$477	$492	$506	$522	1.4	-	0.1	0.1	Risk Tolerance
3	EMPSI-M019	Ergonomics Program – Functional Movement Screenings	$356	$78	$80	$82	0.4	-	0.1	0.3	Risk Tolerance
4	CNTSI-M020, EMPSI-M020	SIF Capacity & Learning Model	$80	$82	-	-	0.1	-	1.4	12.1	
5		Total	$1,528	$2,267	$1,201	$1,219					

Figure 7-5. PG&E RAMP Mitigation Cost Data, 2027-2030, PG&E Table 3-10

TABLE 3-6
MITIGATIONS SUMMARY

Line No.	Mitigation Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	EMPSI-M01B – ESMS Implementation	X	Becomes EMPSI-M01B	X	Becomes control EMPSI-C25 and with be part of Safety Assurance and PSEMS governance (EMPSI-PRGF)
2	EMPSI-M06a – Office Ergonomics Program	X	Becomes EMPSI-M06a	Becomes EMPSI-C019	Becomes EMPSI-C019
3	EMPSI-M06b – Industrial Ergonomics Program	X	Becomes EMPSI-M06b	Becomes EMPSI-C019	Becomes EMPSI-C019
4	EMPSI-M06c – Industrial Athlete Program	X	Becomes EMPSI-M06c	Becomes EMPSI-C019	Becomes EMPSI-C019
5	EMPSI-M06d – Vehicle Ergonomics Program	X	Becomes EMPSI-M06d	Becomes EMPSI-C019	Becomes EMPSI-C019
6	EMPSI-M011 – On-Site Clinics	X	Becomes EMPSI-M011	Becomes EMPSI-C020	Becomes EMPSI-C020
7	EMPSI-M013 – Enhancing SafetyNet Use	X	Becomes EMPSI-M013	Becomes EMPSI-C004	Becomes EMPSI-C004
8	EMPSI-M014 – Industrial Hygiene (IH) Program Compliance Improvements	X	Becomes EMPSI-M014	Becomes EMPSI-C001b	Becomes EMPSI-C001b
9	EMPSI-M016 – Fit4U Pilot	X	Becomes EMPSI-M016	X	Transitions to EMPSI-C024 in 2028
10	EMPSI-M017 – Mobile Medics	X	Project Discontinued		
12	Ergonomics Program – Industrial Ergonomics Predictive Model (foundational)				X
13	EMPSI-M019 – Ergonomics Program – Functional Movement Screening				X
14	EMPSI-M020 – PG&E's SIF Prevention Program Capacity & Learning Model			X	Becomes control EMPSI-C026 in 2029

Figure 7-6. PG&E RAMP Mitigations Summary Table 3-6[247]

Alternatives Analysis

Observations:

PG&E presents two alternative mitigation plans. Each repeats the complete set of proposed measures, plus one incremental measure. The incremental measures are described and CBRs provided. PG&E rejected the first measure due to uncertainties with field implementation costs, while the second was rejected due to implementation uncertainties with field employees.

This presentation of alternative plans should consider the removal and/or replacement of some proposed measures with the corresponding tradeoffs of risk reduction to demonstrate that significant alternative choices were considered.

CBR Calculations

Observations:

As discussed earlier in the Mitigation section, PG&E proposes to spend $6.2 million over the four-year 2027-2030 funding cycle to support its Mitigation Plan to implement the four measures in Table 3-10. This proposed spending is relatively modest and calculates to an annual cost of $25[248] per worker, or twelve cents[249] per work hour. The program CBR for all four mitigations is 3.65,[250] although two of the measures have CBRs of 0.1, and 0.3. PG&E justifies these two based on "risk tolerance" while acknowledging that the Commission has yet to define risk tolerance. PG&E also states these two low-CBR mitigations are designed to continue driving down employee workplace injury risks,[251] though the NPV of risk reduction benefits for each is only $100,000, compared to the baseline risk of $39.1 million.

In the Controls section, PG&E proposes to spend $696 million over the four-year 2027-2030 funding cycle to support the 27 current control measures, and 10 mitigations that will transition to controls. These are combined into the six programs shown in Table 3-9 (Figure 7-3). PG&E's proposed spending outweighs the scale of the risk when compared to the baseline risk value of $39.1 million. Review of the CBR values confirms that the net present value of estimated risk reduction is less than the net present value of forecast program costs. The total program CBR of the proposed controls is less than 1.0 at 0.64.[252]

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247 PG&E 2024 RAMP Report, Table 3-6, p. 3-22.

248 Derived from the total NPV Benefits divided by total NPV program cost.

249 Derived from the mitigations cost total of $6.2 million divided by 51.45 million workhours.

250 Aggregated risk reduction benefits divided by four.

251 PG&E RAMP Report p. 3-41.

252 Derived from the cumulative NPV benefits of $307 million and the cumulative NPV program cost of $480 million. See Figure 7-3 (PG&E Table 3-9).

The six control programs have significant differences in CBRs. The EMPSI-PRGA program has a CBR of 2.9 and consists of measures necessary for compliance with health and safety regulations. Two other programs have CBRs greater than 1.0: PRGB at 5.2 and PRGF at 110. However, the two least cost-efficient programs (PRGD and PRGE) are also the most expensive, with NPV over $400 million and CBRs of 0.2 and 0.3, respectively.

Considering customer affordability concerns, the Commission should examine PG&E's 2027 GRC filing for Employee Safety programs to determine whether any less-effective programs should be funded completely. Overall, PG&E's 2027 GRC filing should more directly justify the benefits of the non-regulatory programs.

Summary of Findings

1) The difference in DART frequency data between the Bow Tie and the consequence table is not clearly explained.
2) The Contractor Safety chapter divides SIF outcomes into two categories: incidents sustained and incidents averted.
3) The proposed spending of $702 million is significantly greater than the baseline risk value of $39.1 million.
4) The absence of a consequence score for the All Other category is not explained.
5) The SIF outcome category is not divided into incidents sustained and incidents averted, as is done in the Contractor Safety chapter.
6) The Alternative Plans are very limited in scope.
7) The overall CBR is less than 1.0, indicating that the costs outweigh the benefits.

Recommended solutions to address findings and deficiencies

1) SPD recommends that the absence of values, such as the All Other category's missing consequence score, be corrected and/or addressed in a narrative explanation in the GRC application.
2) SPD recommends that PG&E consider segmenting the SIF outcome for employee risk as they do for contractor risk.
3) SPD recommends PG&E's forthcoming GRC filing should examine the cost benefits and risk tradeoffs of proposed controls and mitigations for potential savings from reduction of programs and/or measures with lower CBRs.
4) SPD recommends that PG&E consider alternative mitigation plans that provide significantly different cost options and indicate tradeoffs in risk reduction in the GRC and future RAMP filings.

8. Cybersecurity Risk Event

Risk Description

PG&E defines cybersecurity risk as a coordinated malicious attack targeting its core business functions and disrupting or damaging gas, electric, and business operations systems.[253] The scope of this risk is an event adversely affecting PG&E's Informational Technology (IT) and Operational Technology (OT) systems and infrastructure assets supporting PG&E's mission and business, as shown in Figure 8-1 below.[254] This Cybersecurity Risk Event chapter evolved from a cross-cutting model in 2020 to a standalone risk in 2021 and is currently rated as the 8th safety risk and the 4th overall risk to PG&E.[255]

PG&E's cybersecurity efforts focus on identifying, quantifying, and mitigating cybersecurity risk.[256] PG&E's program aligns the organization of its people, processes, and technologies to the National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF) core functions of Identify, Protect, Detect, and Respond, leverages the administrative and technological controls in NIST Special Publication 800-53 (NIST SP 800-53 R5), and uses NIST SP 800-37 to prioritize cybersecurity risks.[257]

Table 8-1: Risk Definition and Scope[258]

CYBERSECURITY RISK EVENT	
Definition	A coordinated malicious attack targeting PG&E's core business functions, resulting in disruption or damage of systems used for gas, electric and/or business operations.
In Scope	PG&E IT and OT systems and infrastructure assets supporting PG&E's mission and business model.
Out of Scope	Internal systems and infrastructure managed by the Nuclear functional area for Diablo Canyon Nuclear Power Plant (DCPP). IT-managed systems and devices supporting DCPP are within scope.
Data Quantification Sources	Internal PG&E Security Intelligence Operations Center (SIOC) monitored attacks and incidents, US utility industry attack statistics, Federal Intelligence reports, and cybersecurity claims data.

253 PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-2, lines 7-10.
254 PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-2 to 2-3, lines 29-33 and line 1-9, respectively.
255 PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-4, lines 6-8.
256 PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-3, lines 10-12.
257 PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-4, lines 13-16.
258 PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-3, Table 2-1.

Observations:

PG&E bases its cybersecurity practices on industry-recognized and federally-developed guidelines and standards. PG&E leverages the NIST CSF at both strategic and tactical levels to assess cybersecurity safety risks and mitigation measures. PG&E also utilizes a zero-trust security architecture[259] aligned with Standard NIST SP 800-207.[260]

Bow Tie

Line No.	Bow Tie Component	Description
1	Tranches	A logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment. The Tranches contribute to the total Exposure Point count in the Bow tie.
2	Drivers	Factor(s) that could cause one or more risks to occur (Risk driver may also be commonly referred to as "threat").
3	Exposure Points	Represents the various targets of an attack coming from one of the attack vectors (Bow Tie drivers).
4	Impact/ Consequences	The effect or outcome of an event affecting objectives, which may be expressed by terms including, although not limited to health, safety, reliability, economic and/or environmental damage.

Figure 8-1. Cybersecurity Bow Tie Constructs[261]

Observations:

The PG&E Cybersecurity Bow Tie reflects the enterprise cybersecurity risk to PG&E and is presented by four key components of (1) Tranches, (2) Drivers, (3) Exposure Points, and (4) Impact/Consequences (Figure 8-1 above). Risk factors are properly analyzed to illustrate the frequency of attacks, and the impact of risk attacks.

[259] Zero-trust security architecture is a network model in which applications, systems, and infrastructure are assumed not to be trusted and are continuously validated and authenticated.
[260] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-5, Table 2-2.
[261] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-6, Table 2-3.

Exposure

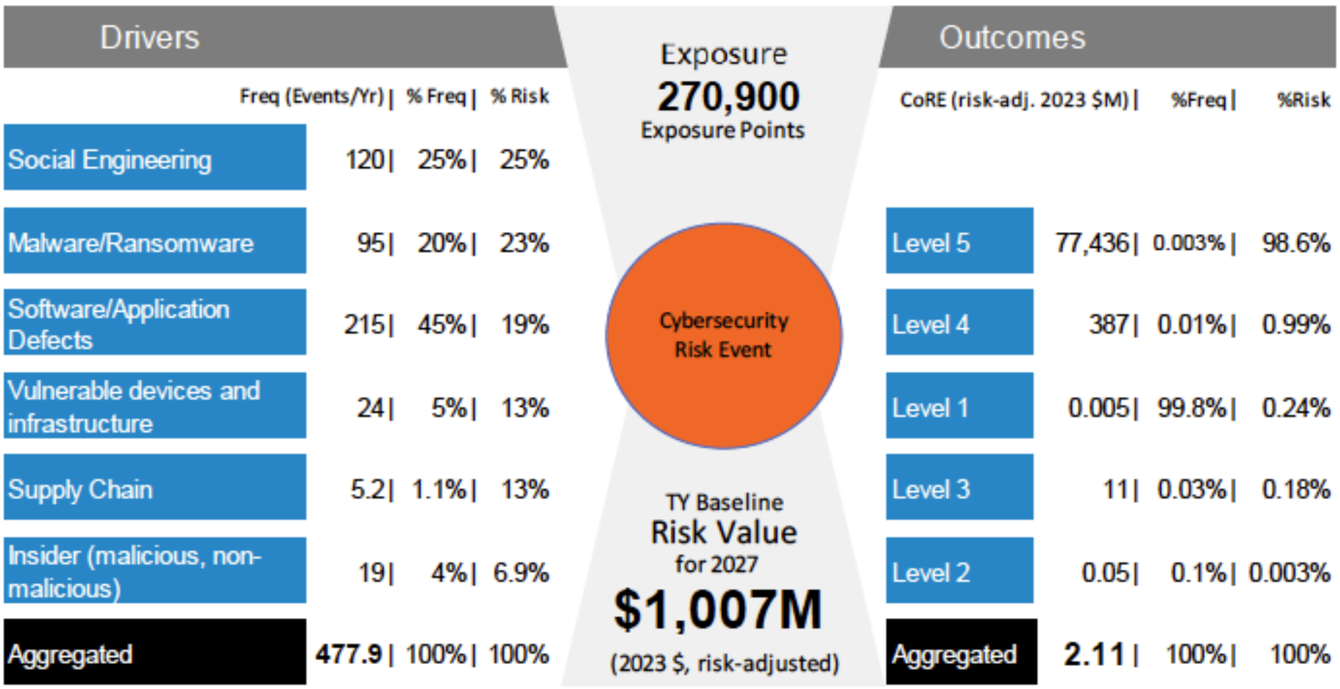

Figure 8-2: Risk Bow Tie[262]

Observations:

PG&E's exposure to cybersecurity risk is measured in Units of Exposure or Exposure Points. The total number of exposure points is calculated at 270,900 (Figure 8-2 above). Threat actors' capabilities and motivation for cyber-attacks continue to increase as new technology develops.[263]

[262] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-6, Figure 2-1.
[263] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-7, lines 11-12.

Tranches

Line No.	Tranche	Tranche Description
1	Utility Data Network (UDN)	PG&E's primary network which carries the most traffic and data and has the most users of PG&Es business systems. It is the network where PG&E conducts most of its daily business. As such, it could serve as an entry point for threat actors and UDN systems and devices are quantified to be represented as the node counts in the Bow Tie.
2	The Operational Data Network (ODN)	This network carries the traffic and data supporting the operational functions of PG&E. The ODN contains data, systems and OT technologies that are core to the generation and distribution of energy to our customers. OT systems are the primary target of nation state threat actors as an impact to the ODN could potentially cause the most disruption to PG&E and its customers. ODN systems and devices are quantified to be represented as the node counts in the Bow Tie.
3	Third Parties	Represent anyone or any entity that provides goods, services and or has access to PG&E network or data. These are vendors and business partners that for business reasons need access to our data and our network and are quantified as the third-party count in the Bow Tie.
4	People	Represent both internal employees and contractors at PG&E. They are quantified as people in the Bow Tie.
5	Software/Applications	The computer programs (COTS and custom developed) that employees and contractors use every day. Software is particularly susceptible to programing flaws, vulnerabilities and one of the vectors threat actors use to cause a cybersecurity event.

Figure 8-3: Tranche Summary[264]

Observations:

PG&E identifies five tranches, which are presented as the broad classification of the threat actors on the PG&E attack surface.[265] These tranches are: (1) Utility Data Network (UDN), (2) the Operational Data Network (ODN), (3) Third Parties, (4) People, and (5) Software/Applications (see Figure 8-3 above).

[264] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-8, Table 2-4.
[265] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-7, lines 21-24.

Risk Drivers

Observations:

PG&E identifies six classifications of risk drivers: (1) Social Engineering, (2) Malware/Ransomware, (3) Software/Application Defects, (4) Vulnerable devices and infrastructure, (5) Supply Chain, and (6) Insider Attack.[266] These risk drivers represent the attack vectors, techniques, and methods that threat actors could use to access PG&E systems. Risk drivers are adequately analyzed to illustrate related potential incidents, network software vulnerabilities, and the impact of risk attacks.[267]

Cross-cutting factors

Observations:

PG&E identifies seven cross-cutting factors of (1) Climate Change, (2) Cyber Attack, (3) EP&R, (4) Information Technology Asset Failure, (5) Physical Attack, (6) Records and Information Management (RIM), and (7) Seismic (Figure 8-4 below)[268]. The cross-cutting factor represents components of a driver or a consequence multiplier that impacts multiple cybersecurity risks.[269] PG&E clearly describes cross-cutting factors that threat actors could potentially cause data disruption and gain access to PG&E computer systems.[270]

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[266] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-9, Table 2-5.
[267] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-8, lines 2-8.
[268] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-10, Table 2-6.
[269] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-9, lines 2-4.
[270] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-9, lines 9-12.

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	No	No
2	Cyber Attack	No	No
3	EP&R	No	Yes*
4	Information Technology Asset Failure	Yes*	Yes*
5	Physical Attack	Yes*	Yes*
6	Records and Information Management (RIM)	Yes*	Yes
7	Seismic	No	No

Yes The cross-cutting factor has been quantified in the model.
Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.
No The cross-cutting factor does not meaningfully influence the baseline risk.

Figure 8-4. Cross-Cutting Factor Summary[271]

Consequences

Observations:

The consequences represent the possible outcomes or impacts of a successful cyber-attack.[272] The risk consequence impacts range from minor to catastrophic events that lead to the inability to provide gas or electricity to customers and safety consequences reliably.[273] The risk model consequences are summarized in Figure 8-5 below. The risk consequences are analyzed to specify the frequency, percentage of risk attacks, expected loss per year, and attribute risk score.[274]

[271] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-10, Table 2-6.
[272] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-10, lines 5-6.
[273] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-10, lines 5-12.
[274] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-11, Table 2-7.

Consequences

	CoRE	%Freq	%Risk	Freq	Natural Units Per Event					Monetized Levels (2023 $M) of a Consequence Per Event					CoRE (risk-adj 2023 $M/event)				
					Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial	Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial	Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial
					EF/event	EF/event	MCM/event	#cust/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event
Level 5	77,436	0.003%	98.6%	0.01	0.05	23	3,735	183,654	802	0.8	344	11,840	288	802	1.4	1,934	71,387	1,964	2,149
Level 4	387.5	0.01%	1.0%	0.03	-	-	-	-	197	-	-	-	-	197	-	-	-	-	387
Level 1	0.005	99.8%	0.2%	477.0	-	-	-	-	0.005	-	-	-	-	0	-	-	-	-	0
Level 3	11	0.03%	0.2%	0.2	-	-	-	-	8.977	-	-	-	-	8.98	-	-	-	-	10.95
Level 2	0.05	0.13%	0.003%	0.6	-	-	-	-	0.05	-	-	-	-	0.05	-	-	-	-	0.05
Aggregated	2.11	100%	100%	477.9	0.000001	0.001	0.100	4.9	0.040	0.00	0.01	0.32	0.01	0.0	0.00004	0.05	1.92	0.05	0.1

	Natural Units per Year					Expected Loss per Year (2023 $M)					Attribute Risk Score (risk-adj 2023 $M)				
	Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial	Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial	Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial
	EF/yr	EF/yr	MCM/yr	#cust/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr
Level 5	0.00	0.3	47.9	2,354.6	10	0.01	4.4	151.8	3.7	10	0.02	24.8	915.2	25.2	28
Level 4	-	-	-	-	5	-	-	-	-	5	-	-	-	-	10
Level 1	-	-	-	-	2.4	-	-	-	-	2.4	-	-	-	-	2.4
Level 3	-	-	-	-	1.50	-	-	-	-	1.5	-	-	-	-	1.8
Level 2	-	-	-	-	0.03	-	-	-	-	0.03	-	-	-	-	0.03
Aggregated	0.0006	0.29	47.89	2,354.6	19	0.01	4.41	151.80	3.7	19.28	0.02	24.79	915.24	25.19	41.76

Figure 8-5: Risk Model Consequence Summary[275]

Controls and Mitigations

Observations:

PG&E identifies the control and mitigation plans in Exhibit PG&E-7, Table 2-8: PG&E Cybersecurity Controls Summary and Exhibit PG&E-7, Table 2-9: PG&E Cybersecurity Mitigations Summary.[276]

PG&E illustrates four cybersecurity controls of (1) CYBER-C001 – Security Intelligence and Operations Center, (2) CYBER-C002 – Cybersecurity Risk and Strategy, (3) CYBER-C003 – Cybersecurity Services, and (4) CYBER-C004 – Governance and Compliance.[277] These four controls are centered on cybersecurity risk identification and management associated with its Operation and Management (O&M) expense in the 2023 GRC and 2024 RAMP. Each control has a common risk that leads to developing mitigation strategies to address the cybersecurity threats identified in the cybersecurity Bow Tie Drivers.[278] The PG&E controls provide cybersecurity detection, cybersecurity protection, event monitoring, incident response, penetration

[275] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-11, Table 2-7.
[276] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Pages 2-12 to 2-13, Tables 2-8 and 2-9.
[277] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-12 to 2-24.
[278] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-13, lines 8-13.

testing,[279] data security, and network protection services in PG&E's cybersecurity systems.[280] These controls are needed for the PG&E cybersecurity programs as the controls align to the NIST CSF classification and the NIST SP 800-37 Risk Management Framework.[281]

Mitigations: PG&E also provides forecasted 2024-2026 expenses and 2024-2026 capital cost plans.[282] The two forecast plans are summarized based on the operation and capital costs from PG&E's 2024 budget plan and are carried forward through 2030.[283] PG&E describes a summary of the 2023-2026 forecast cyber mitigations, included in (1) CYBER-M001 – Identify, (2) CYBER-M002 – Protect, and (3) CYBER-M003 – Detect. These mitigations provide technical infrastructure controls to support PG&E's network security architecture across all NIST core functions of Identify, Protect, Detect, Respond, Recover; and, to enhance PG&E's cyber landscape compliance with new regulatory cybersecurity compliance requirements from the Securities and Exchange Commission (SEC)'s cybersecurity disclosure rules.[284] This regulatory requirement requires PG&E to report cybersecurity incidents to the SEC within four business days.[285]

PG&E also provides the cost estimates, risk reduction values, Cost Benefit Ratios (CBR), and factors affecting selections for the work plan of the 2027-2030 expense shown in Table 2-13[286] and the 2027-2030 capital shown in Table 2-14.[287] These forecasts illustrate PG&E's proposed mitigations, including rationale for selecting a Protect mitigation (CYBER-M002), with a CBR less than 1.0. The CBR of CYBER-M002 Protect is calculated at 0.8, a key control and mitigation to support Identify and Detect controls.[288] When analyzing the CBRs and risk reduction values of specific mitigations, CYBER-M001 has a risk reduction value of $56.5 million and a CBR of 2.4, while CYBER-M002 has a greater risk reduction value of $113.1 million.[289]

Alternatives Analysis

Observations:

PG&E reviews the areas of highest cybersecurity risk and determines what existing NIST-based controls are in place and their effectiveness in mitigating risk associated with the cybersecurity Bow Tie.[290]

[279] Penetration testing is a security exercise that simulates a cyber-attack to test the cybersecurity capabilities and exposure vulnerabilities of an organization.
[280] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-13 to 2-14, lines 11-18 and lines 1-4, respectively.
[281] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-3, lines 10-20.
[282] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-12 to 2-29.
[283] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-16, Tables 2-10 and 2-11.
[284] Final Rule: Cybersecurity Risk Management, Strategy, Governance, and Incident Disclosure. The Securities and Exchange Commission. Regulation Identifier Number (RIN) 3235-AM89. Release Nos. 33-11216 and 34-97989. Item 1.05 of Form 8-K – *Material Cybersecurity Incident*, page 12.
[285] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-17, lines 15-20.
[286] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-24, Table 2-13.
[287] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-25, Table 2-14.
[288] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-23, lines 13-14.
[289] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-30, lines 13-16.
[290] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-29, lines 20-23.

PG&E cybersecurity process then performs the qualitative risk assessment to determine the risk associated with potential cyber-attacks. The overall Bow Tie risk assessment results are aggregated and prioritized to determine which proposed mitigations will provide the greatest risk reduction benefit.[291] These are the primary evaluation criteria for the selection of mitigations. These mitigations are then considered alternatives and saved for future analysis.[292] PG&E provides two alternative mitigations as follows:[293]

- *Alternative Plan 1: CYBER-A001 – Identify*: This plan would shift from programs with the NIST CSF classification of 'Protect' to programs with a CSF alignment of 'Identify'.[294] This strategy would shift some of the focus on the current threat landscape to evolving threats.[295] PG&E provides the cost estimates of Alternative Plan 1 (Figure 8-6 below).[296] The cost estimates are generally based on PG&E's 2024 budget plan carried forward through 2030.[297]

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[(a)]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	CYBER-A001	Identify (Alternative)	$6,521	$6,994	$7,344	$7,711	$30.9	N/A	N/A
2		Total	$6,521	$6,994	$7,344	$7,711	$30.9		

Figure 8-6: Alterative Plan 1 – Mitigation Cost Estimates, Risk Reduction, and CBR of 2027-2030[298]

- *Alternative Plan 2: CYBER-A002 – Detect:* This plan would be to increase PG&E's ability to detect an 'indicator of compromise' on the front end, and concurrently increase the ability to respond once a cyber event is detected; however, this strategy would require diverting resources from one of the other controls mitigation groups to another.[299] PG&E provides the cost estimates of Alternative Plan 2 (Figure 8-7 below).[300] The cost estimates are generally based on PG&E's 2024 budget plan carried forward through 2030.[301]

[291] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-29, lines 28-31.
[292] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter2, Page 2-29 to 2-30, line 32 and lines 1-2, respectively.
[293] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-29 to 2-33.
[294] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-30, lines 4-5.
[295] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-30, lines 7-9.
[296] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-31, Table 2-15.
[297] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-31, Table 2-15.
[298] PG&E 2024 RAMP Report, Exhibit PG&E-7. Chapter 2, Page 2-31, Table 2-15.
[299] PG&E 2024 RAMP Report, Exhibit PG&E-7. Chapter 2, Page 2-32, lines 4-8.
[300] PG&E 2024 RAMP Report, Exhibit PG&E-7. Chapter 2, Page 2-33, Table 2-16.
[301] PG&E 2024 RAMP Report, Exhibit PG&E-7. Chapter 2, Page 2-33, Table 2-16.

Line No.	Mitigation ID	Mitigation Name	Thousands of Nominal Dollars 2027	2028	2029	2030	Millions of Dollars (NPV)(a) Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	CYBER-A002	Detect (Alternative)	$33,073	$37,652	$39,718	$41,564	$164.3	N/A	N/A
2		Total	$33,073	$37,652	$39,718	$41,564	$164.3		

Figure 8-7: Alternative Plan 2 – Mitigation Cost Estimates, Risk Reduction, and CBR of 2027-2030[302]

CBR Calculations

Observations:

PG&E identifies the CBR calculation through allocated Foundational Activity program costs with the Net Present Value (NPV) using a base year of 2023. The cost estimates are based on PG&E's 2024 budget plan moving forward through the years of 2027-2030.[303] The CBR calculations show values as follows:

- CYBER-M001-Identify – CBR = 2.4
- CYBER-M002-Protect – CBR = 0.8
- CYBER-M003-Detect – CBR = 1.8

While the Protect mitigation CBR is calculated at 0.8, it is a key risk mitigation strategy to support the Identify and Detect mitigations.[304] Protect is critical to the Identify mitigation, when assessing residual risk from a Detect mitigation it can be leveraged to contain an indicator of compromise. This strategy allows PG&E to evaluate and take appropriate cybersecurity risk mitigations.[305] The CYBER-M002 has a greater risk reduction value of $113.1 million and falls into the NIST CSF functions Protect.[306]

Summary of Findings

1) PG&E's program aligns with the National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF) core functions of Identify, Protect, Detect, and Respond.
2) PG&E cybersecurity controls align to the NIST CSF classification and the NIST SP 800-37 Risk Management Framework.
3) PG&E's five identified tranches represent threat actor vectors.

[302] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-33, Table 2-16.
[303] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-22, and 2-24 to 2-25.
[304] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-23, lines 13-14.
[305] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-23, lines 15-18.
[306] PG&E 2024 RAMP Report, Exhibit PG&E-7, Chapter 2, Page 2-30, lines 15-16.

Conclusion

PG&E's Cybersecurity aligns its organization and people, processes, and technology to the NIST CSF, a commonly used risk-based cybersecurity framework. This framework provides the flexibility to establish, evolve, and adapt organizational strategies, plans, and procedures to ensure robust cybersecurity programs are in place. This is consistent with SPD's efforts to evolve to a risk-based approach to cybersecurity regulatory oversight. PG&E leveraged the NIST CSF and submitted a complete and compliant Cybersecurity Event risk evaluation.

9. Large Uncontrolled Water Release (Dam Failure)

Risk Description

Based on the Federal Energy Regulatory Commission's (FERC) hazard classification, the Large Uncontrolled Water Release (LGUWR) risk represents the potential failure of 60 high- or significant-hazard dams.

Table 9-1: Risk Definition and Scope

LARGE UNCONTROLLED WATER RELEASE (DAM FAILURE)	
Definition	Failure of a high- or significant-hazard dam, where failure could cause loss of human life and/or could cause economic loss, environmental damage, and other concerns.
In Scope	The 60 dams designated as high or significant hazard, per the FERC hazard classification system.
Out of Scope	Non-FERC-jurisdictional dams, low-hazard dams, water conveyance facilities, powerhouses, and other hydroelectric assets. Although low-hazard dams are not included in LGUWR, PG&E inspects and maintains these dams.
Data Quantification Sources	PG&E engineering evaluations and studies (such as dam stability analyses, seismic hazard analyses, flood hazard analyses, risk assessments, dam breach analyses), PG&E Emergency Action Plans, and ICOLD (2019) database on dam failures.

Observations:

In Informal Comments, CalAdvocates has noted concern over drownings occurring in PG&E's water conveyance system and requests PG&E justify why this risk event has not been included in its RAMP submission.[307] In 2018, a 10-year-old fell into a PG&E canal in Meadow Vista and drowned.[308] Because these events are unrelated to a LGUWR risk event, SPD recommends that PG&E consider modeling the safety and financial consequences as well as the likelihood of citizens being injured or drowning after falling into PG&E's water conveyance system and any mitigations to reduce the likelihood or consequence of such

[307] The Public Advocates Office Corrected Informal Comments on the Application of Pacific Gas and Electric Company (U39M) to Submit its 2024 Risk Assessment and Mitigation Phase (RAMP) Report at 11.

[308] Community Mourns 10-Year-Old Found Dead In PG&E Canal, CBS13, https://www.cbsnews.com/sacramento/news/community-mourns-10-year-old-found-dead-in-pge-canal/

a risk event in its 2028 RAMP filing. This is a unique risk event, and how it ranks against other enterprise risks listed in PG&E's 2028 RAMP filing should be determined.

Bow Tie

The drivers integrated in PG&E's bow tie model are associated with representations of potential failure modes (PFM), an industry-accepted way of framing and assessing dam safety.[309] These PFMs describe the sequence of events and likelihood of failure that would result in two outcomes listed by PG&E as an uncontrolled release in an unpopulated area (Outcome 1) or an uncontrolled release in a populated area (Outcome 2). In its 2024 RAMP filing, PG&E has significantly updated the PFMs for the LGUWR risk. PG&E notes that only 4 out of 60 dams have fully modeled PFMs based on PG&E's collaboration with FERC's Semi-Quantitative Risk Assessment (SQRA) program.[310] Rather than dependent on a resource-intensive, fully quantitative risk analysis, SQRA utilizes a risk matrix approach to assign likelihood and consequence categories to PFMs based on existing data and estimates.[311] PG&E estimates that it will take 10-15 years to complete the risk assessments for the other 56 dams.

Observations:

There is a confusing relationship between Outcome 1/Outcome 2 and a list of eight other disaggregated outcomes. Please see the detailed analysis of this issue in the Consequences section along with SPD's recommendations for PG&E.

It was not clear in the RAMP filing why PG&E selected the four dams for collaboration with FERC's SQRA program. In response to a data request, PG&E confirmed three dams (Spaulding Nos. 1, 2 and 3 dams) were due for a FERC dam safety inspection in 2023, thus they were selected to participate in the SQRA program. The fourth dam (Pit 3 dam) was a special case to better understand whether a newly discovered fault had the potential to extend underneath the dam.[312] PG&E also noted that it expects 5-7 dams per year to complete the SQRA for the remaining dams[313].

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309 For more on Potential Failure Mode and Potential Failure Mode Analysis, see: FERC, Engineering Guidelines for the Evaluation of Hydropower Projects, Chapter 14, https://www.ferc.gov/industries-data/hydropower/dam-safety-and-inspections/eng-guidelines .

310 The four dams include Spaulding Nos. 1, 2 and 3 as well as the Pit 3 dam. For more on the SQRA program, see also Boyer and Gross, Some Observations from FERC Risk Analysis Pilot Studies, USSD 2022 Annual Conference, https://cms.ferc.gov/media/some-observations-ferc-risk-analysis-pilot-projects

311 For details on SQRA see Bureau of Reclamation and U.S. Army Corps of Engineers Best Practices in Dam and Levee Safety Risk Analysis, Chapter A-04 Semi-Quantitative Risk Analysis, Denver, Colorado, July 2019 https://www.usbr.gov/damsafety/risk/BestPractices/Chapters/A4-Semi-QuantitativeRiskAnalysis.pdf.

312 PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q001, 01.a at 1-2 (July 22 2024).

313 PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q001, 01.f.i at 2 (July 22 2024).

PG&E provided little to no description of the significant update they made to the PFMs that directly impact the calculation of LoRE in this chapter. A data request asked PG&E to provide a list of the PFMs used in the 2024 RAMP along with each PFMs potential impact on the likelihood calculation for the PFM's associated driver.[314] At present, 31 of the dams still only have one PFM per driver, while dams that have participated in the SQRA have many PFMs for the Flood, Seismic and Normal drivers.[315] This is a good indication that had SQRA been applied, additional PFMs would have been identified for each of these 31 dams. Given this potentially significant safety gap, SPD recommends that the updated list of PFMs be included as part of PG&E's testimony in its 2027 GRC. It is in PG&E's best interest to provide this added transparency on the cutting-edge approaches it is taking to analyze the LGUWR risk. This updated list will also let ratepayers and decision-makers know that the company is working with FERC to make even more accurate decisions regarding the safety of dam assets.

In the recent RDF Proceeding D.24-05-064, the Commission required the utilities by December 6, 2024 to submit a report on improvements to data needed for properly analyzing its risks and a timeline for making those improvements.[316] SPD expects PG&E to include a deeper description of its efforts to improve PFMs in collaboration with FERC in that report.

Tranches

A list of the details associated with the 60 dams can be found in the GEN-LGUWR-06_Tranche Selection workpaper.

Observations:

Although previous RAMP evaluations have not critically reflected on PG&E assigning one tranche for each of its high- or significant-hazard dams, recent review and discussion of tranches in the RDF Proceeding has led SPD to re-evaluate its position since PG&E's 2020 RAMP. Designating a tranche for each dam makes it challenging to assess the appropriateness of prioritizing investments in mitigations at some dams and not others. Designing tranches at the asset level also makes it difficult to understand the impacts of changes PG&E has made to its risk model. Moreover, this approach does not meet the definition of a tranche in the Risk-based Decision-making Framework:

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314 For details see PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q002, 02.a and DR RAMP-2024_DR_SPD_005-Q003, 03.a as well as spreadsheets Q2_PFM List and Q3_PFMxDam within RAMP-2024_DR_SPD_005-Atch01.xlsx

315 Spaulding No. 1 has 26 PFMs, Pit 3 has 18, Spaulding No. 2 has 16 and Spaulding No. 3 has 9. There are some non-SQRA dams such as Belden Forebay (13) and Lake Almanor (9) with multiple PFMs per driver, but most only have 6 or 7 total. There is no PFM for the Normal driver for the Balch Diversion, Wishon Auxiliary No. 1, Rock Creek (Drum) Arch, and Grizzly Forebay, all four of which are concrete dams, thus they only have 3 PFMs eaChapter

316 D.24-05-064 at OP4 and at 27-28.

> Tranche: a logical disaggregation of a group of assets (physical or human) or systems into <u>subgroups with like characteristics</u> for purposes of risk assessment.[317]

The subgroup must be composed of more than one asset to meet the definition of a tranche, which requires the assets within the subgroup to share similar characteristics. If the group of assets is disaggregated to the individual asset scale, then there will be no additional assets within the subgroup *with like characteristics*.

SPD designed LoRE and CoRE tranches using the 33rd percentile to group together homogenous LoRE and CoRE scores of the 60 dams.[318] This method creates three percentile groupings of LoRE and three percentile groupings of CoRE, which can be used to establish nine LoRE and CoRE tranches[319]. According to the analysis conducted by SPD, nine LoRE and CoRE tranches is the recommended approach for the sixty dams assessed within PG&E's LGUWR risk chapter. SPD explored the changes to PG&E's risk modeling between the 2023 GRC and 2024 RAMP filings by using the TYBaseline2023_Attribute spreadsheet in the PGEN-LGUWR-02_Bow tie 2023 GRC.xlsm workpaper and the TYBaseline2027_Attribute spreadsheet in the GEN-LGUWR-02_Bow Tie.xlsm workpaper. SPD created Table 9-2 and Table 9-3 based on risk ranking of the dams and collecting the dams into nine LoRE and CoRE tranches:

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[317] D.22-12-027, Appendix A at A-5, emphasis added

[318] This would mean that portions of a risk with the highest 33 percent of LoRE and highest 33 percent of CoRE would be grouped within a tranche. Another tranche would be composed of portions of risk with the highest 33 percent of LoRE and the second highest 33 percent of CoRE, and so on. For this analysis

[319] For details on the LoRE and CoRE method for creating tranches see D.24-05-064 at 26.

Table 9-2: Comparison of Top Ten Riskiest Dams

Rank	Top Ten Riskiest Dams in 2023	Top Ten Riskiest Dams in 2027[320]
1	Spaulding No. 2	Pit 3
2	Spaulding No. 3	Pit 5 Open Conduit
3	Belden Forebay	Fordyce
4	Fordyce	Spaulding No. 1
5	Spaulding No. 1	Belden Forebay
6	Salt Springs	Lake Almanor
7	McCloud	Rock Creek (Feather)
8	Bucks Lake (Storage)	Salt Springs
9	Pit 5 Open Conduit	Pit 4
10	Pit 3	Iron Canyon

Table 9-3: Comparison of Nine LoRE and CoRE Tranches in 2023 GRC and 2024 RAMP Filings

Tranche	Tranche Structure	Number of Dams 2023	Number of Dams 2027	Name of Dams 2023[321]	Name of Dams 2027
1	LoRE 1 CoRE 1	4	7	Spaulding No. 2 Spaulding No. 3 Fordyce Salt Springs	Pit 3 Pit 5 Open Conduit Fordyce Rock Creek (Feather) Salt Springs Pit 4 Pit 6
2	LoRE 1 CoRE 2	6	7	Belden Forebay McCloud Bucks Lake (Storage) Pit 5 Open Conduit Pit 3 Rock Creek (Feather)	Spaulding No. 1 Belden Forebay Lake Almanor Pit 7 Spaulding No. 2 Bucks, Lower (Diversion) Peak, Upper

[320] This ranking is identical to PG&E's 2024 RAMP filing, Table 1-3 at 1-29.

[321] Within each Tranche, the dams are listed from highest to lowest amount of total risk.

Tranche	Tranche Structure	Number of Dams 2023	Number of Dams 2027	Name of Dams 2023[321]	Name of Dams 2027
3	LoRE 1 CoRE 2	11	7	Round Valley Tiger Creek Afterbay Cresta Lyons Pit 6 Balch Diversion Pit 7 Philbrook Tiger Creek Regulator Rucker Blue, Upper (Moke)	Butt Valley Round Valley Macumber Kidd Lake Auxiliary Halsey Forebay No. 1 Cape Horn Wise Forebay
4	LoRE 2 CoRE 1	7	7	Spaulding No. 1 Scott Kidd Lake Halsey Forebay No. 1 Chili Bar Butt Valley Peak, Upper	Iron Canyon Spaulding No. 3 Bear, Upper Grizzly Forebay Bear, Lower No. 1 Crane Valley Cresta
5	LoRE 2 CoRE 2	7	5	Macumber Bear, Lower No. 1 Bear, Lower No. 2 Rock Creek (Drum) South Kidd Lake Auxilary Pit 4 Wise Forebay	Kidd Lake McCloud Scott Tabeaud Lake Valley
6	LoRE 2 CoRE 3	4	7	Balch Afterbay Cape Horn Pit 7 Afterbay Rock Creek (Drum) North	Balch Diversion Tiger Creek Regulator Lake Valley Auxiliary Philbrook Blue, Upper (Moke) North Battle Creek Rucker
7	LoRE 3 CoRE 1	10	7	Strawberry Lake Almanor Halsey Afterbay Rock Creek (Drum) Arch Tabeaud Crane Valley Halsey Forebay No. 2 Courtright North Battle Creek Pit 1	Relief Bucks Lake (Storage) Bear, Lower No. 2 Tiger Creek Afterbay Pit 1 Wishon Courtright
8	LoRE 3 CoRE 2	6	7	Bear, Upper Lake Valley Bucks, Lower (Diversion) Relief Iron Canyon Wishon	Strawberry Wishon Auxiliary No. 1 Rock Creek (Drum) South Halsey Forebay No. 2 Rock Creek (Drum) Arch Halsey Afterbay

Tranche	Tranche Structure	Number of Dams 2023	Number of Dams 2027	Name of Dams 2023[321]	Name of Dams 2027
					Balch Afterbay
9	LoRE 3 CoRE 3	5	6	Lake Valley Auxiliary Manzanita Blue Lake (Drum) Drum Forebay Grizzly Forebay	Drum Forebay Lyons Pit 7 Afterbay Rock Creek (Drum) North Blue Lake (Drum) Manzanita

Table 9-3 provides insight into how the new PFMs discussed above are distributed across the homogenous risk profiles. Dam names that are highlighted in dark blue participated in FERC's SQRA pilot and each dam has more than nine PFMs across the four drivers.[322] PG&E has updated the risk model for dam names highlighted in red since the 2023 GRC filing to include five or more PFMs per dam. The unhighlighted dams still have fewer than five PFMs. For PG&E's LGUWR risk model, there is currently an average of 5.75 PFMs per dam, but the distribution of new PFMs is significantly skewed towards six dams.[323] With the exception of Tranches 8 and 9 in the 2024 RAMP, new PFMs have been introduced into the analysis of dams in all the other tranches. It is unclear how the risk model and the homogenous risk profiles will change once PG&E applies SQRA and/or introduces new PFMs to all its dams. This piecemeal approach to updating the LGUWR risk model makes it difficult to know if PG&E is properly prioritizing its mitigations discussed below.

These tables demonstrate why breaking up risk into appropriately granular tranches is so important to understand the data at a high level. The Iron Canyon dam provides an illustrative example. Using SPD's suggested 9-tranche LoRE and CoRE groupings, there are 21 dams in the top three tranches in the 2024 RAMP, as the Table 9-3 above shows. Since Iron Canyon is in Tranche 4, the 21 dams in Tranches 1 to 3 have a higher risk profile than Iron Canyon. This is significantly different from the 10th highest risk ranking that PG&E gave it in the 2024 RAMP filing narrative. This highlights why SPD's grouping of LoRE and CoRE into nine tranches is more logical than PG&E's methodology of treating each dam as a tranche. This raises questions: What did the risk model results for Iron Canyon look like in the previous GRC cycle? Did PG&E conduct any mitigations on Iron Canyon in the previous GRC cycle? Table 9-3 demonstrates that

[322] The Spaulding No.1 dam already has completed 26 PFMs.

[323] Spaulding Nos. 1-3, Pit 3, Belden Forebay and Lake Almanor dams all have more than nine PFMs. For comparison, SCE has an average of 8.74 PFMs per dam and only one of its dams participated in the FERC SQRA Pilot. See SCE 2022 RAMP Application, Chapter 12, at 13

even in the very recent 2023 GRC, the risk model placed Iron Canyon in the 8th tranche.[324] There is no explanation in the 2024 RAMP filing why Iron Canyon is listed as 10th in the risk rankings. SPD's review of the seismic and flood driver workpapers also revealed no explanation for the fact that an improvement in data quality led to a rise in the frequency of this dam potentially failing due to an earthquake or flood. The risk model also does not demonstrate that Iron Canyon has a significant number of fatalities or damaged buildings during an In Flow Design (IDF) and Fair Weather (FW) event .[325] Instead, the SPD analysis of workpapers discovered that the primary reason for the rise in risk ranking for Iron Canyon is foregone revenue in the event of a breach at Iron Canyon. Understanding why Foregone Revenue has been modeled at such a higher degree for Iron Canyon in the 2024 RAMP compared to the 2023 GRC would be helpful. SPD recommends that PG&E explain this in its 2027 GRC filing.

Moreover, these kinds of explanations are necessary when such changes result in dramatic increases in risk levels and when a sudden drop in risk level occurs. The McCloud dam is an important example to illustrate this point. Within the 2023 GRC filing, McCloud was ranked 7th according to risk and was listed at the top of Tranche 2 in Table 9-3. The 2023 GRC decision also approved a significant upgrade to the McCloud spillway. However, the McCloud spillway is a long-term project, and the considerable capital expenditures for that project extend into the 2024 RAMP filing and the 2027 GRC filing. Despite having a high-risk score in the 2023 GRC filing, PG&E's new risk model in the 2024 RAMP ranked McCloud 30th in risk and at the top of Tranche 5. Since the McCloud spillway upgrade will not be completed until 2030, this spillway mitigation cannot explain the sudden drop in relative risk between the two filings. Within the 2024 Flood Risk spreadsheet in the GEN-LGUWR-10_CONFIDENTIAL_Flood Risk.xlsm workpaper, we do learn that flood frequency analysis was calculated using SQRA and overtopping risk was developed by "Gannet Fleming in June 2022," which is not explained in the workpaper. For this workpaper, both of these responses are unique to the McCloud dam. None of these changes to the risk model are explained in the workpaper's ReadMe worksheet. Oddly, the acronym SQRA is used throughout the LGUWR narrative and workpapers to describe PG&E's engagement with FERC SQRA methods, but McCloud was not listed as participating in that program. Thus, it appears that a unique approach was taken to assess this dam without explanation. SPD recommends that PG&E provide a more detailed explanation for why the McCloud dam's risk score relative to the other dams dropped considerably in the 2024 RAMP filing.

SPD repeats the point: establishing one tranche per dam makes it extremely difficult to understand the changes to the LGUWR risk model and how PG&E intends to prioritize the mitigation of the LGUWR risk. The issue of prioritization will be addressed again in the CBR section below. Utilizing the LoRE and CoRE approach to establishing tranches brings additional clarity and organization to PG&E's LGUWR risk event risk modeling. This approach will guide PG&E in providing greater transparency in how its risk models are designed and encourage PG&E to take better care when developing its narrative of changes to its risk models. At this time, SPD is not asking PG&E to design mitigations based strictly on the LoRE and

324 Additionally, the 2023 GRC risk model also listed Iron Canyon in the 48th position of risk rankings.

325 For details on the difference between IDF and FW, see the Consequence section below.

CoRE approach to establishing tranches. For additional context and observations on PG&E's mitigation of the LGUWR risk, please see below.

Risk Drivers

D1-Flood

For the flood driver, four dams have a more complete set of PFMs, nine other dams have relatively complete PFMs, and 47 dams only include consideration of extreme flood-overtopping PFMs.

The annual likelihood of LGUWR caused by flooding was computed by multiplying the annual probability exceedance of the critical flood by the probability of dam failure given the occurrence of the critical flood loads. PG&E used different criteria for different dam types to assess the flood driver.[326]

D2-Seismic

As with the 2020 RAMP, the majority of PG&E's dams (N=56) only consider full global instability PFMs for seismic loading. The risk analysis of the four dams that participated in the FERC program described above, has now been expanded to include any PFMs that could result in uncontrolled release from partial to full dam breach and component failures. For the 56 dams, the annual likelihood of failure caused by seismic load was computed by multiplying the annual probability exceedance of the seismic load with the probability of dam failure given the occurrence of the seismic loads.[327]

D3-Failure under Normal Operation Conditions

In the 2024 RAMP, the definition of failure under normal operation conditions includes not only internal erosion PFMs at earthfill and rockfill-embankment dams, but also uncontrolled releases from day-to-day operations of a variety of dam types due to mechanical failures of spillway gates or low-level outlets (LLO) and internal erosion of foundation material beneath the dams or in the abutments. In workpaper GEN-LGUWR-07_Inputs_to_Bowtie.xlsx, approximately 26 new PFMs[328] can be found with varying likelihood of failure.

D4-Physical Attack (See observations below)

Observations:

D1-Flood

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[326] The details for each dam's probability of failure due to the flood driver are found in GEN-LGUWR-10_CONFIDENTIAL_Flood Risk.xlsx.

[327] The details for each dam's probability of failure due to the seismic driver are found in GEN-LGUWR-11_CONFIDENTIAL_Seismic Risk.xlsx.

[328] There are 30, but four of those listed are also related to internal erosion

Tracing down how PG&E assigned probabilities of dam failure for the concrete gravity and arch dams is not straightforward. A footnote in the RAMP narrative referencing the 2024 Flood Risk spreadsheet in the GEN-LGUWR-10 workpaper would have been helpful. In the future, PG&E should provide sufficient citations to easily locate the source of the information discussed in the narrative. Likewise, a significant number of new flood-related PFMs were developed for the 2024 RAMP, but PG&E provided minimal details in either the narrative or workpapers.

Additionally, some assumptions within the driver dataset for floods require greater clarity. For example, one variable, referred to as the "likelihood factor" in the 2020 RAMP filing, was renamed as "probability of failure" in the 2024 RAMP filing.[329] In a data request response, PG&E described the probability of failure variable as "the conditional probability of dam failure given the initiating event (i.e., initiating flood)", although PG&E did not explain why it changed the name.[330]

More importantly, between the 2020 and 2024 filings, 13 dams witnessed significant increases or decreases in the value of the "probability of failure" variable. For instance, Balch Afterbay Dam was assigned a 0.5 probability of failure at the critical flood level. However, in the 2020 RAMP the same dam was assigned a 0.01 probability of failure at the critical flood level. PG&E explained that this change was based on the judgment that the initiating flood at or above the top of aeration piers at the dam could induce pulsating loads that reduce the dam's safety factor.[331] This is the justification for the value selected for the 2024 RAMP, but it does not clearly explain why PG&E assigned a different value in the 2020 RAMP. In contrast, this change between the filings was reversed for some dams, decreasing the 2024 RAMP value. For instance, the Lyons dam was assigned a 0.1 probability of failure in the 2024 RAMP but was assigned a 0.5 probability of failure in the 2020 RAMP. In this case, PG&E stated in response to a data request that the probability of dam failure decreased because the abutment was judged to have medium potential for erosion when the flood overtops the dam.[332] Again, this data request response was simply the justification for the value selected for the 2024 RAMP, but it does not explain why PG&E made the change between the filings. SPD recommends that PG&E shouldproperly explain why it made the 13 changes between the two filings in its 2027 GRC filing.

The flood driver constituted approximately 86 percent of the risk drivers for LGUWR in the 2020 RAMP but only 51 percent in the 2024 RAMP. According to the 2020 RAMP, an incident leading to uncontrolled release was estimated to occur once every 76 years, whereas in the 2024 RAMP this was estimated to occur once every 50 years or once every 85 years if only the outcome of uncontrolled release in populated areas was considered.

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[329] Equally confusing, PG&E named the column that provides a justification for this variable as "likelihood of failure justification". SPD asks PG&E to pay greater attention to naming conventions and to organize its workpaper in a professional manner.

[330] PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q004, 04, p. 2, dated July 22 2024

[331] PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q004, 04.a, p. 2, dated July 22 2024

[332] DR RAMP-2024_DR_SPD_005-Q004, 04.d, p. 2, dated July 22 2024

D2-Seismic

It was unclear from the 2024 RAMP filing how the likelihood of failure for the seismic driver was calculated for the four dams that participated in the FERC SQRA. Confusingly, within the seismic driver workpaper, PG&E stated that only one dam has undergone a SQRA, while three dams have undergone a "Comprehensive Assessment."[333] Since this latter form of (risk) assessment was not described in the RAMP narrative, it is unclear whether Comprehensive Assessment is a more thorough or more rigorous risk assessment than SQRA, or how these two assessment approaches differ. PG&E provided some additional information on how it intends to conduct these assessments for all 60 of its FERC-classified dams over the next 10-15 years in data requests, but it did not explain the difference between a Comprehensive Assessment and the SQRA.[334]

PG&E noted that it should ideally use the critical seismic load to estimate the likelihood of failure. Currently, seismic analyses only include ground motion for the deterministic design earthquakes, which are typically smaller than the critical load. In its data update report, PG&E should state when seismic analyses will include an estimation using critical seismic load.[335]

The shift in risk modeling of the seismic driver from the 2020 RAMP to the 2024 RAMP is significant but PG&E's justification for doing so is unclear. The seismic driver accounted for only 6 percent of the risk in the 2020 RAMP but is now 37 percent in the 2024 RAMP. The seismic driver in the 2020 RAMP could result in a dam failure once every 714 years, but in the 2024 RAMP, PG&E estimated that the seismic driver could result in an LGUWR event frequency of once every 69 years, which is reduced to once every 95 years if only the outcome of an uncontrolled release in populated areas is considered. SPD recommends that PG&E explain in detail what exactly changed with its seismic driver that could result in such a significant shift in the modeling in its 2027 GRC filing.

D3- Failure under Normal Operation Conditions

Despite adding a significant number of new PFMs to this driver (see discussion in the Bow Tie section above), the information PG&E provides in the RAMP narrative about new PFMs for the Normal driver is sparse. Moreover, at no point does the narrative attempt to describe how the likelihood of failure was estimated for these new PFMs. There are also no citations explaining to a reader that they could find some limited information about these new PFMs within the Ref_PFMs spreadsheet in the GEN-LGUWR-07_Inputs_to_Bowtie.xlsx workpaper. Moreover, there does not appear to be any rationale explaining how PG&E arrived at the likelihood of failure calculations located in this spreadsheet. The Readme worksheet states that PFMs were taken directly from risk assessments for dams that had undergone a complete FERC

[333] See the 2024 Seismic Risk spreadsheet Column Z in the GEN-LGUWR-11_CONFIDENTIAL_Seismic Risk.xlsx workpaper.

[334] For details see PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q002, 02.a and DR RAMP-2024_DR_SPD_005-Q003, 03.a as well as spreadsheets Q2_PFM List and Q3_PFMxDam within RAMP-2024_DR_SPD_005-Atch01.xlsx

[335] Due December 6, 2024, see D.24-05-064 at OP4 and pp. 27-28.

risk assessment. However, some of these dams with unique PFMs (i.e. Belden Forebay, Butt Valley, and North Battle Creek) were never associated with a FERC risk assessment elsewhere in PG&E's narrative or workpapers.

PG&E needs to better provide links and citations to the databases it uses to inform its risk assessments, such as the International Commission on Large Dams (ICOLD) database. Unfortunately, throughout the evaluation period and as of this writing, the website for this database is inaccessible.[336] More importantly, it should be noted that ICOLD is proprietary and requires an expensive subscription to access it. SPD recommends that PG&E explore other open-source databases, such as Global Dam Watch[337] or the Global Dam Tracker,[338] which are now the industry standard and have been well-discussed in scientific literature.[339]

In the 2020 RAMP, this driver was called Internal Erosion, amounted to only 5 percent of the LGUWR driver risk, and would potentially generate an incident once every 1667 years. In the 2024 RAMP, PG&E estimated the Normal driver to constitute 12 percent of the risk for LGUWR and would result in an event once every 176 years or once in 737 years if only the outcome of an uncontrolled release in populated areas is considered. Similar to the seismic driver above, there is no attempt by PG&E to explain the dramatic shift in the Normal driver between the 2020 and 2024 RAMPs. SPD recommends that PG&E shouldexplain in detail in its 2027 GRC filing what exactly changed between the 2020 RAMP and 2024 RAMP filings with its Normal driver that could result in such a significant shift in the modeling.

D4-Physical Attack

The data used to calculate the physical attack frequency and the probability of dam failure[340] should be based on a more robust review of such attacks. PG&E did not discuss the PFM associated with the physical attack driver in the 2024 RAMP filing, but in a data request PG&E noted that a generic PFM was developed during the 2020 RAMP and it remains unchanged.[341]

Although during a recent 11-year period there has only been one attack in the United States against a dam, which was unsuccessful, PG&E estimates that there is a 5.9-in-a-million chance of such an attack occurring again and there is a 3.8 percent chance that such an attack will result in a LGUWR event.[342] Potential

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336 https://www.icold-cigb.org/

337 https://www.globaldamwatChapterorg/database

338 https://www.energypolicy.columbia.edu/publications/power-river-introducing-global-dam-tracker-gdat/

339 Zhang, Alice Tianbo, and Vincent Xinyi Gu. "Global Dam Tracker: A database of more than 35,000 dams with location, catchment, and attribute information." *Scientific data* 10, no. 1 (2023): 111. https://www.nature.com/articles/s41597-023-02008-2

340 With 25 global attacks on a dam, it is assumed that the next one will be successful, so 1/26 = 3.8 percent chance of failure

341 PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q002, 02.b at 2, July 22 2024

342 The details of these calculations are found in the GEN-LGUWR-13_CONFIDENTIAL_Physical Attack.xlsx workpaper.

physical attacks accounted for driving 0.1 percent of the LGUWR risk and would only happen once every 73,700 years, a frequency similar to that used in the 2020 RAMP.

In PG&E's GEN-LGUWR-02_Bow Tie workpaper, it is apparent that the physical attack driver is only relevant to the Fair Weather full dam breach outcome (see Consequences section below). PG&E does not explain why only the full dam breach outcome is considered. SPD recommends that PG&E should explain why it does not consider the potential for an attack to result in partial dam breaches in its 2027 GRC filing. In fact, causing a full dam breach with a physical attack is extremely difficult. It is far more likely that a physical attack on a dam would result in a partial breach rather than a full breach. Although a formal investigation report has yet to be published, the collapse of the Kakhovka Dam appears to have required explosives to have been placed from within the dam.[343] Historical evidence, such as the destruction of the Huayuankou dike along the Yellow River that was perpetrated by the Nationalist Chinese army in 1938, also points towards the purposeful placing of explosives by entities in control of the infrastructure to result in a full breach.[344] Seeing that PG&E describes the physical attack as a covert terrorist attack, it seems unlikely that a full breach of a dam due to a physical attack would be realistically feasible.

Cross-cutting factors

All seven cross-cutting factors impact either the likelihood or consequence of LGUWR, but in two cases that impact was not quantified. Table 9-4 clarifies how PG&E views the impact of cross-cutting factors on LGUWR:

343 https://www.nytimes.com/interactive/2023/06/16/world/europe/ukraine-kakhovka-dam-collapse.html

344 Dutch, Steven I. "The largest act of environmental warfare in history." *Environmental & Engineering Geoscience* 15, no. 4 (2009): 287-297. Muscolino, Micah S. (2014). *The Ecology of War in China: Henan Province, the Yellow River, and Beyond, 1938–1950*. Cambridge University Press.

Table 9-4: Relationship between Cross-cutting Factors and the LGUWR Risk Event

Cross-cutting factor	Impacts Likelihood	Impacts Consequence	How it is addressed in model?	LGUWR Workpapers	Cross-cutting Workpapers
Climate Change	Not quantified	No impact	N/A	N/A	N/A
Cyber Attack	Not quantified	No impact	N/A	N/A	N/A
EP&R	No impact	Quantified	Incorporated into computation of fatalities	GEN-LGUWR-14_CONFIDENTIAL_LifeLoss_Economic_Consequences.xlsx	None made available
ITAF	Quantified	No impact	Frequency Multiplier	GEN-LGUWR-07_Inputs_to_Bowtie.xlsx: Readme and Ref_Aggregated_Risk_with_CC Spreadsheets;	CC-ITAFL-1_LGUWR Mapping and Freq calc.xlsx
Physical Attack	Quantified	No impact	Explicit Driver	GEN-LGUWR-13_CONFIDENTIAL_Physical Attack.xlsx	CC-PHYSA-5_TY Baseline Risk Data.xlsx
RIM	No impact	Quantified			
Seismic	Quantified	No impact	Explicit Driver	GEN-LGUWR-11_CONFIDENTIAL_Seismic Risk.xlsx	None relevant for LGUWR

Observations:

CC1 – Climate Change

Overall, PG&E does not expect climate change to have a significant impact during the near term (2024-2030) for LGUWR and has not attempted to model those impacts in this RAMP filing. PG&E explained that the long-term average drier climate across PG&E's territory is not expected to impact LGUWR, but due to the uncertainty of climate models, there is a scenario where extreme wet storms could potentially increase the likelihood of dam overtopping by 2050. While reviewing the relationship of LGUWR to the Climate Adaptation Vulnerability Assessment (CAVA) results, PG&E notes that the adaptive capacity of PG&E's hydro generation assets to future climate hazards was a key factor in determining its climate risk rankings. While this may be true, it is not explicitly or quantitatively demonstrated in the 2024 RAMP filing. SPD recommends that PG&E clarify this relationship in its upcoming Climate Pilot White Paper, due no later than September 15, 2025, as ordered in D.24-05-064.

CC2 – Cyber Attack

In this RAMP filing, PG&E has not attempted to model the increased likelihood of a LGUWR risk event due to a cyberattack. In future RAMP and GRC filings, it would be important for PG&E to distinguish how distinct the cross-cutting impacts from a cyber attack versus the Information Technology Asset Failure (ITAF) would be. On the surface, it is not clear that the impacts of these two cross-cutting factors would be that different when it comes to the LGUWR. Ultimately, both would increase the likelihood, and possibly the consequence, of a catastrophic LGUWR event, but it is not clear that a cyber attack would result in a higher increase to the likelihood and/or consequence than ITAF, and vice versa. If PG&E does see a distinction, it should describe that distinction in detail for decision-makers in a future Application to the Commission.

CC3 – Emergency Preparedness and Response (EP&R)

PG&E issues emergency warnings and activates an EP&R team to support evacuations if there is an imminent dam failure that would impact public safety. For LGUWR, the issuance of emergency warning and response was incorporated into the computation for fatalities. However, that quantification is not explicit in the workpapers. The primary workpaper supporting the calculation of fatalities is GEN-LGUWR-14_CONFIDENTIAL_LifeLoss_Economic_Consequences.xlsx, but it contains no discussion of EP&R or how it was integrated into the Dekay-McClelland method or RCEM and LifeSim (see Consequences below for details).[345] In a data request response, PG&E explained that the warning time parameter within the Dekay-McClelland method was equated to the time of arrival for the front wave from the dam breach.[346] While PG&E does provide data related to the front wave in its workpaper, there was no explanation that this data was used to represent the impact of EP&R on the calculation of safety consequence. According to PG&E, the logic is that there would be "more time to warn and evacuate people who are located farther away than those immediately downstream of the dam."[347] While this may be true, this correlation of additional warning time for people located farther away is only a loose proxy for EP&R. This correlation should be explained more clearly, and if possible, it should be quantified. SPD recommends that PG&E should explicitly quantify EP&R within workpapers and the narrative of the application in the 2027 GRC

[345] DeKay, Michael L., and Gary H. McClelland. "Predicting loss of life in cases of dam failure and flash flood." *Risk analysis* 13, no. 2 (1993): 193-205. https://www.researchgate.net/publication/230288562_Predicting_Loss_of_Life_in_Cases_of_Dam_Failure_and_Flash_Flood/link/5a743c100f7e9b20d490fcdf/download?_tp=eyJjb250ZXh0Ijp7ImZpcnN0UGFnZSI6InB1YmxpY2F0aW9uIiwicGFnZSI6InB1YmxpY2F0aW9uIn19

[346] PG&E response to SPD data request, RAMP-2024_DR_SPD_012-Q001, 01 at 2., August 19, 2024.

[347] PG&E response to SPD data request, RAMP-2024_DR_SPD_012-Q001, 01, at 2., August 19, 2024.

filing. PG&E should also clarify why EP&R is not considered a control[348] since it does appear to maintain a reduced level of consequence in the event of a dam breach.

CC4 – Information Technology Asset Failure (ITAF)

An ITAF is considered by PG&E to increase the likelihood of a catastrophic outcome if it coincides with one of the four drivers discussed above (D1-D4). While the goal for availability of the critical IT infrastructure is 99.9 percent, PG&E estimated that the probability of an ITAF occurring in tandem with a driver as 4.9 percent.[349] The likelihood of failure was assumed to increase by 50 percent if ITAF occurred at the same time as a major driver causing catastrophic dam failure. ITAF only has an impact on the frequency of LGUWR for outcomes associated with full dam breach. Total frequency for ITAF was computed as an event occurring once every 837 years. The total adjusted-risk attributed for ITAF is $17.6 million per year, or approximately 7 percent of the total adjusted-risk. SPD suggests that ITAF can also affect the consequence of a dam failure, for example, by impeding emergency response or degrading communication and situational awareness after an incident.

PG&E's method for calculating the probability of an ITAF occurring in tandem with a driver is unsophisticated. Workpaper CC-ITAFL-1_LGUWR Mapping and Freq calc.xlsx has a spreadsheet (LrgWaterRelease) with a list of IT assets that are mapped against "Consequence Multipliers." This concept is never explained and isn't methodologically tied since ITAF only affects the calculation of likelihood. Each Consequence Multiplier that is mapped to an asset exponentially increases the probability of at least one IT asset failing during a driving event, which in the CC-ITAFL-1_LGUWR Mapping and Freq calc.xlsx workpaper this is expressed as "1 - probability that no assets fail" or 4.9 percent.[350]

When asked about why it assumed that the likelihood of failure would increase by 50 percent when an ITAF occurred in tandem with a driver, PG&E's response was that it was based on qualitative subject matter expert (SME) judgment that remained unchanged from the 2020 RAMP.[351]

According to the workpaper GEN-LGUWR-07_Inputs_to_Bowtie.xlsx, this effectively results in the following changes to PFMs:

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348 Consistent with the definition in the RDF, PG&E defines a control as a currently established measure that modifies risk, such as standard operation/routine work that is undertaken as part of normal business operations and is not a new program, or an enhancement to an existing one. Controls have no end date.

349 PG&E confirmed to SPD that the 4.8 percent recorded in the RAMP narrative is a typo and that the 4.9 percent in workpaper CC-ITAFL-1_LGUWR Mapping and Freq calc.xlsx is the correct number.

350 This would be calculated as 1-(99.9 percent^50)=4.9 percent since PG&E determined that 50 IT assets were mapped to "Consequence Multipliers".

351 PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q007, 07.b, p. 1., July 22 2024

LoRE with an ITAF = [likelihood of failure for the PFM] * [0.0735][352]

LoRE without an ITAF = [likelihood of failure for the PFM] * [0.951]

Due to its unsophisticated approach and lack of transparency on many of the assumptions associated with ITAF, SPD strongly encourages PG&E to keep discussion of ITAF limited to the LGUWR risk in its 2027 GRC filing. If PG&E can develop a more robust approach to analyzing this as a true cross-cutting factor that influences multiple risks, SPD recommends PG&E to address that change in a future RAMP filing.

CC6 – Records and Information Management (RIM)

PG&E states that having a good system of RIM can reduce the likelihood of a LGUWR event by making it easy to locate needed records in a timely fashion. To account for poor RIM, PG&E said the ineffectiveness of RIM was 2 percent, which is accounted for by a multiplier to the financial consequences as seen in the 7-ConseqMult spreadsheet of the workpaper GEN-LGUWR-01_Risk Model Input File. However, there is limited indication in any workpapers as to how PG&E justified the magnitude of this multiplier specific to the 2024 RAMP filing. The CC-RECIM-2_PGE ERIM Consequence Multiplier.xlsx is in fact a workpaper from the 2023 GRC without a ReadMe worksheet to explain how the workpaper operates. The multiplier in this workpaper from April 2023 for Power Generation is 2 percent, but SPD recommends that PG&E should update this workpaper before it is submitted to the 2027 GRC with a justification for this number.

Most importantly, it is not clear why PG&E assumes that its own RIM system is inefficient and, therefore, requires an increasing multiplier on the financial consequences of LGUWR to account for that. Instead of increasing the financial consequence, it would make more sense that RIM would operate similarly to EP&R in that RIM actually reduces the consequence of a risk event. Moreover, the language in the LGUWR narrative is confusing since RIM is said to “reduce the likelihood” of LGUWR events, and yet within the risk model PG&E has created a consequence multiplier to capture the impact of RIM. In its 2027 GRC, SPD recommends that PG&E shouldprovide clear and detailed explanations regarding how the RIM cross-cutting factor operates in the context of LGUWR. The narrative in this chapter is limited to three sentences that do not justify a 2 percent increase to financial consequences.

The estimated total adjusted-risk for RIM is approximately $4.7 million per year, or 1.8 percent of the total adjusted-risk.

Consequences

Within the narrative of its RAMP filing, PG&E lists only uncontrolled release in unpopulated areas (O1) and uncontrolled release in populated areas (O2) as the outcomes of LGUWR. PG&E estimated fatalities

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[352] This is calculated as [likelihood of failure for the PFM] * [0.049] * [1+0.5] or [likelihood of failure for the PFM] *[0.0735]

and injuries as safety consequences from an O2 outcome by using inundation maps associated with a full dam breach during In Flow Design (IDF) and Fair Weather (FW) conditions.[353]

Similar to the 2020 RAMP, PG&E used the Dekay-McClelland method[354] to estimate the potential fatalities for IDF and FW scenarios for 47 dams. Population-at-Risk (PAR) was determined by counting the number of structures within the inundation zone from flood maps developed by PG&E for each dam and estimating one person per structure. Fatality was estimated from the PAR based on warning time and force of water on the structures. Injuries were estimated by applying a ratio from the National Oceanic and Atmospheric Administration (NOAA) of 1.87 injuries per fatality to the estimated fatality numbers. For the 2024 RAMP filing, PG&E updated the safety consequences for 13 dams[355] using the Reclamation's Life Loss Estimating Methodology (RCEM) or LifeSIM models. PG&E notes that it used a Poisson-Bernoulli distribution to model uncertainties for the safety consequences.

To calculate the financial consequences, PG&E followed the method used in the 2020 RAMP by computing the direct economic damage using average home prices, number of structures damaged, and infrastructure factors. Regarding the latter factor, such as roads, powerlines, and other infrastructure, PG&E assumed the cost of damage to infrastructure to be equal to the total damage to residential and commercial buildings. PG&E's internal financial costs consisted of cost of replacement for PG&E's dams and powerhouses, and foregone revenue from the loss of generation. However, in contrast with the 2020 RAMP, the 2024 RAMP filing estimates the duration for loss of revenue generation for a full dam breach to be 10 years instead of 1 year.[356]

Observations:

While the RAMP narrative only describes the two outcomes discussed above, within PG&E's workpapers the following eight sub-outcomes are listed and SPD provides an explanation for each:

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[353] For details of how the IDF and FW scenarios are structured see the ReadMe worksheet of GEN-LGUWR-14_CONFIDENTIAL_LifeLoss_Economic_Consequences. FW scenario means the dam fails during a sunny day and reservoir elevation is conservatively assumed to be at the maximum operating level (i.e., reservoir is at full capacity). IDF scenario means the dam fails when the large design flood is occurring.

[354] DeKay, Michael L., and Gary H. McClelland. "Predicting loss of life in cases of dam failure and flash flood." *Risk analysis* 13, no. 2 (1993): 193-205. https://www.researchgate.net/publication/230288562_Predicting_Loss_of_Life_in_Cases_of_Dam_Failure_and_Flash_Flood/link/5a743c100f7e9b20d490fcdf/download?_tp=eyJjb250ZXh0Ijp7ImZpcnN0UGFnZSI6InB1YmxpY2F0aW9uIiwicGFnZSI6InB1YmxpY2F0aW9uIn19

[355] These are the four FERC and nine spillway risk assessment dams described in D1 above.

[356] PG&E notes that these ten years would include the time for environmental clean-up, design, permitting, and construction of new dams and powerhouses.

Table 9-5: Description of the 8 Sub-outcomes for the LGUWR Risk Event

No.	Sub-outcome	Description
1	**FW (full dam breach)**	This is a full dam breach on a fair-weather day and is only related to O2.
2	**Flood (full dam breach)**	This is a full dam breach during IDF conditions and is only related to O2. It is primarily caused by the flood driver, although 2 percent of this risk is caused by the seismic driver but only for the Spaulding No. 1 dam.
3	**50% FW (partial dam breach)**	This means that there is a breach of at least a half of the dam on a fair-weather day and is only related to O2.
4	**25% FW (partial dam breach)**	This means that there is a breach of at least a quarter of the dam on a fair-weather day and is only related to O2.
5	**Lower bound (partial dam breach)**	This means there is a breach of less than a quarter of the dam (unclear if this is related to IDF or FW) and is only related to O2.
6	**Damaged State (High)**	This is a high degree of damage to a dam and only related to O1
7	**Damaged State (Medium)**	This is a mid-range degree of damage to a dam and only related to O1
8	**Damaged State (Low)**	This is a high degree of damage to a dam and only related to O1, it is only caused by the flood driver.

It should be noted that PG&E in its 2020 RAMP filing only had one outcome: dam failure. In its 2024 RAMP filing, PG&E did not clearly explain why the Outcomes were disaggregated by populated and non-populated regions and then further disaggregated by the eight outcomes listed in Table 9-4. From SPD's analysis of the data, the eight outcomes listed above should be sufficient for PG&E to complete its LGUWR risk analysis. SPD recommends removing the O1 and O2 distinctions when PG&E files its 2027 GRC. Additionally, SPD recommends that PG&E shoulddescribe the eight outcomes in greater detail in the 2027 GRC narrative.

PG&E claimed that for dams with larger spillway control structures, it also developed inundation maps for failure of these control structures during a FW scenario. However, it is not clear from the workpapers to which dams PG&E is referring. SPD recommends that PG&E should clearly explain to which dams it developed inundation maps for failure of spillway control structures when PG&E submits this information in the 2027 GRC.

The LGUWR inundation maps are not related to or influenced by FEMA flood maps. When asked why that is so, PG&E explained that:

> …the inflow design flood (IDF) for PG&E's dams are dam-specific and are often more severe than the storms used in the FEMA flood maps. Additionally, PG&E's inundation maps include volume of water

released from the reservoir, as well as downstream reservoirs impacted by cascading dam failures for both IDF and fair weather (FW) scenarios.[357]

PG&E did not define "more severe" in the quotation above. However, it is clear that PG&E is modeling the impact of floods in a manner that goes beyond FEMA's expectations. SPD recommends that PG&E explain in its GRC filing why it determined it is necessary to model floods in a manner that exceeds FEMA's expectations and what implications that decision has for the calculation of CoRE in the LGUWR risk event.

When asked about the definition of a PAR "structure," PG&E replied that structure is defined as a "residential, recreational vehicle parks, commercial, or government building."[358] As part of the same data request, PG&E provided a detailed example of the Rock Creek (Drum) multiple-arch dam along with the inundation maps used to estimate the number of structures at risk from a LGUWR risk event. SPD found that there are discrepancies between the time that the front wave arrives at a cross section in the inundation map compared with the data submitted in the GEN-LGUWR-14_CONFIDENTIAL_LifeLoss_Economic_Consequences.xlsx workpaper. For instance, according to the inundation map the front wave will arrive at cross section #15 within 52 minutes, but in the 2024 RAMP workpaper the wave will arrive at the same cross-section within 59 minutes. SPD recommends that PG&E conduct a data quality assessment between its inundation maps and the data submitted within its workpapers. Considering that this would only need to be done for 60 dams, SPD also recommends that PG&E do a quality check on the number of structures considered at risk from a LGUWR risk event. This quality check can prevent any under- or over-counting due to seasonality of structures, such as RV parks, or changes to structures since the last time the inundation maps were updated, which in the case of Rock Creek (Drum) dam appears to be 2018. SPD expects that this update should occur before PG&E files its 2027 GRC application, but at least it should be completed before PG&E files its next RAMP application in 2028.

PG&E did not properly cite the NOAA flood data, which led to the calculation of the injury ratio of 1.87. In a data request, PG&E provided a copy of the data used to calculate this ratio, which is based on 36 flooding events in California that occurred from 1996-2016.[359] SPD recommends that PG&E should provide a proper citation link to NOAA when first referencing this data in its 2027 GRC filing and clearly explain how it analyzed the NOAA data in the narrative of the filing.

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[357] PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q008, 08, p. 1, July 22 2024.

[358] PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q009, 09.a, p. 1, July 22 2024.

[359] PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q010, 10, p. 1, see also the Q10_2016 NOAA data spreadsheet in RAMP-2024_DR_SPD_005-Atch01.xlsx, July 22 2024.

The narrative and workpapers provide no explanation of the way RCEM or LifeSIM work.[360] The only additional information provided is that the data integrated into these models came from the US Army Corps of Engineers (USACE) National Structure Inventory (NSI) database. SPD recommends PG&E should include in its 2027 GRC a proper citation to information about the RCEM and LifeSim models and the NSI database. PG&E should also provide references to peer-reviewed scientific literature demonstrating the use of these models for measuring LGUWR fatalities. Moreover, seeing that PG&E is in the process of updating the remaining 47 dams using RCEM or LifeSIM, SPD recommends that the details of this process and a timeline for completion be included in the data update report.[361] In addition to using RCEM or LifeSIM to update the safety attribute for LGUWR, it would also be important to establish more accurate estimations of responses to uncontrolled releases. SPD recommends that PG&E consider the Response Time by Social Vulnerability Index (ReTSVI) or an equivalent approach to model the risk reduction benefits of a proper evacuation.[362] Such a model could help provide a more accurate measure of the benefits of the abovementioned Emergency Preparedness and Response cross-cutting feature.

PG&E has not clarified how the uncertainties for safety consequences associated with LGUWR addressed using Poisson-Bernoulli distribution differ from those addressed by PG&E's market-based non-linear risk scale. When filing the 2027 GRC, SPD recommends PG&E present its measure of risk, risk reduction, NPV Benefits and CBRs for LGUWR using both a linear and non-linear scale, which would be in line with the updated requirements in the RDF.[363]

Regarding the estimate of damage to infrastructure included in the financial attribute of the LGUWR consequence, PG&E provides no rationale for the assumption that the cost of damage to infrastructure should be equal to the cost of direct damages Moreover, beyond roads and powerlines, it is not clear what "infrastructure" includes in PG&E's analysis. SPD recommends that PG&E develop a more accurate approach to modeling the financial impact of an LGUWR in terms of damage to infrastructure along with a detailed description of what "infrastructure" includes and how the costs of each type of infrastructure is estimated. Without these details, the financial attribute may be severely underestimated or overestimated

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360 In a data request (PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q011, 11, p. 1, July 22 2024), PG&E provided the following links to both models:

Reclamation Consequence Estimating Methodology, Guidelines for Estimating Life Loss for Dam Safety Risk Analysis, July, 2015 https://www.usbr.gov/damsafety/documents/RCEM-Methodology2015.pdf

LifeSim Manual and Software, https://www.rmc.usace.army.mil/Software/LifeSim/

361 Due December 6, 2024, see D.24-05-064 at OP4 and at 27-28.

362 Hofflinger, Alvaro, Marcelo A. Somos-Valenzuela, and Arturo Vallejos-Romero. "Response time to flood events using a social vulnerability index (ReTSVI)." *Natural Hazards and Earth System Sciences* 19, no. 1 (2019): 251-267. https://nhess.copernicus.org/articles/19/251/2019/

363 D.24-05-064, Appendix A, Row 7 at A-8. The RDF states that "…if a utility chooses to address tail risk using the power law or other statistical approach and chooses to present Risk-Adjusted Attribute Levels by relying on a convex scaling function, then it must supplement its analysis by also presenting Risk-Adjusted Attribute Levels by relying on a linear scaling function."

depending on where the LGUWR risk event occurs. PG&E should provide a process and a timeline for creating a new method and approach for data collection to estimate the financial impact of LGUWR on infrastructure and have it included in the data update report.[364]

Regarding Foregone Revenue, PG&E did not provide a justification or workpapers for assuming that the duration for loss of revenue generation for full dam break should be 10 years instead of one year, as used on the 2020 RAMP. In a data request, PG&E claimed that the reason for this change from the 2020 RAMP to the 2024 RAMP is "based on PG&E's institutional experience with designing, permitting, and constructing large capital projects."[365] It is not clear to SPD how PG&E's institutional experience could have changed so dramatically in four years. In the same data request, PG&E listed examples, such as the 2020 failure of the Edenville and Sanford dams in Michigan, which have been in the process of being rebuilt over the last four years, and the Taum Sauk dam, which took four years to rebuild, to support this change. None of the examples resulted in ten years of lost revenue, although PG&E does note that the Teton and St. Francis dams were never rebuilt after a breach. Regardless, SPD recommends that PG&E should re-evaluate its decision to apply this change before submitting its 2027 GRC filing. From the information provided to SPD, it is clear that PG&E can only justify estimating the loss of revenue for four years instead of ten years. When PG&E can provide compelling evidence demonstrating a need to estimate loss of revenue for more than four years, SPD can re-evaluate this position. Additionally, it is not clear from the RAMP narrative or workpapers that Foregone Revenue is a financial consequence that is accruing 100% to ratepayers. SPD recommends that PG&E shouldto clearly explain how the Foregone Revenue documented in GEN-LGUWR-15_CONFIDENTIAL_Foregone Revenue.xlsx is a financial consequence that accrues to ratepayers in its 2027 GRC filing. Suppose any percentage of the financial consequence of Foregone Revenue does not accrue to ratepayers. In that case, SPD recommends that PG&E should remove it from its 2027 GRC filing as shareholder financial interests are not allowed to support rate case expenditure proposals.[366]

Controls and Mitigations

C001 – Maintenance

This control includes routine operations and maintenance (O&M) activities such as vegetation management, rodent abatement and general maintenance. These costs are not tracked for individual dams, so the costs are spread equally across all dams. A value of five percent was assigned for the value of effectiveness for maintaining the likelihood of a failure under normal operations conditions and flooding. PG&E notes that not performing LGUWR-C001 would increase PG&E's existing baseline risk to the higher "baseline risk."

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364 Due December 6, 2024, see D.24-05-064 at OP4 and at 27-28.

365 PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q013, 13 at 1, July 22 2024

366 D.16-08-018 at OP 6.

M001 – Internal Erosion Mitigations

PG&E implements this mitigation to minimize the potential for internal erosion failure modes for earth-fill and rockfill embankment dams. These installations reduce the likelihood of failure under normal operations driver (D3), but the mitigation has no impact on the consequences of a dam failure. The effectiveness of this mitigation is either provided a value of 5 percent, 50 percent, or 90 percent.

M002 – Spillway Remediations

PG&E implements spillway remediations to ensure its dams can safely pass the design flood events, including improvements to or rehabilitating spillway control structures, spillway chutes, gates, log booms, and operators. Spillway remediations reduce the likelihood of the flood driver (D1), but the mitigation has no impact on the consequences of dam failure. As part of its Capital Improvement Program (CIP), PG&E has listed 12 dams for spillway remediation projects in a twenty-year plan. For the 2024 RAMP, eight spillways will be in various stages of design, permitting, and construction from 2024 to 2030. The effectiveness of spillway remediation for reducing the likelihood of a risk event varies from 0.99 percent to 99.9 percent, most of which is based on either SME judgment or SQRA.

M003 – Seismic Retrofits

PG&E implements seismic retrofit mitigations to ensure dams and components will not fail under the seismic design loads. Seismic retrofits reduce the likelihood of the seismic driver (D2), but the mitigation has no impact on the consequences of dam failure. For the 2024 RAMP, PG&E identified two new seismic retrofit projects, the Upper Peak Dam seismic retrofit and the Belden intake structure retrofit.

M004 – Low-Level Outlet (LLO) Refurbishments

PG&E implements LLO refurbishments to ensure the reservoir can be drained during an emergency or for dam maintenance. Regulations require that the LLOs be properly maintained. PG&E notes that LLOs do not directly mitigate the three major drivers (flood, seismic, and normal) but are a critical component for lowering the reservoir after a seismic event or during the progression of internal erosion failure modes to prevent a more catastrophic failure. PG&E states that a deteriorated LLO will be added as a multiplier to the likelihood of either the seismic (D2) or normal operations (D3) risk driver. For the 2024 RAMP, only three LLO refurbishment projects are planned at the Fordyce, McCloud, and Spaulding 1 dams. For each of these projects, the effectiveness of reducing the likelihood of a risk event varies from 85 percent to 95 percent.

M005 – Physical Security

As a new mitigation for the 2024 RAMP, PG&E implements physical security mitigations to reduce the likelihood of a physical attack on a dam causing a LGUWR event. These mitigation projects will reduce the likelihood of the physical attack (D4) risk driver, but they have no impact on the consequences of dam failure. All physical security projects are expected to have a 25 percent effectiveness in reducing the likelihood of a risk event.

Foundational Programs

PG&E provides two foundational activities the Dam Safety Program (DSP) and Physical Security Program. Many aspects of the DSP that were included in the 2020 RAMP were continued in the 2024 RAMP. The current DSP includes the dam inspection program, engineering evaluations, the instrumentation and surveillance monitoring program, LLO and spillway gates testing program, and emergency action plans.

Asset Management System (AMS)

Hydropower dams are part of the AMS that PG&E has started to develop since the 2020 RAMP, and while no detailed cost information has been included in the 2024 RAMP, PG&E suggests that the following programs may be included within PG&E's 2027 GRC filing:

- Enhancement of the Asset Data Family
- Expansion of the Physical Data Asset Family
- Growth of PG's Risk Management Program
- Enhancement Programs
    - » Water System Maintenance Program
    - » Powerhouse Maintenance Program
    - » Vegetation Management Program
    - » Rodent Management Program
    - » Reservoir Debris Management Program
    - » Critical Support Facility Maintenance Program
- Increased AMS-informed Inspections
- Hydro Means and Work Methods Program
- Hydro Public Safety Program
- Enhanced meteorology and modeling
- AMS Staffing

Environmental and Social Justice (ESJ) Pilot Results

When discussing the results of its ESJ Pilot in the context of LGUWR, PG&E noted that it will spend $7.5 million in expenses and $288.4 million in capital on dams that impact Disadvantaged and Vulnerable Communities (DVC). Within the GEN-LGUWR-16_CONFIDENTIAL_Environmental_&_Social_Justice workpaper, PG&E also provided a summary of its LGUWR risk analysis and mitigation strategy across DVCs and non-DVCs.

Observations:

Controls

C001 – Maintenance

In the RAMP narrative, PG&E states that larger-scope maintenance activities can be capitalized and are treated instead as mitigations. When SPD asked PG&E what the threshold is for determining whether an activity should be included in this larger scope, PG&E replied that any component of its hydro assets that has an expected life of one year or greater can be capitalized. Additionally, repairs to the liner that exceed 100 square feet in a contiguous area and repairs to the expansion joint liner that cover at least 50 percent of the vertical height or horizontal length of the expansion joint can be capitalized.[367]

In the GEN-LGUWR-08_Inputs_to_CBR-Input workpaper, PG&E provided cost estimates of C001 not for each dam but for each of the seven watershed regions where the dams are located.[368] PG&E also included its 2023 actual expenditures, which in some cases are significantly higher than the 2024 forecasted expenses, as can be seen in Table 9-6:

[367] PG&E response to SPD data request, DR RAMP-2024_DR_SPD_005-Q015, 15, p. 1. For the general capital and expense standard used at PG&E, see also RAMP-2024_DR_SPD_005-Q015Atch01.pdf, July 22, 2024.

[368] Other than organizing the maintenance projects listed in this workpaper, PG&E did not provide any detailed information about these seven watershed regions. Staff were able to find an older mapping of these watersheds, although it appears two regions (Potter Valley and Helms) may have been demarcated from the five older designations: https://ia.cpuc.ca.gov/environment/info/aspen/pgehydro/nop/NOP%20Figure%201%20Map.PDF

Table 9-6: 2023 Ratio of Actual Costs Divided by 2024 Forecasted Maintenance Costs

Name of Maintenance Program	Ratio of 2023 Actual/2024 Forecast
Shasta Maint Reservoirs/Dams/Waterways	1.18
DeSabla Maint Reserv, Dams & Waterways	1.46
Drum Maint Reservoirs/Dam/Waterways	1.28
MLode Maint Reservoirs/Dams/Waterways	1.61
KCV Maint Reservoirs/Dams/Waterways	1.21
Helms Maint Reservoirs/Dams/Waterways	.96
Potter Valley Maint Res Dams & Waterways	2.07

Except for Helms, it appears that the 2024 forecasts are poorly estimated. SPD recommends that PG&E should include 2024 actual expenses in its 2027 GRC filing and require PG&E to clearly explain any differences between actuals and forecasts within its 2027 GRC filing.

Mitigations

During the 2027-2030 period, PG&E allocates approximately 36 percent ($403 million) of its proposed investment in mitigations to what it calls budget plugs.[369] While the details of these budget plugs will be analyzed below for each mitigation, in general, SPD recommends that PG&E shouldprovide much greater clarity in its 2027 GRC filing into how it expects to spend money to reduce risk associated with LGUWR. At present, all of PG&E's budget plugs have been given a mitigation effectiveness of 50 percent, which was then used to calculate a CBR. Given that the Commission does not know how this money will be spent or where it will be used to reduce risk, this mitigation effectiveness and CBR calculation is unsupported by any evidence and will require scrutiny after the 2027 GRC filing. As PG&E notes, the use of a budget plug was unique to the LGUWR chapter of the 2024 RAMP filing.[370] SPD strongly urges the Commission to direct PG&E to not use this approach again in a future RAMP or GRC filing.

LGUWR-M001 – Internal Erosion Mitigations

In total, PG&E has only proposed eight internal erosion mitigation projects with a total cost of $153 million between 2027 and 2030. This is significantly less than what is expected to be spent on this mitigation during the previous GRC cycle (approximately $422 million) according to the workpapers submitted with the 2024

[369] In workpapers these are described as budget plugs whereas in the RAMP narrative PG&E refers to this as a programmatic budget placeholder. Details can be found in PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q019, Q19_Budget Placeholder spreadsheet in RAMP-2024_DR_SPD_005-Atch01.xlsx, July 22 2024.

[370] PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q019, 19.b at 1, July 22 2024

RAMP.[371] Moreover, the vast majority of the expenses (74.2 percent)[372] associated with internal erosion mitigations are listed as part of a general budget plug. The $112 million budget plug is meant to potentially be used across any of the 60 dams, and it is supposedly enough money to cover the expenses of three dams per year.[373] However, based on the 2026 cost forecasts for five dams[374] listed in the Capital_Mitigation spreadsheet in the GEN-LGUWR-08_Inputs_to_CBR-Input workpaper, the average amount needed to support these mitigations is approximately $4.3 million per dam. PG&E's budget plug request for $12 million in 2028, therefore, aligns with its assessment of needing enough of a budget to cover three dams per year. Conversely, PG&E's request for a budget plug of $50 million in both 2029 and 2030 is significantly higher than what would be required to mitigate internal erosion at three dams. SPD recommends that PG&E clearly explain in its 2027 GRC filing why it requires this $112 million, how PG&E will spend this money to address internal erosion, and, most importantly, how much risk PG&E expects to mitigate at each dam where these investments will be made.

LGUWR-M002 – Spillway Remediations

While PG&E did provide a description of its CIP, it did not explicitly describe the Spillway Gates Refurbishment Projects. Since a large number of spillway gate refurbishment projects are listed in the Capital_Mitigation spreadsheet in the GEN-LGUWR-08_Inputs_to_CBR-Input workpaper, SPD recommends that PG&E in its 2027 GRC filing provide a clear explanation about the different types of projects that are associated with what PG&E calls Spillway Gates Refurbishment Projects and how PG&E expects such projects to reduce risk. Additionally, PG&E notes in its narrative that 16.6 percent of the M002 investments are considered budget plugs.[375] SPD recommends that PG&E should clearly explain in its 2027 GRC filing why it requires this budget of $122 million as well as the specific dams where it intends to implement new Spillway Remediations.

LGUWR-M003 – Seismic Retrofits

SPD has significant concerns with the costs associated with PG&E's suggested seismic retrofits. More than 85 percent of the M003 costs requested in the 2024 RAMP application are listed as a budget plug, amounting to $72 million. As with its other controls and mitigations, PG&E states that the budget plugs are intended to be enough money to cover the seismic retrofits for three dams. However, in its 2023 GRC

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371 See GEN-LGUWR-08_Inputs_to_CBR-Input workpaper

372 Note that using the GEN-LGUWR-08_Inputs_to_CBR-Input workpaper, SPD found that it is actually closer to 73.1 percent of expenses. PG&E should correct any errors in the workpapers or the narrative if they exist.

373 This is explained in the Project List spreadsheet in the GEN-LGUWR-03_CBR Input File workpaper.

374 Bucks, Lower (Diversion), Courtright, Pit 1, Relief and Wise Forebay. For this analysis, SPD set aside the forecasted costs for the Fordyce Leakage Reduction projects, which PG&E forecasted to have significantly reduced costs by 2027.

375 While the RAMP narrative and the Capital_Mitigation spreadsheet in the GEN-LGUWR-08_Inputs_to_CBR-Input workpaper show the budget plugs listed as $122 million, in the CBR Results spreadsheet of GEN-LGUWR-03_CBR Input File workpaper the budget plugs are listed as $105 million.

filing, even the most expensive annual budget for seismic retrofits at two dams (Upper Peak Dam and Belden Forebay) is $6 million each. Therefore (at most) PG&E should only require $18 million per year to cover the costs for seismic retrofits at three dams. According to GEN-LGUWR-08_Inputs_to_CBR-Input, PG&E's request for $30 million each in 2029 and 2030 is illogical based on PG&E's own workpaper. SPD recommends that PG&E should clearly explain in its 2027 GRC filing why it requires this budget of $72 million, describe the specific dams where it intends to implement new seismic retrofits, and clearly explain how much risk PG&E expects to mitigate at each dam where these investments will be made.

LGUWR-M004 – LLO Refurbishments

In a data request, SPD requested greater clarity on which of the 60 dams have a deteriorated LLO. PG&E explained that the Courtright, Fordyce, Balch Afterbay, Pit 3, Iron Canyon, Crane Valley, McCloud, Manzanita, Lake Almanor, and Spaulding No. 1 dams meet the criteria of "deteriorated" LLO in need of capital funding to repair or replace. In this context, deteriorated is defined as components within the LLO that are nearing end-of-life or in a degraded condition needing to be repaired or replaced.[376] Moreover, PG&E states that a deteriorated LLO multiplier is integrated into the LoF_Pre variable in the Ref_PFMs spreadsheet of the GEN-LGUWR-07_Inputs_to_Bowtie.xlsx workpaper.[377] However, there currently is no way to determine the quantitative impact a deteriorated LLO has on the LoF_Pre variable. SPD recommends that PG&E should explain how this deteriorated LLO multiplier is impacting the LoF_Pre variable in its 2027 GRC filing.

PG&E's LLO refurbishments include a budget plug of $78 million or approximately 77 percent of the total costs requested for this mitigation. According to GEN-LGUWR-08_Inputs_to_CBR-Input workpaper, the maximum cost of an LLO refurbishment could be $13 million, but the average cost is closer to $1 million. PG&E intends to implement upwards of 10 LLO refurbishment projects at a given time, but in most years it forecasted approximately $20 million per year to cover these projects. Thus, PG&E's budget plug requests in 2029 and 2030, for $25 million and $30 million respectively, are abnormally high. SPD recommends that PG&E should clearly explain in its 2027 GRC filing why it requires this budget of $78 million, describe the specific dams where it intends to implement new LLO refurbishments and clearly explain how much risk PG&E expects to mitigate at each dam where these investments will be made.

LGUWR-M005 – Physical Security

According to the Capital_Mitigation spreadsheet in the GEN-LGUWR-08_Inputs_to_CBR-Input workpaper, between 2027-2030 PG&E is explicitly asking for funding to support implementing physical security mitigations at 26 dams at a rate of approximately $1.07 million per dam. Between 2027-2030 PG&E has also requested a budget of approximately $20 million as a budget plug for future physical security

[376] PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q017, 17.a at 1, July 22 2024

[377] PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q017, 17.c at 1, July 22 2024. SPD assumes that the LoF_Pre variable stands for the calculation of a likelihood of dam failure before mitigation, but this is not defined in PG&E workpapers or in the data request response.

projects. That would mean potentially implementing these physical security mitigations at an additional 20 dams within the next GRC cycle. During 2023, the only year PG&E provided actual data in its 2024 RAMP filing, PG&E only implemented seven physical security mitigation projects. By 2027, PG&E aims to implement 21 physical security mitigation projects, and it requests an additional $6 million as a budget plug, which SPD assumes would support an additional six physical security mitigation projects. Based on the information provided in the GEN-LGUWR-08_Inputs_to_CBR-Input workpaper, SPD is skeptical that PG&E can oversee that many projects within a short period. SPD recommends that PG&E should clearly explain in its GRC filing why it requires this budget of $20 million as well as the specific dams where it intends to implement new physical security mitigations.

Bundled Projects

While assessing the GEN-LGUWR-08_Inputs_to_CBR-Input workpaper, it became apparent to SPD that some mitigation projects were lumped together into what PG&E describes as bundled projects. These were not described anywhere in the RAMP narrative, but in the ReadMe worksheet for that workpaper they are described as such:

> Projects that are relatively similar in scope are bundled together for calculating risk effectiveness.

In response to an SPD data request about bundled projects, PG&E replied that it is currently grouping mitigation and maintenance activities to repair or upkeep a component (such as a spillway gate) because PG&E's preliminary model does not estimate risk for replacement or repairs of smaller subcomponents.[378] Moreover, SPD requested PG&E to provide detailed risk reduction, cost, and CBR calculations for the projects within each bundle. This resulted in 33 disaggregated projects, only four of which have CBRs significantly higher than 1.[379] The problem with this bundled project approach is that, in some cases, PG&E may have bundled expense projects along with capital projects, but they are all considered capital projects when bundled. This was done by adding paint recoats to spillway gate projects, which appears to have passed PG&E's internal threshold for distinguishing between capital and expense projects. However, SPD does not know that a paint recoat would last more than one year and make it eligible as a capital project.[380] This bundled approach was done in both the 2023 GRC and now again in the 2024 RAMP. Bundled Groups 1, 4, 5, 6, and 7 all include paint recoats to spillway gate projects. It is possible the Commission or intervenors did not catch this issue during the 2023 GRC. This did not receive the scrutiny it deserves because PG&E did not create an equivalent of the GEN-LGUWR-08_Inputs_to_CBR-Input workpaper in its 2023 GRC filing.[381] In its 2027 GRC filing, SPD recommends that PG&Eshould disaggregate these five

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378 PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q016, 16.a at 1, July 22, 2024.

379 See PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q016, Q16_Bundled Projects spreadsheet in RAMP-2024_DR_SPD_005-Atch01.xlsx, July 22, 2024.

380 See PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q015, 15 at 1, July 22, 2024. See discussion above when SPD discussed these thresholds in the context of Controls.

381 PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q018, 18 at 1, July 22, 2024.

bundled groups and that PG&E file an Inputs to CBR-Input workpaper for every risk within the 2027 GRC filing. SPD recommends that PG&E consider removing the paint recoat projects from its CapEx numbers and instead designate them as OpEx.

Foundational Activities

Overall, it is not clear why PG&E no longer describes DSP as a Control as was done in the 2020 RAMP and 2023 GRC. PG&E informed SPD through a data request response that, as presented in the 2024 RAMP, the components of DSP do not reduce risk on their own, therefore it is not possible to quantitatively calculate risk reduction benefits for this program.[382] However, PG&E also clarified that "the risk reduction benefits for EAP can be calculated by taking the difference in consequences between a scenario with an EAP program (current life safety consequence values) and a scenario with no EAP program (assuming limited to no warning for downstream population)."[383] Based on this clarification, staff recommend that PG&E return the EAP to a Control in its 2027 GRC filing and provide a full cost-benefit analysis of this Control.

Asset Management System (AMS)

PG&E's narrative of the AMS is severely lacking in detail. It remains to be seen in the GRC filing whether the AMS is properly classified as a Foundational Activity or if some of the bulleted items should be considered a Mitigation that will reduce risk. Additionally, any costs submitted as part of PG&E's 2027 GRC associated with the AMS must be scrutinized for whether they are properly classified as capital or expense investments.

SPD encourages PG&E to spend more time and effort on one of the components of the AMS: Hydro Public Safety Program. Regarding the 2024 RAMP filing, there is limited engagement with the general public in PG&E's use of Controls and Mitigations to reduce risk. Public engagement programs should reduce the consequence of a risk event, and PG&E should estimate that risk reduction will be as high as possible. The scientific literature on the importance of public outreach in a dam breach is extensive.[384] SPD encourages PG&E to take these approaches seriously and SPD expects public engagement programs to be integrated within the LGUWR risk model when PG&E submits its 2028 RAMP.

ESJ Pilot Results

[382] PG&E response to SPD data request, RAMP-2024_DR_SPD_012-Q003, 3a at 2, August 19, 2024.

[383] PG&E response to SPD data request, RAMP-2024_DR_SPD_012-Q003, 3b at 2, August 19, 2024.

[384] Tullos, Desiree. "How to achieve better flood-risk governance in the United States." *Proceedings of the National Academy of Sciences* 115, no. 15 (2018): 3731-3734; McDaniels, Timothy L., Robin S. Gregory, and Daryl Fields. "Democratizing risk management: Successful public involvement in local water management decisions." *Risk analysis* 19, no. 3 (1999): 497-510.

Regarding the ESJ Pilot results, it is not clear why PG&E did not complete the calculation to include a CBR calculation for all mitigation programs across the DVC and non-DVCs in GEN-LGUWR-16_CONFIDENTIAL_Environmental_&_Social_Justice workpaper. Additionally, it is not clear why PG&E presented the safety consequences in natural units rather than the monetized attribute value as is required by D.22-12-027.

Alternatives Analysis

Observations:

While PG&E provided two alternative projects for comparison against one individual project within the Internal Erosion (M001) program at only one dam, this information is not particularly helpful to a decision-maker. PG&E confirmed that it created alternatives for each of the projects listed in the Capital_Mitigation sheet of the GEN-LGUWR-08_Inputs_to_CBR-Input workpaper.[385] With this in mind, in its 2027 GRC filing, SPD recommends that PG&E provide two portfolios with a mixture of alternatives across all 60 of its dams and across all five of its mitigation programs. The results of this analysis can be presented identically with the CBR Results (aggregated) spreadsheet in the GEN-LGUWR-03_CBR Input File workpaper. This, in effect, would add two spreadsheets to that workpaper, CBR Results Alternative Portfolio A (aggregated) and CBR Results Alternative Portfolio B (aggregated). This kind of analysis would provide meaningful information to a decision-maker. It is not necessary in such an alternative analysis for PG&E to exhaust every scenario possible, but PG&E should provide at least two professionally designed alternative portfolios for a decision-maker's consideration in its 2027 GRC filing.

SPD recommends PG&E also consider an additional approach to alternatives: dam removal. Although this can be a long and politically complex approach to execute, once complete, this mitigation strategy would eliminate the likelihood of an LGUWR risk event entirely. The scientific literature on dam removal is now extensive, with relevant case studies in California along the Klamath River and decision-support frameworks for removing dams across Northern California.[386] These case studies and frameworks should be used by PG&E to properly estimate the risk reduction and costs associated with dam removal on at least two of its dams that, according to operational constraints, PG&E views as potential candidates for removal. In its 2027 GRC filing, PG&E could present dam removal and its associated costs as a substitute for Alternative Portfolio B described above.[387]

[385] PG&E response to SPD data request, RAMP-2024_DR_SPD_005-Q021, 21, p. 1, July 22 2024

[386] East, Amy E., and Gordon E. Grant. "A watershed moment for western US dams." *Water Resources Research* 59, no. 10 (2023): e2023WR035646; Jumani, Suman, Lucy Andrews, Theodore E. Grantham, S. Kyle McKay, Jeffrey Duda, and Jeanette Howard. "A decision-support framework for dam removal planning and its application in northern California." *Environmental Challenges* 12 (2023): 100731.

[387] As an example, PG&E should consider SCE's presentation of dam removal as an alternative mitigation in its 2022 RAMP filing. See SCE 2022 RAMP, Chapter 12 at 33-34 and at 42-44.

CBR Calculations

Four of the aggregated mitigation categories for LGUWR have CBR scores lower than 1 for the 2027 to 2030 period. PG&E believes it must continue with the five mitigation programs listed above for the following reasons:

1. PG&E must remain in compliance with FERC and California Department of Water Resource's Division of Safety of Dams (DSOD) regulations. PG&E also states that larger projects tend to have lower CBRs, which include mitigations such as the seepage mitigation project for Lake Fordyce and spillway improvement projects for McCloud, Tiger Creek Regulator, and Butt Valley dams.
2. PG&E provides a list of modeling limitations relevant to both a full dam breach and failure of critical components (a partial dam breach).
3. Mitigations reduce the need for PG&E to alter its operations. To implement emergency repairs, PG&E would also need to divert engineering, planning, and permitting resources from planned mitigation projects. PG&E believes that responding to a dam safety incident is almost always significantly more expensive than proactively maintaining the dams and their components.
4. PG&E states that since there is interest in the topic of risk tolerance in the RDF Proceeding, it has selected mitigations that ensure safety is a top priority even if PG&E's risk modeling indicates the costs are higher than the modeled value of risk reduction.

Observations:

The large majority (90.8 percent) of the individual mitigation projects submitted by PG&E to reduce the risk of an LGUWR event have a CBR lower than 1. SPD recognizes that PG&E must select mitigations that ensure the company meets FERC and DSOD requirements regardless of the results of a CBR calculation. Additionally, some of PG&E's larger capital projects have particularly low CBRs. However, a look at PG&E's ten largest investments in mitigation projects demonstrates that there is considerable variation:

Table 9-7: NPV Cost and CBR for PG&E's Ten Largest Investments during 2027-2030

	Project	Dam	2027-2030 Capital Cost NPV with PVRR ($M)	2027-2030 Program CBR
1	McCloud Spillway Improvements SAIP	McCloud	$395.01	0.023
2	Relief Dam - Shotcrete Overlay	Relief	$85.91	0.172
3	Relief Dam - Geomembrane Liner	Relief	$73.44	0.201
4	Pit 6 Spillway Gate Projects	Pit 6	$30.26	2.460
5	Belden Spillway Imprv Walls SAIP IRRM	Belden Forebay	$29.70	3.928
6	Pit 7 Spillway Gate Projects	Pit 7	$27.94	2.027
7	Relief Dam-Resurface Upstream Liner	Relief	$24.36	0.607
8	Belden Forebay Spillway Upgrades SAIP - LT	Belden Forebay	$18.55	0.817
9	Spaulding 1 Dam Repl Intake Rack and LLO	Spaulding No. 1	$14.01	5.116
10	Lake Almanor Spillway Joint Rpl SAIP - ST	Lake Almanor	$13.86	0.041

It is not always the case that large investments and/or projects required by FERC and DSOD would have a CBR lower than 1. Moreover, four of the 10 largest investments have a CBR greater than 1. SPD currently takes no position on whether PG&E's proposed mitigations are acceptable based on the CBRs presented in the 2024 RAMP filing.

However, there is a fundamental problem with the way PG&E has prioritized the proposed mitigations. As far as SPD can determine, PG&E has not presented why it prioritized constructing the proposed 545 mitigation projects at only 38 dams in the 2027-2030 GRC cycle, thereby leaving 22 high-risk dams "unmitigated." PG&E might argue that its budget plugs are intended to be spread out over all 60 dams. This hypothetical position further highlights how problematic these budget plugs are for decision-makers. The use of budget plugs prevents decision-makers from knowing whether PG&E is properly prioritizing its investments in mitigations to address the riskiest dams first.

PG&E's insistence on using one reporting tranche per dam makes it more difficult to assess whether it has properly prioritized its investments. By utilizing the nine LoRE and CoRE tranches, as discussed above, SPD was able to create the following analysis of PG&E's proposed mitigations:

Table 9-8 CBR Calculations by LoRE and CoRE Tranche

Tranche	Name of Dams 2027	2027-2030 Foundational Activity Cost NPV ($M)	2027-2030 Total Cost NPV ($M)	2027-2030 Program Risk Reduction NPV ($M)	2027-2030 Total CBR (Col. 5/(Col.3+Col.4))
1	Pit 3 Pit 5 Open Conduit Fordyce Rock Creek (Feather) Salt Springs Pit 4 Pit 6	$3.50	$65.60	$166.19	2.40486
2	Spaulding No. 1 Belden Forebay Lake Almanor Pit 7 Spaulding No. 2 Bucks, Lower (Diversion) Peak, Upper	$4.26	$148.27	$548.72	3.59757
3	Butt Valley Round Valley Macumber Kidd Lake Auxiliary Halsey Forebay No. 1 Cape Horn Wise Forebay	$0.49	$16.88	$22.41	1.29072
4	Iron Canyon Spaulding No. 3 Bear, Upper Grizzly Forebay Bear, Lower No. 1 Crane Valley Cresta	$0.03	$3.64	$14.50	3.95516
5	Kidd Lake McCloud Scott Tabeaud Lake Valley	$0.02	$399.62	$11.99	0.03001

Tranche	Name of Dams 2027	2027-2030 Foundational Activity Cost NPV ($M)	2027-2030 Total Cost NPV ($M)	2027-2030 Program Risk Reduction NPV ($M)	2027-2030 Total CBR (Col. 5/(Col.3+Col.4))
5	Balch Diversion Tiger Creek Regulator Lake Valley Auxiliary Philbrook Blue, Upper (Moke) North Battle Creek Rucker	$0.11	$2.13	$0.33	0.14849
7	Relief Bucks Lake (Storage) Bear, Lower No. 2 Tiger Creek Afterbay Pit 1 Wishon Courtright	$0.53	$34.25	$25.69	0.73860
8	Strawberry Wishon Auxiliary No. 1 Rock Creek (Drum) South Halsey Forebay No. 2 Rock Creek (Drum) Arch Halsey Afterbay Balch Afterbay	$0.02	$0.06	$0.002	0.02968
9	Drum Forebay Lyons Pit 7 Afterbay Rock Creek (Drum) North Blue Lake (Drum) Manzanita	$0.01	$3.11	$0.0002	0.00006

The red highlights in Table 9-8 indicate a dam that will not receive any proposed mitigations during the 2027 GRC cycle. From SPD's analysis, it appears that PG&E intends to use the 2027 GRC cycle to fund several projects in the top two LoRE and CoRE tranches and mitigate a significant amount of risk that exists at those 14 dams in the top 2 tranches. However, five dams in the third and fourth LoRE and CoRE tranches will be left entirely unmitigated in this 2027 GRC cycle. Even Iron Canyon dam, which PG&E ranked as having the 10th highest level of risk due to a significant unexplained increase in Foregone Revenue, will remain unmitigated throughout the 2027 GRC cycle. It is also confusing that the fifth tranche exhibits the largest investment in a capital-based mitigation, which is dominated by the McCloud Spillway

Improvement project.[388] SPD recommends that PG&E should create nine tranches using the LoRE and CoRE approach in addition to the current method of one tranche per dam (if PG&E wishes to retain that approach). Requiring PG&E to provide the nine LoRE and CoRE tranches will ensure that decision-makers can properly assess the prioritization of mitigations to reduce the risk of LGUWR risk events.

Additionally, operational considerations must play a factor when determining the best way to optimize PG&E's use of water resources in California. However, in its RAMP narrative, PG&E needs to connect an individual mitigation program to these operational considerations better. In its 2027 GRC filing, SPD recommends that PG&E shoulddescribe explicitly how each of its five mitigation programs can support the operational considerations discussed in the 2024 RAMP narrative.[389]

PG&E should explicitly state its risk tolerance for a LGUWR event and identify how its risk tolerance might diverge from that of its ratepayers. The distinction of the eight outcomes used in the 2024 RAMP implies that PG&E's risk tolerance is quite low. PG&E appears to have little to no appetite for financial consequences that are accumulated from even a Damage State (Low) outcome. SPD recommends that PG&E in its 2027 GRC filing should explicitly explain its risk tolerance for LGUWR events and how that has impacted its risk mitigation selection.

SPD recognizes the George Box aphorism that "all models are wrong but some are useful." Bearing this in mind, PG&E's listing of its modeling limitations seems odd in a section titled "Factors Affecting Mitigation Selection." The current risk model should provide PG&E and decision-makers the information they need to move forward with a mitigation strategy for reducing risk. It is not clear why a list of ideas that have yet to be quantified within that model should be considered a factor in the Commission's decision-making process. However, since PG&E has mentioned this limitation of its model, SPD recommends that PG&E should file an update to these modeling limitations in PG&E's report of data collection efforts by December 6, 2024 as required by D.24-05-064.

Summary of Findings

1. Designating a tranche for each dam does not meet the definition of a tranche in the Risk-based Decision-making Framework. This approach to designating tranches is also unhelpful to a decision-maker because it is difficult to assess the appropriateness of prioritizing investments in mitigations.
2. In Informal Comments, Cal Advocates has presented evidence of drownings occurring in PG&E's water conveyance system.
3. SPD discovered that the primary reason for the rise in risk ranking for Iron Canyon dam is due to Foregone Revenue in the event of a breach at Iron Canyon.

[388] See discussion of McCloud and Iron Canyon dams in the Tranches section above.

[389] The details about the operational considerations are discussed in PG&E 2024 RAMP (PG&E-5) Chapter 1 LGUWR at 1-59.

4. Between the Test Year 2023 GRC filing and the 2024 RAMP filing, the McCloud dam exhibited a significant decrease in risk ranking relative to other dams in PG&E's territory. However, the reason for the change is not clearly explained in the 2024 RAMP narrative or workpapers.
5. PG&E's collaboration with FERC's Semi-Quantitative Risk Assessment (SQRA) program has resulted in four out of 60 dams having fully modeled PFMs. At present, 31 of the dams still only have one PFM per driver, while the four dams that participated in the SQRA have many PFMs for the Flood, Seismic and Normal drivers. This indicates that SQRA would have identified additional PFMs for each of these 31 dams.
6. It is unclear how PG&E's risk model will change once it applies SQRA and/or introduces new PFMs to all of the 60 high- or significant-hazard dams in PG&E's territory. PG&E's piecemeal approach to updating the LGUWR risk model makes it difficult to know if the utility is properly prioritizing its mitigations across the 60 dams.
7. The shift in risk modeling of the flood, seismic and normal drivers from the 2020 RAMP to the 2024 RAMP is significant but the justification for doing so is unclear.
8. Between the 2020 and PG&E 2024 RAMP filings, 13 dams witnessed significant increases or decreases in the value of the "probability of failure" variable associated with the flood driver.
9. Within workpapers it is apparent that the physical attack driver is only relevant to the Fair Weather full dam breach outcome. However, PG&E does not explain why this is the case.
10. At present the narrative explanation of RIM in this chapter is limited to three sentences that do not provide justification for a 2 percent increase to financial consequences.
11. Many of the assumptions underlying PG&E's models are left unstated or hidden within workpapers.
12. In its 2024 RAMP filing, PG&E did not clearly explain why Outcomes were disaggregated by populated and non-populated regions and then further disaggregated by the eight outcomes listed in Table 9-4. From SPD's analysis of the data, the eight outcomes listed above should be sufficient for PG&E to complete its LGUWR risk analysis.
13. PG&E has not clarified how the uncertainties for safety consequences associated with LGUWR that were addressed using a Poisson-Bernoulli distribution differ from those addressed by PG&E's market-based non-linear risk scale.
14. SPD found discrepancies between the time the front wave arrives at a cross section in the inundation map compared with the data submitted in workpapers.
15. PG&E is modeling the impact of floods in a manner that goes beyond FEMA's expectations but PG&E does not provide a clear explanation of why that is so or what implications it has for the calculation of CoRE.
16. With regard to Foregone Revenue, PG&E did not provide a justification or workpapers for assuming that the duration for loss of revenue generation for full dam break should be 10 years instead of 1 year. Additionally, it is not clear from the RAMP narrative or workpapers that Foregone Revenue is a financial consequence that is accruing 100% to ratepayers.
17. SPD finds that PG&E's 2024 forecasts for OpEx of Controls are poorly estimated.
18. PG&E allocated a significant amount ($403 million) of its investment to budget plugs, which represent unverifiable mitigations spread out across all dams with the same risk reducing efficiency of 50%.

19. PG&E states that a deteriorated LLO multiplier is integrated into its workpaper, but there currently is no way to verify the quantitative impact of a deteriorated LLO due to the way the workpaper is structured.
20. In five instances, PG&E combined paint recoats to spillway gate projects, which it described as "bundled projects," and listed them as capital expense projects.
21. PG&E stated that operational considerations influenced its selection of a mitigation program to reduce the risk of an LGUWR event, but did not explain the connection between the operational considerations and any of the five mitigation programs.
22. PG&E has stated that risk tolerance influenced its selection of mitigations that ensure safety is a top priority, but it never explicitly explained what risk tolerance level it set in the context of the LGUWR risk event. Moreover, PG&E did not explain the implicit level of risk tolerance embedded in the mitigation selections.
23. PG&E's narrative of the AMS is severely lacking in detail. It remains to be seen whether the AMS is properly classified as a Foundational Activity or whether some of the bulleted items should be considered a Mitigation that will reduce risk.
24. PG&E provided two alternative projects for comparison against one individual project within the Internal Erosion (M001) program at only one dam, but this limited amount of information is not particularly helpful to a decision-maker.
25. As far as SPD can determine, PG&E has not presented a clear reason why it prioritized constructing the proposed 545 mitigation projects at 38 dams in the 2027-2030 GRC cycle, thereby leaving 22 high-risk dams "unmitigated."
26. PG&E's use of budget plugs spread out over all 60 dams highlights how problematic this budget plug approach is for decision-makers. The use of budget plugs prevents decision-makers from knowing whether PG&E is properly prioritizing its investments in mitigations by buying down the riskiest dams first
27. There is limited engagement with the public regarding PG&E's use of Controls and Mitigations to reduce risk. Public engagement programs should reduce the consequence of a risk event and PG&E should estimate that risk reduction to the extent possible.

Recommended solutions to address findings and deficiencies

For the TY 2027 GRC, SPD recommends that:

1. PG&E should create nine tranches using the LoRE and CoRE approach in addition to the current method of one tranche per dam (if PG&E wishes to retain that approach). Requiring PG&E to provide the nine LoRE and CoRE tranches will ensure that decision-makers can properly assess the prioritization of mitigations to reduce the risk of LGUWR risk events.
2. PG&E consider modeling the safety and financial consequences as well as the likelihood of citizens being injured or drowning after falling into PG&E's water conveyance system as well as any mitigations to reduce the likelihood or consequence of such a risk event in its 2028 RAMP filing.

3. PG&E provide an explanation of why Foregone Revenue has been modeled at such a higher degree for Iron Canyon in its 2027 GRC filing.
4. PG&E provide a more detailed explanation for why the McCloud dam's risk score relative to the other dams dropped considerably in the 2024 RAMP filing
5. An updated list of PFMs be included as part of PG&E's testimony in its GRC.
6. PG&E should explain in detail in its 2027 GRC filing what exactly changed between the 2020 RAMP and 2024 RAMP filings with its flood, seismic, and normal drivers that resulted in such a significant shift in the modeling.
7. PG&E should properly explain why it made the changes to the "probability of failure" variable associated with the flood driver at 13 dams in its 2027 GRC filing.
8. PG&E should explain why it does not consider the potential for a physical attack to result in partial dam breaches in its 2027 GRC filing.
9. In its 2027 GRC filing, PG&E should provide clear and detailed explanations regarding how the RIM cross-cutting factor operates in the context of LGUWR.
10. PG&E should provide sufficient citations of workpapers and external resources so that stakeholders evaluating the PG&E 2027 GRC Application can easily locate the source of the information discussed in the narrative of testimony.
11. The Outcome 1 and Outcome 2 distinction be removed when PG&E files its 2027 GRC. Additionally, PG&E should describe the eight "sub-outcomes" in greater detail in the 2027 GRC narrative.
12. When filing the 2027 GRC, PG&E present its measure of risk, risk reduction, NPV Benefits and CBRs for LGUWR using both a linear and non-linear scale.
13. PG&E conduct a data quality assessment between its inundation maps and the data submitted within its workpapers as well as a data quality assessment on the number of structures considered at risk from a LGUWR risk event. SPD expects these assessments to occur before PG&E files its 2027 GRC application, but at least completed before PG&E files its next RAMP application in 2028.
14. PG&E should explain in its GRC filing why it determined it is necessary to model floods in a manner that exceeds FEMA's expectations and what implications that decision has for the calculation of CoRE in the LGUWR risk event.
15. Regarding the Foregone Revenue estimate, PG&E should adjust its assumption that the duration for loss of revenue generation for full dam break should be 10 years instead of 1 year. Additionally, in its 2027 GRC filing, PG&E should clearly explain how the Foregone Revenue is a financial consequence that accrues to ratepayers. If any percentage of Foregone Revenue does not accrue to ratepayers, it should be removed from PG&E's 2027 GRC filing.
16. PG&E should include 2024 actual operating expenses for Controls in its 2027 GRC filing and require PG&E to clearly explain any differences between actuals and forecasts within its 2027 GRC filing.
17. PG&E should provide greater clarity in its 2027 GRC filing into how it expects to spend the money associated with a "budget plug" to reduce risk associated with LGUWR. Moreover, PG&E should not use a budget plug approach again in a future RAMP or GRC filing.

18. PG&E should clarify how the deteriorated LLO multiplier impacts risk model variables in its 2027 GRC filing.
19. PG&E should disaggregate the five bundled groups, bundle groups 1,4, 5, 6, and 7, in its 2027 GRC filing.
20. In its 2027 GRC filing, PG&E should describe explicitly how each of its five mitigation programs can support the operational considerations discussed in the 2024 RAMP narrative
21. In its 2027 GRC filing, PG&E should explicitly explain what its risk tolerance is for LGUWR events, how PG&E's risk tolerance might diverge from that of its ratepayers, and how risk tolerance has impacted PG&E's risk mitigation selection.
22. Any costs submitted to the 2027 PG&E GRC associated with the AMS should be included in a detailed narrative of the program and explain why they have been classified as a foundational activity or mitigation.
23. PG&E provide two portfolios with a mixture of alternatives across all 60 of its dams and across all five of its mitigation programs. As an alternative portfolio, PG&E could also present dam removal and its associated costs. PG&E does not need to exhaust every scenario possible, but it needs to provide two professionally designed alternative portfolios with sufficient details for a decision-maker's consideration in its 2027 GRC filing.
24. Integrating public engagement programs into the LGUWR risk model when PG&E submits its 2028 RAMP.

10. Failure of Electric Distribution Underground Assets

Risk Description

The Failure of Electric Distribution Underground Assets risk is presented in PG&E-4, Chapter 5 of PG&E's 2024 RAMP Report. This risk captures potential events and consequences posed by the failure of electric distribution underground assets (including both radial and network systems) or the lack of remote operation functionality that may result in public or employee safety issues, property damage, environmental damage, or the inability to deliver energy.

In the 2020 RAMP, the network portion of the assets, which consisted solely of underground distribution network systems in Oakland and San Francisco, was treated as a standalone RAMP risk, while the non-network underground electric distribution asset sub-group did not rise to the level of a RAMP risk. In the 2024 RAMP, all electric distribution underground assets were consolidated into this single RAMP risk.

The Failure of Electric Distribution Underground Assets risk has the tenth-highest 2027 Test Year Baseline Safety risk value and the fifth-highest 2027 Test Year Baseline Total Risk Value of PG&E's 32 Corporate Risk Register risks.

Table 10-1: Risk Overview

FAILURE OF ELECTRIC DISTRIBUTION UNDERGROUND ASSETS	
Definition	The failure of distribution UG (including radial and network) assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.
In Scope	Failure of primary distribution voltage UG radial and network assets.
Out of Scope	Failure of assets associated with UG assets for the transmission system. The associated safety consequences related to dig-ins or electrical contact are included in the Public Contact with Intact Energized Electrical Equipment risk.
Data Quantification Sources	PG&E records of radial outage data from 2015 to 2022 PG&E records of network equipment failures from 2008 to 2022 Electric incident reporting (EIR) dataset which maintains injury/fatality incidents within PG&E service territory Historical outage cost data from 2017 to 2020

Observations:

1. PG&E only vaguely cited "to better manage the risk associated to this asset family"[390] as the reason for consolidating all electric distribution underground assets into a single risk in the 2024 RAMP.

   The most direct effect of the consolidation is that it causes the non-network Failure of Electric Distribution Underground Assets to fall within the purview of a RAMP risk since this asset group would not otherwise have risen to the level of a standalone RAMP risk. This observation is based on the fact that, in the 2020 RAMP, the Failure of Electric Distribution Underground Assets (which, in 2020, did not include the addition of the failure of network assets risk) was only 13th out of 26 risks, or at the 50th percentile, using a safety-only risk score ranking.[391] At the 50th percentile, it fell below the top 40 percent safety-only risk score RAMP risk cutoff mark established in the S-MAP Settlement Agreement. In the 2020 RAMP, even the Failure of Electric Distribution Network Assets risk was only ranked 10th highest out of 26 risks, or at the 38th percentile, just barely high enough to qualify as a RAMP risk in 2020 based on the top 40 percent cutoff mark.

   Consolidating these two electric distribution underground asset groups into a single RAMP risk ensures that the combined assets have sufficient safety risks to meet the 40th percentile threshold to be included in the 2024 RAMP and that all electric distribution underground assets will be examined in the RAMP.

2. All the data quantification sources listed in line 4 of Table 10-1 are based on actual network equipment failures and outages (i.e., they all appear to be lagging indicators). It is unknown whether other data sources are not listed in the table. SPD recommends that PG&E incorporate leading indicator data into the data quantification sources. For example, data obtained from equipment condition testing and routine inspections could be valuable sources of leading indicator data.

[390] PG&E-4, Chapter 5, Page 5-3, Lines 19-20

[391] 2020 PG&E RAMP Application, Chapter 4, Table 4-1, Line 13

Bow Tie

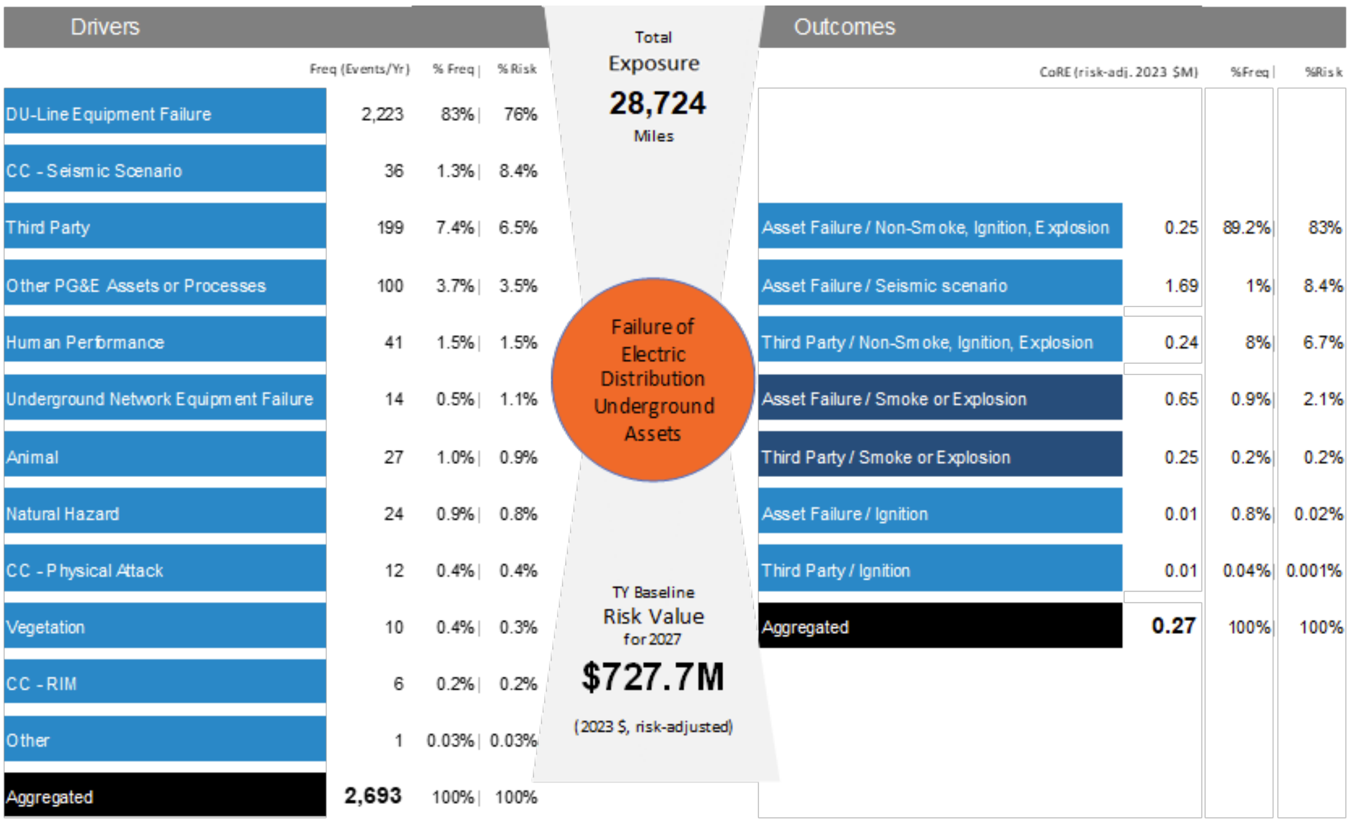

Figure 10-1: Risk Bow Tie

Observations:

At 83 percent, line equipment failure accounts for most asset failure events and most of the risk. At 89 percent, most asset failure outcomes are relatively benign, with no smoke, ignition, or explosion. Catastrophic events involving smoke or explosion account for approximately 1.1 percent of total outcome frequencies and 2.3 percent of the total risk.

Exposure

The exposure for this risk consists of the 28,724 miles of underground electric distribution cables.

Observations:

According to the risk bow tie[392] for the Failure of Distribution Network Assets risk presented in the PG&E 2020 RAMP, 188 miles of underground distribution network circuits were in the Oakland and San Francisco areas in 2020. Although PG&E did not state the miles of network circuits in the 2024 RAMP, the same 188 miles is likely an accurate estimate for 2024. This means the remaining 28,536 miles of the total exposure are radial circuits.

Due to the different population densities between regions served by network and radial underground distribution circuits, their risk profiles are different. Outages in high population density regions served by network circuits can incur more severe reliability consequences per-circuit-mile exposure than those served by non-network, radial underground circuits. Likewise, on a per-circuit-mile basis, the potential safety consequences of underground electric network asset failures in the high-density downtown regions of Oakland and San Francisco can be much more severe than in less populated areas served by radial underground distribution circuits.

Tranches

PG&E constructed tranches for this risk based on four dimensions. Within each dimension, there are two or more possible categories:

1. Radial vs. Network System ----------- 2 possible categories
2. Asset Health Need --------------------- 3 possible categories
3. Overloading Condition ---------------- 2 possible categories
4. Historical Likelihood of Failure ------ 4 possible categories

The total possible number of tranches is based on the total possible number of combinations of all categories over these four dimensions. Using this method, there are 48 (i.e., 2 x 3 x 2 x 4 = 48) possible tranche combinations. However, some combinations have no known circuit miles within PG&E's system. Given the current state and health of PG&E's system, only 24 of the 48 tranches contain non-zero circuit-miles. Figure 10-2 shows the risk per exposure unit and tranche-level risk for each of the 24 tranches.

[392] 2020 PG&E RAMP Application, Chapter 12, Page 12-5, Figure 12-1

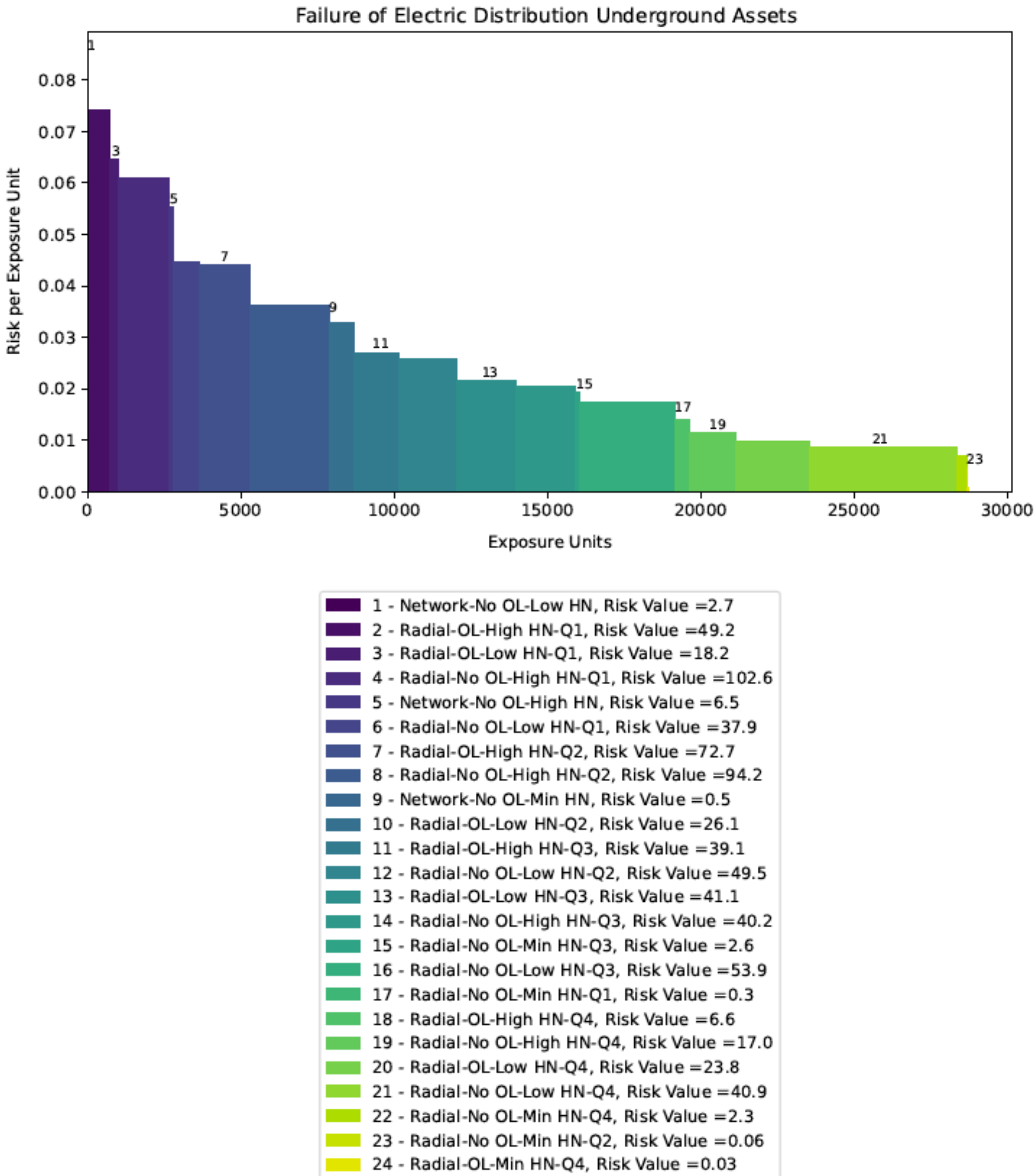

Figure 10-2: Tranche-Level Risk per Exposure Unit[393]

[393] PG&E 2024 RAMP, PG&E-2, RM-RMCBR-18 Risk per Exposure VS Exposure graphs.pdf workpaper, Page 7

Observations:

The multi-dimensional, multi-category approach to creating tranches is reasonable. Grouping assets with similar characteristics into tranches facilitates the planning and execution of mitigation options.

Given the discrete nature of some underground assets (e.g., some circuit miles may contain more high-risk and high-value discrete assets, such as transformers, than other circuit miles), a homogenous risk profile within each tranche[394] may not always be feasible. Despite this limitation imposed by the discrete nature of some underground assets, the multi-dimensional, multi-category tranche methodology provides sufficiently granular tranches in which all circuit miles within each tranche are expected to have a similar, though not always the ideal homogeneous, risk profile.

Risk Drivers

Twelve risk drivers, listed as D1 to D12, are shown in the risk Bow Tie. The only cross-cutting drivers listed are Seismic, Physical Attack, and Records and Information Management (RIM).

D1 is the DU Line Equipment Failure risk driver and "accounts for failure events due to the UG assets, including transformer, primary cable, primary splice, secondary cable failure, or other equipment."[395] D1 accounts for 83 percent of the risk event frequencies and 76 percent of the risk.

D3, the Third-Party risk driver, captures risk events, including dig-ins, caused by third parties. The safety consequences of dig-ins caused by third parties are considered within the Public Contact with Intact Energized Electrical Equipment (PCEEE) risk chapter.

Observations:

PG&E's description of the D1 driver is virtually synonymous with the risk event itself and the very name of the risk captured by the risk bow tie. Listing the risk event itself (or a very close analog) as a driver of the risk event is not particularly useful for visualizing the risk, as doing so amounts to making the tautological statement that "*The leading cause of line failures are line failures.*" It is a self-evidently true statement, but not much useful insight can be gained from it.

SPD recommends that the oversized D1 risk driver be broken into finer gradations based on equipment types, such as primary cable failure, transformer failure, primary splice failure, secondary cable failure, and other equipment failure. This would allow for a more meaningful graphical presentation of the risk analysis and possibly allow risk evaluators to gain additional insights.

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394 Step 3, Row 14 of the RDF implicitly requires a homogeneous risk profile within each tranche.

395 PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 5, page 5-10, lines 5 - 7

Cross-cutting factors

PG&E considered all seven cross-cutting factors and their individual effects on the likelihood and consequences over the 2027 to 2030 GRC period. All seven cross-cutting factors impact the risk likelihood during the GRC period. On the other hand, the climate change and RIM cross-cutting factors do not have impacts on the consequence side of the risk, but the other five cross-cutting factors do.

Observations: None

Consequences

PG&E categorizes the consequences for this risk based on whether the risk event was caused by asset failure, third-party damage, or seismic activity. The consequences of asset failure and third-party damage are further categorized by whether the failure event resulted in smoke/ignition/explosion or non-smoke/non-ignition/non-explosion. As the risk Bow Tie diagram shows, this categorization scheme results in seven possible consequence categories.

Observations: This categorization scheme clearly shows the relative amounts of risk event consequences caused by asset failure, third-party damage, and seismic activity.

Climate Adaptation Vulnerability Assessment (CAVA)

PG&E's CAVA study considered all electric distribution assets and did not separately assess underground and above-ground assets. It addresses actual or expected climatic impacts on all electric distribution assets, focusing on the 2050 decadal period. "PG&E's CAVA found that electric distribution's current mitigations and controls result in high adaptive capacity to address climate risks associated with wildfires and drought-driven subsidence and moderate adaptive capacity to address climate risks from flooding/precipitation, sea level rise, and extreme temperatures."[396]

Observations: None

Controls and Mitigations

PG&E's 2024 RAMP contains ten controls and three mitigations for the 2027 to 2030 GRC period. Figure 10-3 shows the ten controls and their CBR values. Figure 10-4 shows the three mitigation programs and their CBR values.

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[396] PG&E 2024 RAMP Report, Exhibit PG&E-4, Chapter 5, page 5-13, lines 10 - 14

CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV) [(b)]			
Line No.	Control ID [(a)]	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[(c)] [C]/([A]+[B])
1	DUNGD-C002	UG Notifications	$9,244	$9,244	$9,244	$9,244	$25.6	$6.7	$208.4	6.5
2	DUNGD-C003	UG General Equipment Maintenance and Replacement	27,521	27,521	27,521	27,521	105.7	50.5	275.3	1.8
3	DUNGD-C006	Primary Cable Replacement Program	17,680	29,945	29,679	42,136	112.3	–	92.8	0.8
4	DUNGD-C007	LBOR Switch Replacement	12,357	12,604	12,856	13,113	48.8	–	44.1	0.9
5	DUNGD-C011	Network Cable Replacement	258	2,733	4,550	8,706	14.4	17.2	34.6	1.1
6	DUNGD-C012	Network Maintenance and Corrective Work [Transformer Maintenance and Testing]	1,541	1,541	1,541	1,541	4.3	–	21.8	5.1
7	DUNGD-C014	Network Component (Transformer, Protector) Replacements - Condition Based [Transformer]	1,037	1,037	1,124	1,168	4.2	5.9	8.0	0.8
8	DUNGD-C015	Network Component (Transformer, Protector) Replacements - Condition Based [Protector]	111	111	121	126	0.4	0.6	0.1	0.1
9	DUNGD-C016, PCEEE-C001, LOCDM-C017	Locate and Mark – Distribution	85,971	84,252	82,567	80,916	231.1	8.5	113.3	0.5
10	DOVHD-C024, DUNGD-C017, PCEEE-C002	Public Safety Awareness	1,588	1,588	1,588	1,588	4.4	–	33.6	7.6
11	Total		$157,308	$170,576	$170,792	$186,058				

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
(c) CBR calculations include allocated Foundational Activity Program costs.
Note: For additional details see Exhibit (PG&E-4), WP EO-DUNGD-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

(PG&E-4)

Figure 10-3: Controls, Cost Estimates, and CBR[397]

397 PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 5, Table 5-11, page 5-31

MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]				
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[b] [C]/([A]+[B])	Factors Affecting Selection
1	DUNGD-M006	Network Component Replacements – High-Rise Dry-Type Transformers [Transformer]	$903	$903	$903	$903	$3.5	–	$1.2	0.3	Risk Tolerance, Modeling Limitations
2	DUNGD-M007	Network Component Replacements – High-Rise Dry-Type Transformers [Protector]	97	97	97	97	0.4	–	1.2	3.2	
3	DUNGD-M008	Network Component Replacements – Targeted Network Protector Replacement CMD-Type	146	146	49	–	0.3	–	0.0	0.1	Operational and Execution Concerns
4	Total		$1,146	$1,146	$1,049	$1,000					

(a) NPV uses a base year of 2023.
(b) CBR calculations include allocated Foundational Activity Program costs.
Note: For additional details see Exhibit (PG&E-4), WP EO-DUNGD-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

Figure 10-4: Mitigation Cost Estimates and CBR[398]

Observations:

To determine whether it would be possible to narrow the scope of some control and mitigation programs with low CBR values to concentrate the activities on tranches with higher CBR values, SPD examined the tranche-level CBRs for these programs. The programs listed below are the comprehensive list of all controls and mitigations for which PG&E is seeking funding in the 2027 through 2030 GRC period. SPD located tranche-level CBRs over the 2027-2030 period for these programs in the file named RM-RMCBR-20 "*Tranche-level CBR VS NPV of Program Costs graphs.pdf*":

DUNGD-C002
DUNGD-C003
DUNGD-C006
DUNGD-C007
DUNGD-C011
DUNGD-C012
DUNGD-C014
DUNGD-C015
DUNGD-C016

[398] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 5, Table 5-13, page 5-33

DUNGD-C017
DUNGD-M006
DUNGD-M007
DUNGD-M008

Of particular interest are the five control programs, DUNGD-C006, DUNGD-C007, DUNGD-C014, DUNGD-C015, and DUNGD-C016, and the two mitigation programs DUNGD-M006 and DUNGD-M008, all of which have a CBR value less than 1.0. These programs present an opportunity for ratepayer cost savings by limiting risk mitigation activities to tranches where the CBR values are greater than or equal to 1.0.

DUNGD-C006: Figure 10-5 below shows the diminishing CBR characteristic of DUNGD-C006 with only Tranches 1, 2, and 3 having a CBR of at least 1.0. From a purely cost-benefit analysis perspective without other considerations, primary cable replacement work in the DUNGD-C006 control program should only be performed on the top three riskiest tranches shown in Figure 10-5. Figure 10-5 does not capture possible non-CBR justifications for expanding mitigation work to tranches below the CBR=1.0 threshold. Such justifications could conceivably include, for example, risk tolerance, minimum asset replacement rate considering the age and expected remaining life expectancy of the assets, contractual obligations, the desire to achieve a lower unit cost with a higher volume of work, possible compliance requirements, concurrent mitigation work with other mitigation activities, and others. However, PG&E presented no such justifications.

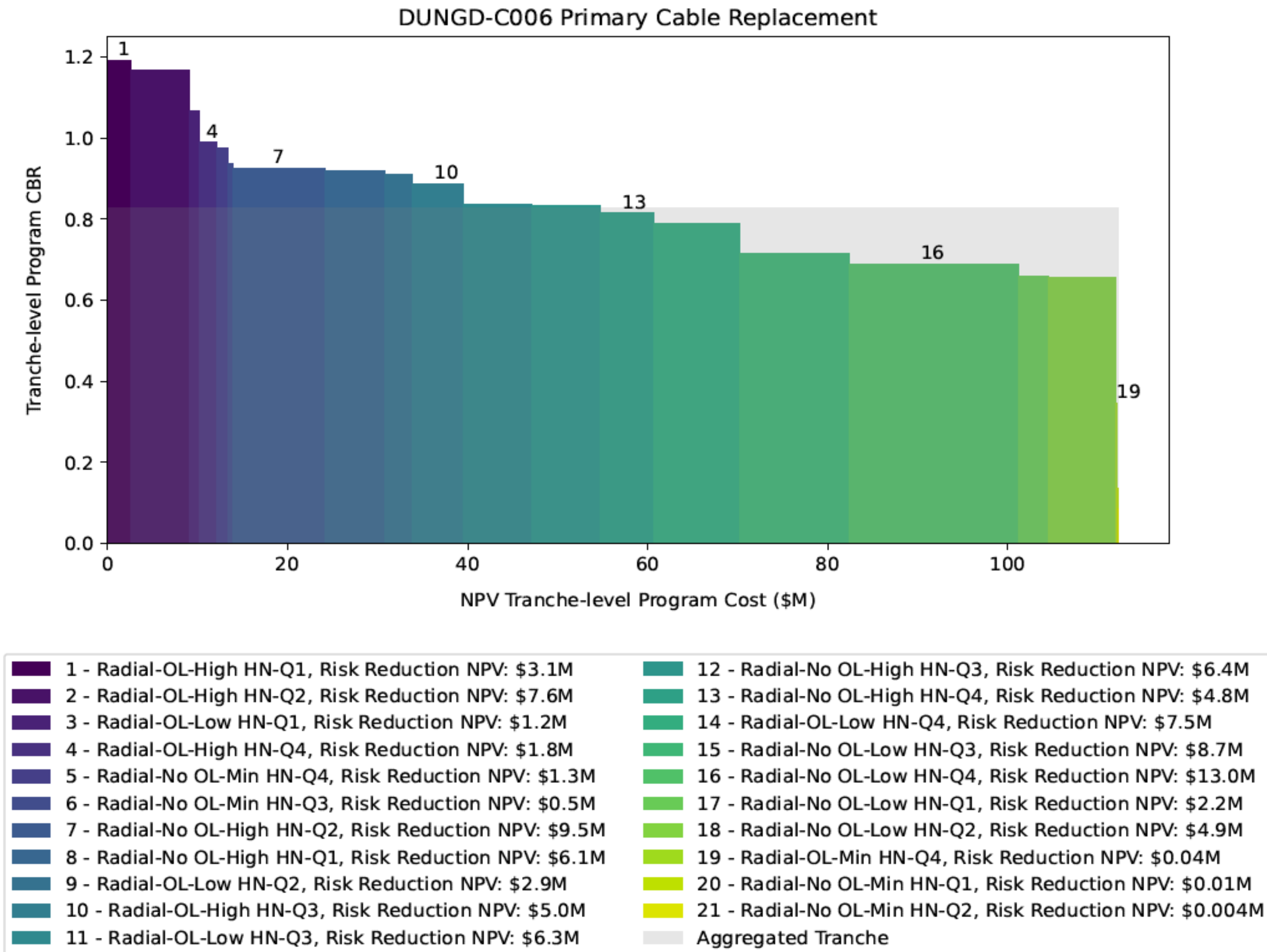

Figure 10-5: Tranche-level CBR Values for DUNGD-C006 Primary Cable Replacement[399]

DUNGD-C007: For the DUNGD-C007 LBOR (Transformer Load-Break) Switch Replacement control program, Figure 10-6 shows the tranche-level CBR values. Figure 10-6 shows that only the top 9 riskiest tranches in this control program have a CBR greater than or equal to 1.0. From a cost-benefit perspective, LBOR switch replacement work should only be performed on the top 9 riskiest tranches. Again, Figure 10-6 does not capture possible non-CBR justifications for performing LBOR switch replacement work for tranches with a CBR less than 1.0.

[399] PG&E 2024 RAMP, Exhibit PG&E-2 workpaper, RM-RMCBR-20 Tranche-level CBR VS NPV of Program Costs graphs.pdf, page 89

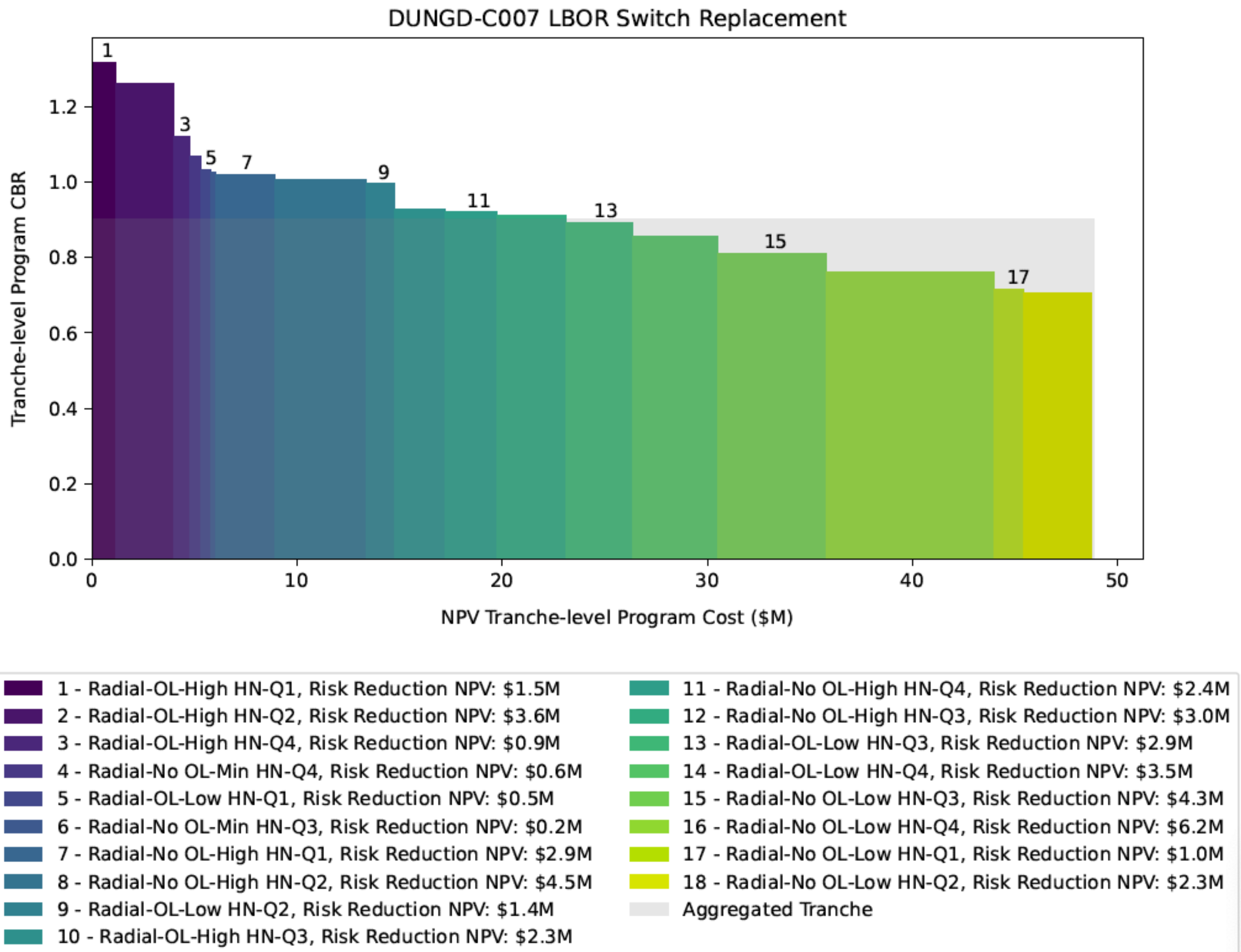

Figure 10-6: Tranche-level CBR Values for DUNGD-C007 LBOR Switch Replacement[400]

DUNGD-C014: Figure 10-7 shows the tranche-level CBR values for the DUNGD-C014 control program, an asset condition-based transformer replacement program covering the Oakland/San Francisco downtown network systems. The program CBR is 0.8, and there is no tranche in which the CBR is above 0.8. The CBR of 0.8 calls into question whether this control program should be funded for the 2027 to 2030 GRC period at all. PG&E states that transformers are usually replaced (in DUNGD-C014) at the same time as network protectors (in DUNGD-C015). There could be other considerations and justifications that PG&E did not present in the 2024 RAMP that would justify this program despite the CBR being less than 1.0.

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[400] PG&E 2024 RAMP, Exhibit PG&E-2 workpaper, RM-RMCBR-20 Tranche-level CBR VS NPV of Program Costs graphs.pdf, page 90

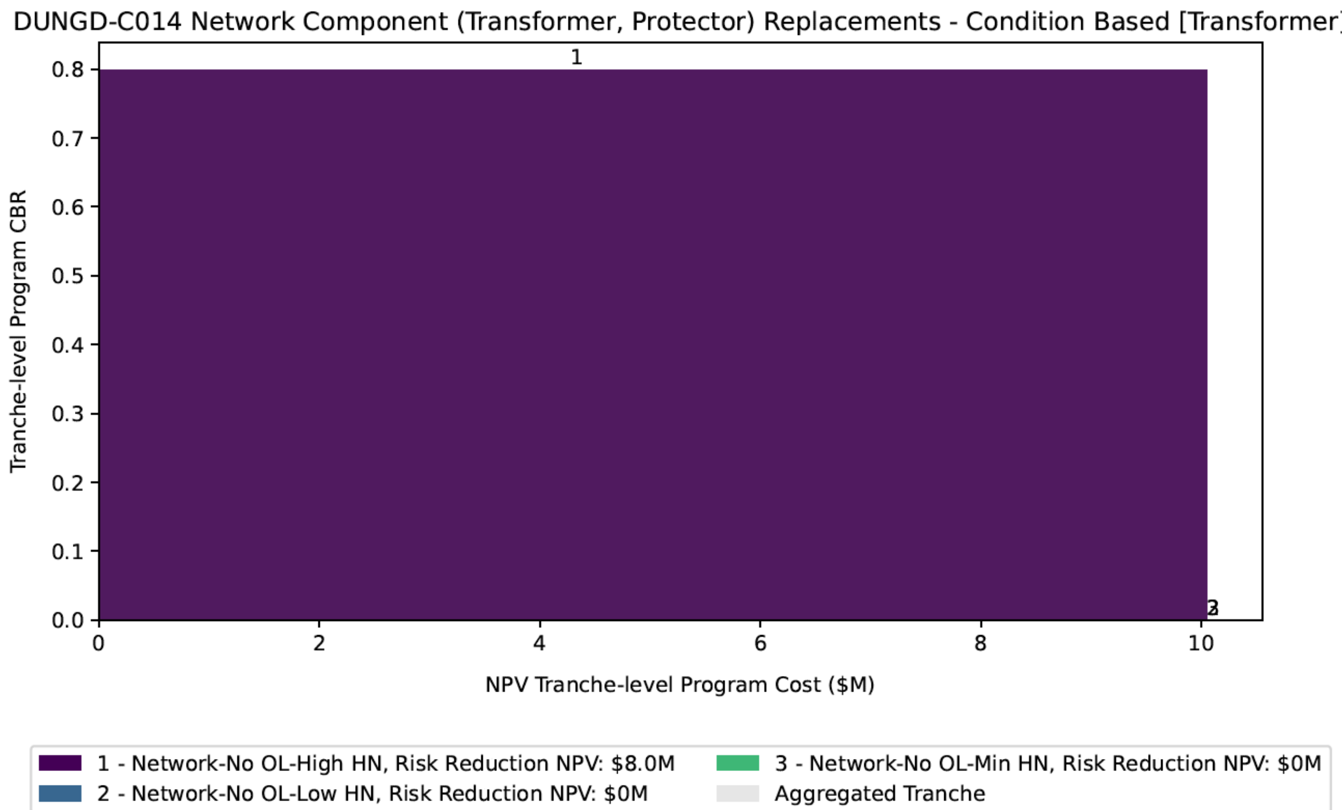

Figure 10-7: Tranche-level CBR Values for DUNGD-C014[401]

DUNGD-C015: Figure 10-8 shows the tranche-level CBR values for the DUNGD-C015 control program, an asset condition-based replacement program of network protectors in the Oakland/San Francisco downtown network systems. The description for DUNGD-C015 states that "this control addresses potential transformer or protector failures. It reduces the UG Network Equipment Failure driver, which includes reducing the consequence of an explosion, smoke, or fire event." [402] Based on this description, DUNGD-C015 is not a compliance-based (i.e., mandatory) activity. It has an aggregate CBR of 0.1. PG&E states that network protectors (in DUNGD-C015) are usually replaced at the same time as transformers (in DUNGD-C014). Since both DUNGD-C014 and DUNGD-C015 have a CBR less than 1.0 at the program level and at any tranche level, it calls into whether additional justification is needed to warrant their funding

[401] PG&E 2024 RAMP, Exhibit PG&E-2 workpaper, RM-RMCBR-20 Tranche-level CBR VS NPV of Program Costs graphs.pdf, Page 82

[402] PG&E 2024 RAMP, PG&E-4, Chapter 5, page 5-24, lines 10 - 18

in the 2027 to 2030 GRC period. As controls, both programs are continuations of existing programs. However, that does not mean they should be automatically approved for continued funding in the 2027 to 2030 GRC period, regardless of their low CBRs. Once again, there could be other considerations that PG&E did not present, which could justify their continued funding for 2027 to 2030. PG&E should provide additional information and/or additional justifications for these two controls in the GRC application.

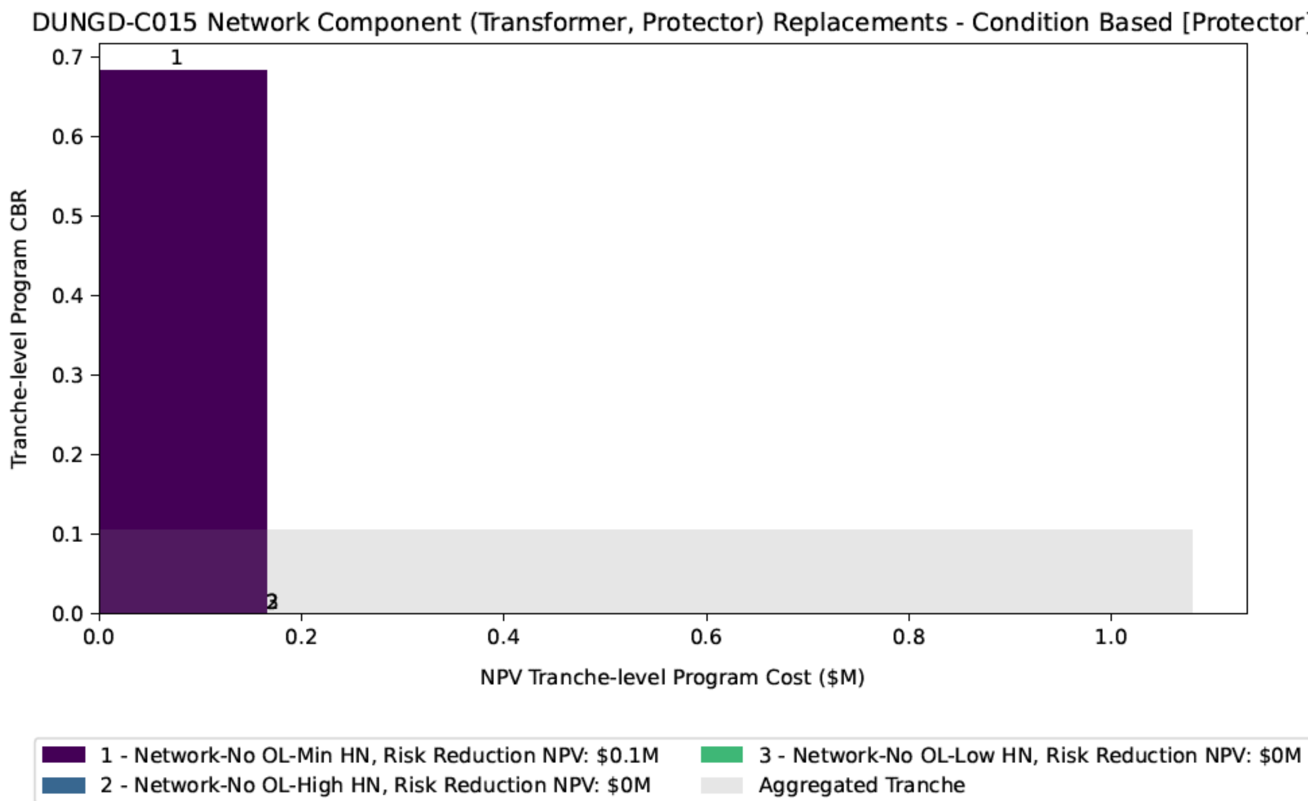

Figure 10-8: Tranche-level CBR Values for DUNGD-C015[403]

DUNGD-C016: For DUNGD-C016, the low CBR is irrelevant since it is the compliance-related Locate and Mark program.

DUNGD-M006: PG&E describes the DUNGD-M006 program as:

[403] PG&E 2024 RAMP, Exhibit PG&E-2 workpaper, RM-RMCBR-20 Tranche-level CBR VS NPV of Program Costs graphs.pdf, page 83

> **"Network Component Replacements – High-Rise Dry-Type Transformers [Transformer]:** PG&E plans to replace older dry type transformers in high-rise buildings. A total of 22 of these older dry type transformers have been identified, with most installed in the 1980s. These units are at, or nearing, the end of their useful lives and experience asset health concerns, including rust and other corrosion. This mitigation reduces the UG Network Equipment Failure driver, which includes reducing the consequence of an explosion, smoke, or fire event." [404]

From the mitigation description given above, DUNGA-M006 is not a compliance-related activity. Figure 10-4 shows the program has a CBR of 0.3. PG&E cites "risk tolerance" in Figure 10-4 as a justification for this using this mitigation. However, as SPD learned from PG&E's response to data request SPD-PGE-2024RAMP-021, Question 1, asking whether PG&E has a numeric risk tolerance value, to which PG&E responded that PG&E "... *currently has not formalized a methodology for quantitative risk tolerance values.*" A generic citation of "risk tolerance" without a way to quantify the tolerance is insufficient. [405]

PG&E did not include any data in the 2024 RAMP workpapers regarding the expected remaining life of these transformers or the likelihood of their failure in the next few years. SPD recommends that to justify the funding of this mitigation, PG&E should provide data or analysis on the age, expected remaining life, and the likelihood of failure before 2031 for each of the 22 transformers if they were not replaced before 2027. SPD recommends that PG&E should provide these types of data and/or analysis and to include them with the Test Year 2027 GRC workpapers.

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[404] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 5, page 5-26

[405] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 5, page 5-34, lines 21 - 22

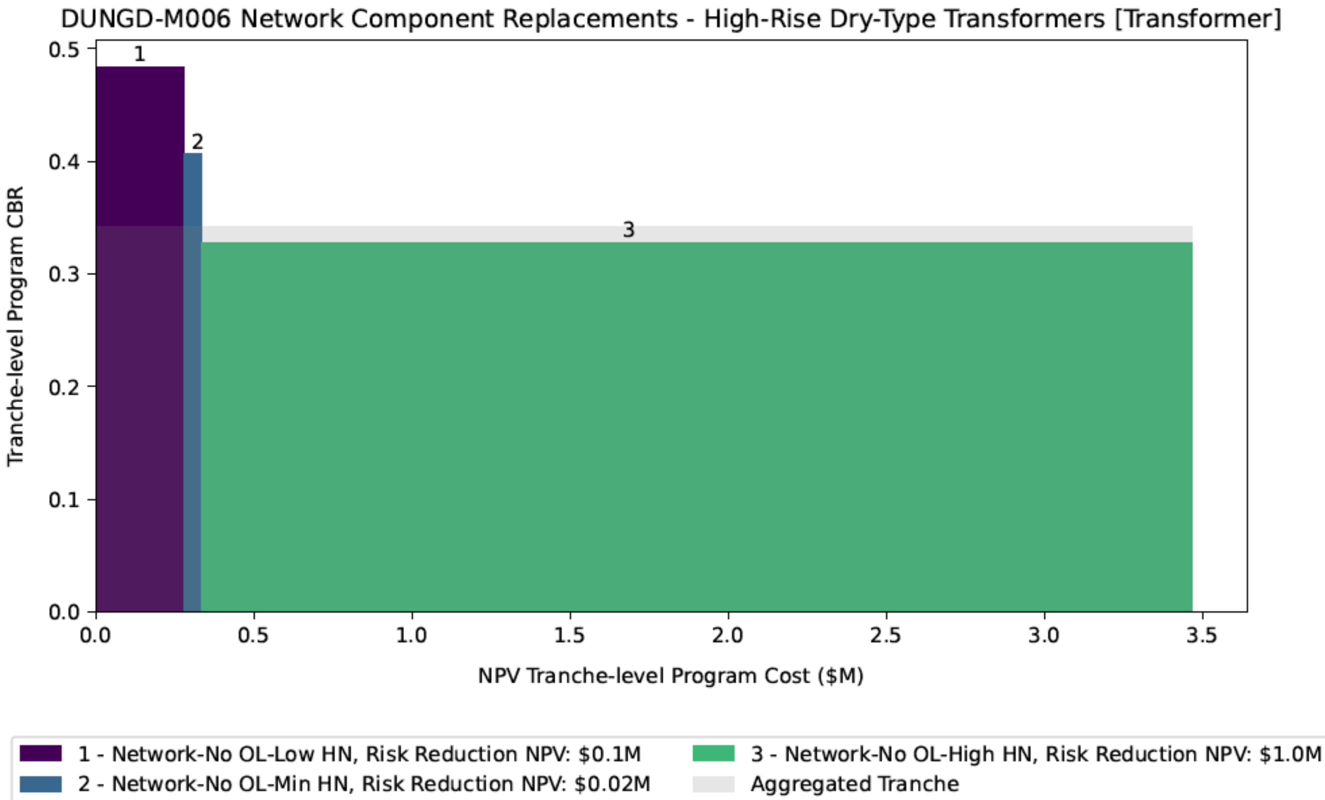

Figure 10-9: Tranche-level CBR Values for DUNGD-M006[406]

DUNGD-M008: PG&E describes this mitigation program as:

> **"Network Component Replacements – Targeted Network Protector Replacement CMD-Type:** Based on service records, PG&E has concluded that CMD network protectors are more difficult to repair and replace, as they are an older style and have obsolete components. This program aims to replace targeted CMD units in the PG&E network with more reliable network protector models to increase system resilience and to reduce potential outage duration due to repair difficulty. It also reduces the UG Network Equipment Failure driver, which includes reducing the consequence of an explosion, smoke, or fire event."[407]

The CBR values for DUNGD-M008 are shown in Figure 10-10. From PG&E's description of this mitigation program, it is not a compliance-related activity. The CBR for the program is around 0.12, and no

[406] PG&E 2024 RAMP, Exhibit PG&E-2 workpaper, RM-RMCBR-20 Tranche-level CBR VS NPV of Program Costs graphs.pdf, page 79

[407] PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 5, pp. 26 - 27

tranche has a CBR greater than 0.25 under this program. Again, these low CBR numbers call into question whether PG&E should implement this mitigation program without providing additional details.

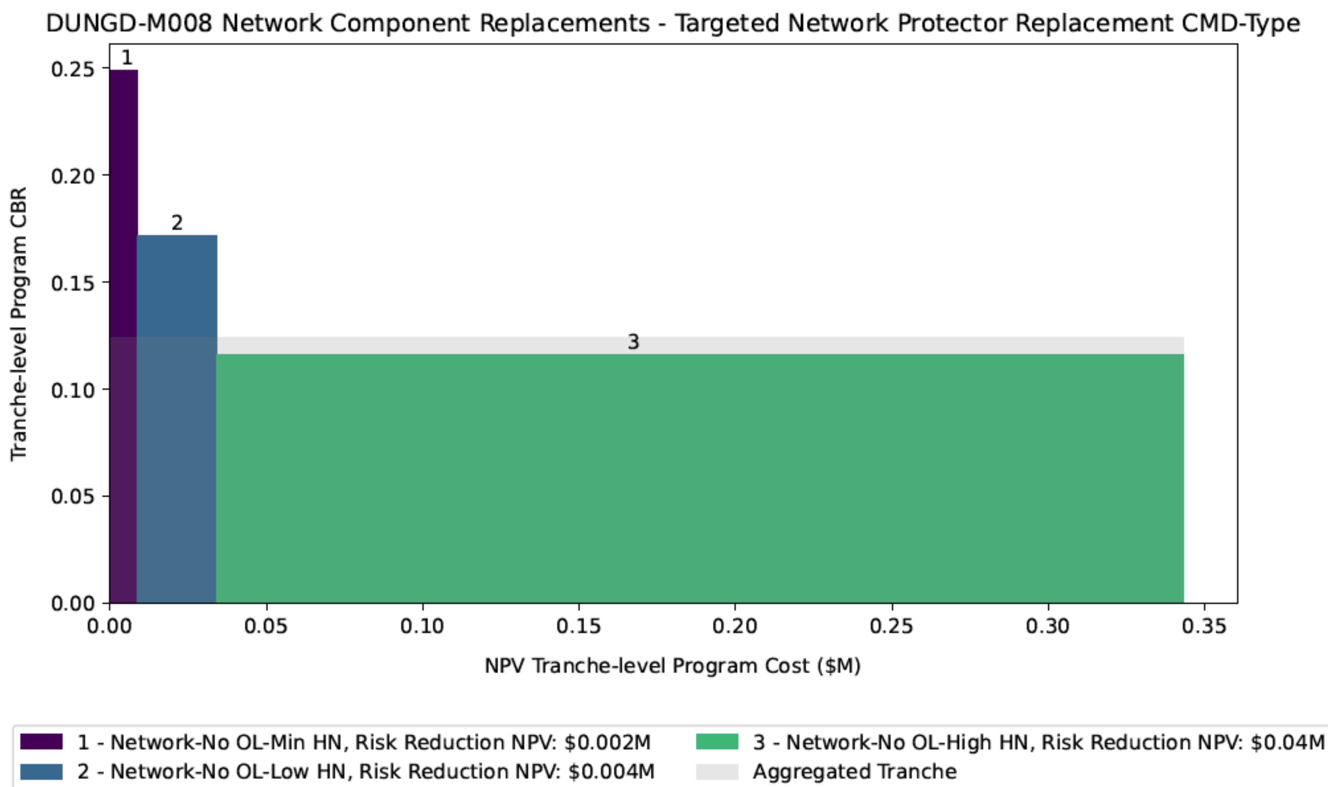

Figure 10-10: Tranche-level CBR Values for DUNGD-M008[408]

Alternatives Analysis

PG&E considered two alternative mitigations, which PG&E refers to as "Alternative Plans."

Alternative Plan 1 (DUNGD-A001) – Venting Manhole Cover Replacements involves replacing approximately 4,000 non-venting manhole covers with venting types. This alternative mitigation has a program cost of $4.6 million and a CBR of 0.3 over the 2027 to 2030 GRC period.

Alternative Plan 2 (DUNGD-A002) – Radial Deteriorated Concentric Neutrals involves replacing unjacketed primary distribution cables in the PG&E system within 20 years. These unjacketed cables comprise most cable failures in PG&E's underground distribution system. These cables have either

[408] PG&E 2024 RAMP, Exhibit PG&E-2 workpaper, RM-RMCBR-20 Tranche-level CBR VS NPV of Program Costs graphs.pdf, page 81

exceeded or are close to their 40-year average expected life. This alternative mitigation has a program cost of $1.146 billion and a CBR of less than 0.1 over the 2027 to 2030 GRC period.

Observations:

Using the numbers provided in Figures 10-3 and 10-4, SPD prepared Table 10-2, which shows the total program costs and aggregate CBR of the Primary Plan being proposed by PG&E. The costs and CBRs are shown with and without the Locate and Mark compliance-related activity to make comparing the Proposed Plan with the Alternative Plans more meaningful.

As Table 10-2 shows, the CBR of both Alternative Plans is significantly less than the 2.22 CBR of the Proposed Plan without Locate and Mark or the 1.5 CBR with Locate and Mark. Neither alternative plan is a realistic competitive alternative to the Proposed Plan.

Table 10-2: CBR Comparison between Proposed Plan and Alternative Plans

	(1)	**(2)**	**(3)**
	Total Costs ($ millions)	**Total Monetized Risk Reduction ($ millions)**	**CBR (2)/(1)**
Controls, w/o Locate & Mark	320.1	718.7	2.25
Control, with Locate & Mark	551.2	832.0	1.51
Mitigations	4.341	2.4	0.55
Total Proposed Plan, w/o Locate & Mark	324.441	721.1	2.22
Total Proposed Plan, with Locate & Mark	555.541	834.4	1.50
DUNGD-A001	4.6	1.2	0.3
DUNGD-A002	1,146.3	30.3	0.026

CBR Calculations

Observations: SPD has no critical observations on how CBRs are calculated or presented in this risk chapter. SPD finds the graphical tranche-level CBR value presentation in the *RM-RMCBR-20 Tranche-level*

CBR VS NPV of Program Costs graphs.pdf file very useful and would like to see PG&E continue to include this type of graphical presentation in future RAMPs.

Summary of Findings

1. Consolidating all underground electric distribution assets into one risk ensures that all underground distribution assets fall within the purview of a RAMP risk.
2. Data sources for this risk appear to be either wholly or mostly lagging data.
3. The highly discrete nature of some underground assets makes a homogenous risk profile within each tranche not always feasible.
4. The D1 driver is virtually synonymous with the risk event itself and the very name of the risk captured by the risk bow tie. Listing the risk event itself (or a very close analog) as a driver of the risk event is not particularly useful for visualizing the risk.
5. Five control programs, DUNGD-C006, DUNGD-C007, DUNGD-C014, DUNGD-C015, and DUNGD-C016, and the two mitigation programs DUNGD-M006 and DUNGD-M008 have a CBR value less than 1. They present an opportunity for ratepayer cost savings by limiting risk mitigation activities to tranches where the CBR values are greater than or equal to 1.
6. PG&E did not identify which controls are compliance-related, making interpretation of the low CBRs challenging.
7. For the DUNGD-M006 program, PG&E did not include any data in the 2024 RAMP workpapers regarding the expected remaining life of the transformers or the likelihood of their failure in the next few years.
8. Due to the low CBR, DUNGD-M008, should provide additional information to justify its implementation in the 2027 to 2030 GRC funding period.
9. Existing mitigations (i.e., controls) with low CBRs should not be automatically approved for continued funding.
10. The graphical tranche-level CBR presentations are a valuable tool for analyzing the cost-effectiveness of risk mitigations. PG&E should continue to include these diagrams in future RAMP and GRC workpapers.
11. The Alternative Plans presented by PG&E are not realistic alternatives to the Proposed Plan because of the low CBRs.

Recommended solutions to address findings and deficiencies

1. SPD recommends that PG&E incorporate (more) leading indicator data into the data quantification sources.
2. SPD recommends that the oversized D1 risk driver be broken into finer gradations based on equipment types, such as primary cable failure, transformer failure, primary splice failure, secondary cable failure, and other equipment failure. This would allow for a more meaningful graphical presentation of the risk analysis.

3. SPD recommends that to the maximum extent practicable, PG&E should apply each risk mitigation program only to those tranches with a CBR of at least 1, while recognizing there may be valid considerations to deviate from this recommendation.
4. SPD recommends that PG&E must identify all compliance-related control programs.
5. SPD recommends that PG&E to justify the DUNGD-M006 program by providing data or analysis on the age, expected remaining life, and the likelihood of failure before 2031 for each of the 22 transformers if they were not replaced before 2027. This data and/or analysis using the data should be included with the Test Year 2027 GRC workpapers.
6. SPD recommends that PG&E must provide more adequate justification for funding the DUNGD-M008 program in the Test Year 2027 GRC.
7. SPD recommends that controls with low CBRs should not be automatically approved for continued funding. They should be re-justified with each new RAMP and GRC based on their new CBRs and other considerations.
8. PG&E should present alternative, more realistic and competitive mitigation plans than the proposed one.

11. Loss of Containment on Gas Distribution Main or Service

Risk Description

This chapter focuses on Loss of Containment on Gas Distribution Main or Service (LOCDM) risk associated with Pacific Gas and Electric's (PG&E) gas distribution system. The primary concern with a Loss of Containment (LOC) event is the potential for the leak to migrate and/or ignite.

Of the 32 Corporate Registered Risks listed in PG&E's 2027 Test Year analysis, LOC on distribution mains and services are the twelfth-highest baseline total risk value ($106.7 million) and the eleventh-lowest baseline safety risk value ($19.0 million).[409] This places LOCDM baseline risk values near the bottom of the twelve risks presented in PG&E's 2024 RAMP Report.

Table 11-1. Risk Definition and Scope[410]

LOSS OF CONTAINMENT ON GAS DISTRIBUTION MAIN OR SERVICE	
Definition	Failure of a gas distribution main or service resulting in a LOC, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas (NG) to customers.
In Scope	Failure of a distribution pipeline that leads to a minor or major LOC.
Out of Scope	A LOC driven by large over pressure events and customer-connected equipment.
Data Quantification Sources	RiskFinder likelihood of failure estimates, Pipeline and Hazardous Materials Safety Administration (PHMSA) Reportable Incident Data, Legacy Cross Bore program inspection data, PG&E's 2023 General Rate Case (GRC) application, PG&E Gas Distribution Geographic Information System, PG&E gas distribution leak data, PG&E Customer Outage Data, 2020 United States census block data, PG&E unit cost information from its 2023 GRC.

[409] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-2, lines 13-16.
[410] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-3.

Observations:

PG&E continues the practice established in its 2020 RAMP Report of including LOC events without ignition in its definition of LOCDM risks.[411] PG&E contends this practice allows it to utilize more company-specific data, rather than rely on industry data from other utilities.[412] Safety Policy Division (SPD) observes an analysis that includes LOCs without ignition, a common event in gas distribution systems, will result in significantly higher frequency values. SPD expects that the inclusion of LOCs without ignition results in a significantly lower average Consequence of Risk Event (CoRE) value, as LOC events where no ignition occurs rarely result in injury or property damage. Given these considerations, SPD observes that inclusion of non-ignition LOCs effectively transforms the LOCDM risk chapter from a low frequency/high average consequence risk to a high frequency/low average consequence risk.

Additionally, SPD is concerned with the lack of clarity in the definition of risk, specifically in determining which distribution-level LOC events are included in the risk analysis. SPD observes that in its 2023 annual report of system-wide leaks associated with the "Natural Gas Leak Abatement Program" (NGLA) established through Rulemaking (R.)15-01-008, PG&E identified approximately 280,000 leaks in its meter set assemblies and over 20,000 leaks in distribution pipelines.[413] This is a significantly higher total of distribution-level leaks (LOC) than the 28,726 LOCDM events stated by PG&E in its 2024 RAMP filing (PG&E 3, Chapter 2). In its risk definition, PG&E states risk analysis includes failures of gas distribution mains and services "that can lead to significant impact." While SPD agrees that not every leak should be included in the risk analysis, it is unclear what criteria PG&E applied when determining which non-ignition LOC events are categorized as having "significant impact" given the high frequency and low consequence of most non-ignition LOC events. SPD recommends PG&E provide more clarity in its 2027 GRC Application of how it determines which non-ignition LOC distribution events qualify, and not qualify, for consideration.

Bow Tie

PG&E presents critical information on the risk analysis of the drivers and outcomes of the LOCDM risk in its Bow Tie model.

411 PG&E 2020 RAMP, Chapter 8, page 8-8, lines 3-6.
412 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-6, lines 5-9.
413 PG&E 2024 Natural Gas Leak Abatement Report (for year 2023), Appendix 8, https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R1501008/7548/533676514.pdf.

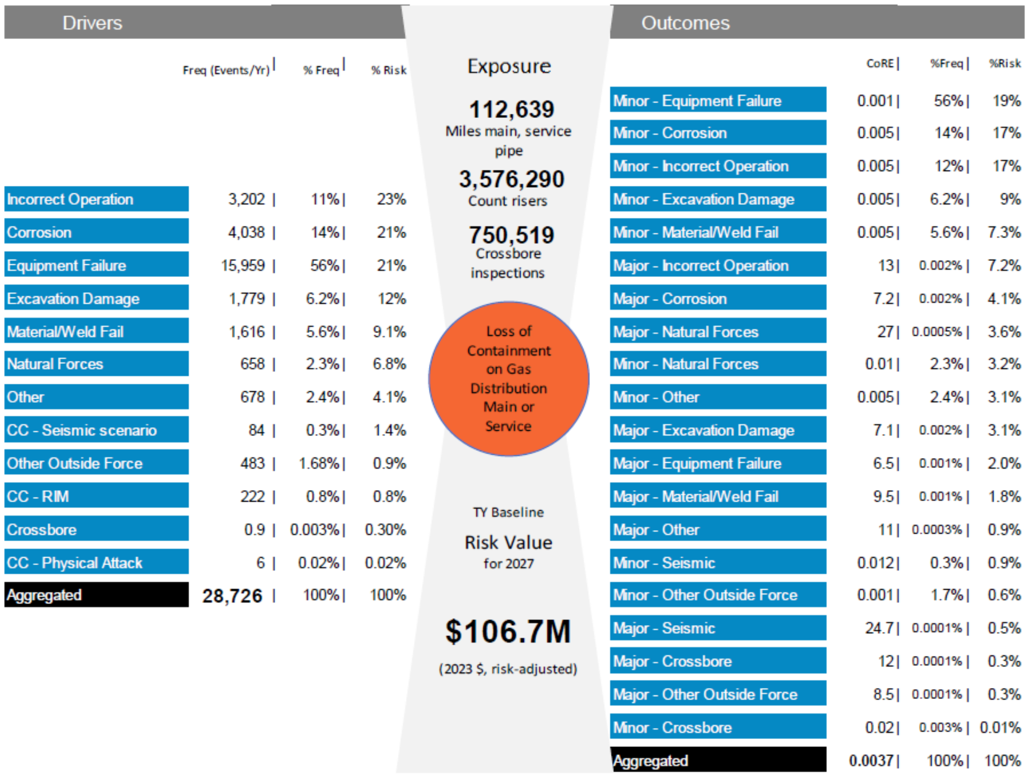

Figure 11-1. Risk Bow Tie[414]

Observations:

In its 2024 RAMP Risk Bow Tie for LOCDM, PG&E makes only minor changes from that shown in its 2020 RAMP. The drivers are all the same in both, except for the removal of the cross-cutting driver "Skilled and Qualified Workforce."[415] In its 2020 RAMP report PG&E began to report cross-bore pipes[416] within the LOCDM risk chapter, as opposed to a separate chapter in 2017.[417]

Exposure

As shown in Figure 11-1, PG&E approximates 112,639 miles of distribution pipeline, 3,567,290 gas risers, and 750,519 cross-bore inspections as its exposure for the LOCDM risk.

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414 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-6.
415 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-6, lines 10-12.
416 Cross-bore pipe is pipe that intersects with other existing utility infrastructure, typically sewage lines.
417 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-6, lines 3-4.

Observations:

PG&E estimates the number of gas risers in its distribution system by assuming one gas riser for every service.[418] SPD notes this assumption likely results in an overestimation of the number of gas risers in the system, as risers frequently feed multiple services, such as in multi-family housing complexes. SPD expects the impact of such an overestimation is more pronounced in higher-density areas.

Tranches

PG&E grouped assets with similar classifications into tranches, resulting in 42 total tranches being identified in the LOCDM chapter of its 2024 RAMP report. Each component is classified by asset type (i.e., service, main, or riser), material (i.e., steel or plastic), age (older or newer than a specified year - 1941 for steel, 1985 for plastic), population density (high or low), whether asset is indoor or outdoor (if asset is a riser), and whether asset was recommended for the Distribution Integrity Management Program (DIMP) Mitigation Analysis (MA), if the asset is a main.[419] For example, one tranche is labeled "Main – Steel Installed < 1941 – Population Density High – MA Yes." Forty of these tranches are based on asset type. An additional two tranches specifically relate to cross-bore location (occurring in San Francisco or not in San Francisco).[420]

Observations:

PG&E has significantly increased the number of tranches from the 12 presented in the 2020 RAMP Report by further classifying assets by asset vintage, whether a main is recommended for DIMP MA, and whether a riser is located indoors or outdoors. PG&E also addresses the possibility of further granularity by creating categories for pre-1975 plastic pipelines and pre-1924 steel pipelines, acknowledging these respectively exhibit 33 percent and 16 percent higher likelihood of failures in the 2022 DIMP operation risk model relative to their 1975-1984 plastic and 1924-1940 steel counterparts. However, PG&E argues that 1985 and 1941 represent the major demarcation time frames between the respective failure likelihoods in plastic and steel pipelines, and that further granularity is unnecessary.[421] While SPD acknowledges the improvement in granularity by tranching, additional granularity may be necessary to perform more targeted work, given the poor Cost Benefit Ratio (CBR) values for the large costs and scale of work currently proposed in mitigations LOCDM-M001 "Pipeline Replacement Program (Steel)" and LOCDM-M002 "Pipeline Replacement Program (Plastic)."

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[418] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-7, lines 3-6, footnote 4.
[419] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-7, lines 10-17.
[420] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-7, lines 17-18.
[421] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-7 to 2-8.

Risk Drivers

PG&E presents nine key risk drivers (D1 to D9)[422] in the Risk Bow Tie for LOCDM. Equipment Failure accounts for the majority of expected LOCDM events (56 percent), with Corrosion (14 percent) and Incorrect Operation (11 percent) estimated to be the next most likely drivers of the forecasted 28,726 events. These three drivers account for 65 percent of the total LOCDM risk.

Observations:

SPD observes that despite Equipment Failure being forecasted as the driver of more than half of all risk events, it accounts for only 21 percent of total LOCDM risk, suggesting this particular driver is primarily responsible for high frequency, low impact risk events.

Cross-cutting factors

Of the seven cross-cutting factors presented in its 2024 RAMP, PG&E identifies four that impact the likelihood and three that impact the consequence of an LOCDM event (Table 11-2 below). However, PG&E does not include Climate Change and Emergency Preparedness and Response in the Bow Tie or quantify in the model.

Table 11-2. Cross-Cutting Factors (CCF)[423]

CCF Name	Impacts Likelihood	Impacts Consequence
Climate Change	Yes*	No
Cyber Attack	No	No
Emergency Preparedness and Response	No	Yes*
Information Technology (IT) Asset Failure	No	No
Physical Attack	Yes	No
Records and Information Management (RIM)	Yes	Yes
Seismic	Yes	Yes
Yes	CCF has been quantified in the model.	
Yes*	CCF does influence the baseline risk but is not quantified in the model, or it may influence the baseline risk, but further study is needed.	
No	CCF does not influence the baseline risk.	

422 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, pp. 2-12 to 2-14.
423 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-16.

Observations:

As shown in the Bow Tie (Figure 11-1), the total risk presented by cross-cutting factors is relatively low. The three cross-cutting factors PG&E quantifies in the model comprise approximately 1.1 percent of likelihood and 2.2 percent of the total LOCDM risk value.

Regarding the Seismic cross-cutting factor, SPD observes that while a major seismic event is exceptionally rare (estimated at 0.0001 percent likelihood in the 2027 Test Year), PG&E estimates a CoRE value of $24.7 million per event, significantly higher than most other LOCDM event outcomes. Due to the low likelihood, major seismic events contribute relatively little to the LOCDM total risk score (approximately $0.30 million per year of the total $106.7 million per year risk score).[424] However, should a major seismic event occur, that single event could increase the total risk of LOCDM events by over 22 percent. Such discrepancies highlight the challenges associated with quantifying risk from so-called "black swan events," i.e., large earthquakes, that are extremely uncommon and difficult to predict but produce large consequences.

Consequences

In its 2024 RAMP report, PG&E classifies the outcome of a risk event based on whether it qualifies as "major" or "minor," then further separates the outcome based on the driver of the LOC event (e.g., "Major – Corrosion").

PG&E defines a major LOC event as one qualifying as a Pipeline and Hazardous Materials Safety Administration (PHMSA) "significant incident" (results in a fatality or in-patient hospitalization, or $50,000 or more in total costs - in 1984 dollars).[425] Due to the low frequency, PG&E does not have sufficient company-specific data to model safety[426] or financial[427] consequences for Major LOCDM events; instead, it uses PHSMA industry incident data (which includes PG&E data).

For minor events, PG&E calculates reliability consequences by using historic PG&E data of customer outages caused by leaks.[428] Financial consequences are calculated by estimating the cost of repairing the leak.[429]

Observations:

While PG&E provides a clear definition of what qualifies as a "major" LOCDM event, it is unclear how PG&E distinguishes between a gas distribution LOC event that is not included for consideration in the 2024 RAMP Report, and one included in the report as a "minor" LOCDM event. SPD observes this

[424] PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2 at 2-24.
[425] PHMSA, "Pipeline Incident Flagged Files", https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files.
[426] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-18, lines 7-13.
[427] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-21, lines 13-17.
[428] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-21, lines 24-29.
[429] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-22, lines 1-3.

appears related to the decision to include non-ignition LOCs in the analysis for this chapter. As shown in the Risk Bow (Figure 11-1), “minor” outcomes account for the vast majority of LOCDM frequency in PG&E’s risk analysis: over 99 percent of LOCDM events. Due to the high frequency, minor LOCDM events contribute over 75 percent of the total risk value of $106.7 million in PG&E’s risk analysis. However, as shown in Table 11-3, minor outcomes are characterized by having zero safety impact. Furthermore, SPD observes the outsized contribution of the financial attribute risk score from minor events: of the $81.4 million risk score from LOCDM events categorized as “minor,” $76.5 million is from financial consequences. These two factors, combined with the previously described high relative frequency of minor LOCDM events, results in an analysis that weighs against safety considerations and favors reducing financial impacts associated with leak repair when determining appropriate controls and mitigations.

Table 11-3. Risk Event Consequences[430]

Consequence	Attribute Risk Score (risk adjusted 2023 Millions of Dollars/Year)			Total Risk (risk adjusted 2023 Millions of Dollars/Year)
	Safety	Reliability	Financial	
Minor – Equipment Failure	-	0.73	19.17	19.90
Minor – Corrosion	-	1.00	17.41	18.41
Minor – Incorrect Operation	-	1.05	16.61	17.66
Minor – Excavation Damage	-	0.58	8.69	9.27
Minor – Material/Weld Fail	-	0.49	7.25	7.74
Major – Incorrect Operation	6.19	0.92	0.56	7.67
Major – Corrosion	2.85	1.00	0.54	4.39
Major – Natural Forces	3.45	0.24	0.12	3.81
Minor – Natural Forces	-	0.20	3.20	3.40
Minor – Other	-	0.20	3.12	3.32
Major – Excavation Damage	2.08	0.68	0.50	3.26
Major – Equipment Failure	1.24	0.64	0.21	2.09
Major – Material/ Weld Fail	1.44	0.25	0.26	1.95
Major – Other	0.78	0.13	0.10	1.01
Minor – Seismic	-	0.60	0.39	0.99
Minor – Other Outside Force	-	0.03	0.63	0.66
Major – Seismic	0.49	0.04	0.02	0.55
Major – Crossbore	0.29	0.00	0.02	0.31
Major – Other Outside Force	0.24	0.02	0.04	0.30
Minor – Crossbore	-	0.00	0.01	0.01
Aggregated	19.04	8.81	78.87	106.7

Controls and Mitigations

Controls:

PG&E identifies 29 control programs (LOCDM-C001 to LOCDM-C029) in Table 2-6[431] of the 2024 RAMP Report. For the 2027-2030 period, PG&E plans to continue 24 of these control programs,[432] four of

430 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-24,

431 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-27 to 2-28.

432 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-38, lines 3-4.

which are identified as foundational activities. As shown in Table 11-5, PG&E provides a total program cost estimate of approximately $1.5 billion for controls over the 2027-2030 period.

Table 11-4. LOCDM Foundational Activities Cost Estimates (2027-2030)[433]

Item No	Control ID	Control Name	Enabled Control and Mitigation IDs	Millions of Dollars (NPV) (2027-2030)
1	LOCDM-C012	Plastics Program	LOCDM-C010, LOCDM-M005, LOCDM-M007	$0.79
2	LOCDM-C013	Training, Gas Qualifications	LOCDM-C002, LOCDM-C003, LOCDM-C004, LOCDM-C006, LOCDM-C007, LOCDM-C008, LOCDM-C009, LOCDM-C010, LOCDM-C011, LOCDM-C014, LOCDM-C017, LOCDM-C018, LOCDM-C019, LOCDM-C020, LOCDM-C023, LOCDM-C024, LOCDM-C026, LOCDM-C027, LOCDM-M001, LOCDM-M002, LOCDM-M003, LOCDM-M004, LOCDM-M005, LOCDM-M007, DUNGD-C016, PCEEE-C001, LRGOP-C013	$2.92
3	LOCDM-C015	Gas Distribution Control Center Operations	LOCDM-C002, LOCDM-C004, LOCDM-C008, LOCDM-C009,	$23.57

433 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-37.

Item No	Control ID	Control Name	Enabled Control and Mitigation IDs	Millions of Dollars (NPV) (2027-2030)
			LOCDM-C014, LOCDM-C018, LOCDM-C019, LOCDM-C020, LOCDM-C024, LOCDM-C026, LOCDM-C027, LOCDM-M001, LOCDM-M002, LOCDM-M004, LOCDM-M006, LRGOP-C013	
4	LOCDM-C025	Dig-In Reduction Team	DUNGD-C016, PCEEE-C001, LOCDM-C017	$8.36
5	Total			$35.65
Note	NPV = Net Present Value uses the base year of 2023			

Table 11-5. LOCDM Controls Cost Estimates and Cost Benefit Ratios (2027-2030)[434]

Item No	Control ID	Control Name	Millions of Dollars (NPV)			CBR
			Program Cost (2027-2030) (A)	Foundational Activity Cost (B)	Risk Reduction (C)	(C)/[(A) +(B)]
1	LOCDM-C001	Meter Protection	$18.7	-	$0.1	<0.1
2	LOCDM-C002	Improve System Reliability – Gas Main	$231.4	$3.2	$1.8	<0.1
3	LOCDM-C003	Improve System Reliability – Gas Services	$36.3	$0.0	$0.2	<0.1
4	LOCDM-C004	Improve System Reliability – Gas Valves	$29.8	$0.4	$12.5	0.4
5	LOCDM-C005	Improve System Reliability – Gas Other Equipment	$4.3	-	$0.0	<0.1
6	LOCDM-C006	Improve System Reliability – Cut-Off Idle Gas Services	$18.7	$0.0	$0.1	<0.1
7	LOCDM-C007	Improve ReM/R/V	$25.3	$0.0	$0.9	<0.1
8	LOCDM-C008, LRGOP-C013	Major Event – Distribution Gas	$1.2	$0.0	$7.8	6.2
9	LOCDM-C009	Encroachment Program	$95.7	$1.3	$0.4	<0.1
10	LOCDM-C010	Tee Cap Replacement Program	$4.6	$0.8	$16.9	3.2
11	LOCDM-C011	DIMP Emergent Work	$5.1	$0.0	$0.1	<0.1
12	LOCDM-C014	Distribution Leak Management	$598.9	$8.3	$44.1	0.1
13	DUNGD-C016, PCEEE-C001, LOCDM-C017	Locate and Mark – Distribution	$231.1	$8.5	$113.3	0.5
14	LOCDM-C018	Distribution Corrosion Control Program	$140.6	$1.9	$201.1	1.4
15	LOCDM-C019	Casings	$18.9	$0.3	$0.0	<0.1

[434] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-39.

Item No	Control ID	Control Name	Millions of Dollars (NPV) Program Cost (2027-2030) (A)	Foundational Activity Cost (B)	Risk Reduction (C)	CBR (C)/[(A)+(B)]
16	LOCDM-C020	Atmospheric Corrosion, Mains and Services	$30.3	$0.4	$0.2	<0.1
17	LOCDM-C023	Preventive Maintenance Gas Services	$5.1	$0.0	$0.1	<0.1
18	LOCDM-C024	Corrective Maintenance, Gas, Main Valve	$1.4	$0.0	$0.1	0.1
19	LOCDM-C026	Maintenance, Preventative, Gas Valves	$5.3	$0.1	$16.7	3.1
20	LOCDM-C027	Preventive Maintenance Gas Mains	$5.1	$0.1	$0.2	<0.1
Note	NPV = Net Present Value uses the base year of 2023					

Observations:

SPD observes that a small number of controls account for the large majority of the total cost estimates. The largest, LOCDM-C014-Distribution Leak Management, has a cost estimate of $803 million over the 2027-2030 period, or approximately 42 percent of the total estimated costs of the chapter's controls. Combining this with costs of the next three largest controls (LOCDM-C017-Locate and Mark – Distribution, LOCDM-C002-Improve System Reliability – Gas Main, and LOCDM-C018-Distribution Corrosion Control Program) accounts for approximately 82 percent of total control costs, with the other 16 controls accounting for the remaining 18 percent of cost estimates.

SPD also observes the relatively poor CBR values for most controls, including previously listed higher cost programs (except for LOCDM-C018-Distribution Corrosion Control Program). As shown in Table 11-5, of the 20 control programs in the LOCDM chapter where PG&E provides a CBR value, 16 fall below a breakeven CBR of 1.0, with 14 of those having an exceptionally low CBR values of 0.1 or less. While SPD acknowledges that some activities may be related to regulatory compliance, it is unclear in the 2024 RAMP which control programs fall under that category. SPD recommends PG&E be required to provide justification in the General Rate Case (GRC) filing for spending on any of the 16 controls with a CBR less than 1.0.

Mitigations:

PG&E lists 6 total mitigation programs (LOCDM-M001 to LOCDM-M006) in Table 2-7[435] of the PG&E 2024 RAMP Report. For the 2027-2030 period, PG&E proposes to perform the four mitigation programs listed below.[436]

1. **LOCDM-M001-Pipeline Replacement Program (Steel):** This program aims to replace pre-1941 steel pipe with new plastic or steel. PG&E may also use risk modeling to determine higher risk post-1940 pipe for replacement. PG&E plans to use a risk ranking that considers pipe age, leak history, cathodic protection (CP), coating, seismic activities, and population proximity.[437]

2. **LOCDM-M002-Pipeline Replacement Program (Plastic):** This program is designed to mitigate risks associated with plastic pipe installed before 1985 made of Aldyl-A or other similar plastic materials, which are known to be prone to leaks. PG&E plans to use a risk ranking that considers leak history, pipe age, material type, ground temperature, diameter, operating pressure, and population proximity.[438]

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435 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-28.

436 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-40, lines 2-3.

437 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-33, lines 14-22.

438 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 2, page 2-33, lines 23-30.

3. **LOCDM-M004-New Valve Installations:** This program will install valves that allow PG&E to reduce the size of emergency shutdown zones, therefore improving PG&E's ability to isolate the gas system in the event of an emergency.[439]

4. **LOCDM-M006-Cross Bore Program:** This program aims to inspect, identify, and remediate cross-bores on the gas distribution system by using video equipment to inspect storm drain and wastewater systems. The program also incorporates a public outreach component to provide safety information to PG&E customers, sewer districts, and public works agencies.[440]

Table 11-6. LOCDM Mitigations Cost Estimates and Cost Benefit Ratios (2027-2030)[441]

Item No	Mitigation ID	Mitigation Name	Millions of Dollars (NPV)			CBR
			Total Program Cost (2027-2030) (A)	Foundational Activity Cost (B)	Risk Reduction (C)	(C)/[(A)+(B)]
1	LOCDM-M001	Pipeline Replacement Program (Steel)	$467.9	$6.5	$35.2	0.1
2	LOCDM-M002	Pipeline Replacement Program (Plastic)	$1,933.6	$26.7	$86.3	<0.1
3	LOCDM-M004	New Valve Installations	$24.5	$0.3	$9.8	0.4
4	LOCDM-M006	Cross Bore Program	$23.3	$0.3	0.3	<0.1
Note	NPV = Net Present Value uses the base year of 2023					

Observations:

SPD observes that of the total proposed costs of approximately $2.4 billion for LOCDM mitigations during the 2027-2030 period, the two Pipeline Replacement Program mitigations (M001-Pipeline Replacement Program (Steel) and M002-Pipeline Replacement Program (Plastic)) comprise over 98 percent of that spending. M002-Pipeline Replacement Program (Plastic) accounts for $1.9 billion of that spending alone, greater than the projected costs of all control programs combined (about $1.5 billion), and nearly 50 percent of all spending on LOCDM controls and mitigations.

SPD also observes the relatively low CBR values for the proposed mitigations. As can be seen in Table 11-6, of the four mitigation programs listed in the LOCDM chapter, all fall below a breakeven CBR of 1.0, with M001, M002, and M006 all having exceptionally low CBRs of 0.1 or less. While SPD acknowledges that

[439] PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2, page 2-34, lines 3-6.
[440] PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2, page 2-34, lines 10-17.
[441] PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2 page 2-41 to 2-42.

PG&E identifies regulatory compliance as factors for selecting M002-Pipeline Replacement Program (Plastic) and M004-New Valve Installations, it is unclear whether all projects within these two programs are necessary to satisfy regulatory requirements. SPD recommends PG&E provide justification in its 2027 General Rate Case (GRC) filing for spending on any projects associated with the mitigations in this chapter.

Alternatives Analysis

In the 2024 RAMP, PG&E considers three alternative mitigations for LOCDM risk, providing cost estimates, risk reduction values, and CBR values for each plan as shown in Table 11-7. PG&E separates these three mitigations into two "Alternative Plans."

1. **Alternative Plan 1**: PG&E considers LOCDM-A001 – Electrification – Steel and LOCDM-A002 – Electrification – Plastic as alternatives to the Pipeline Replacement Program (M001 and M002). With these alternative mitigations, gas infrastructure planned for replacement would instead be deactivated and all affected customers would be retrofitted for all-electric service.[442]

2. **Alternative Plan 2:** PG&E considers LOCDM-A003 – Residential Detection Meters (RDMs), a program where devices, such as smoke detectors, are placed near residential gas services to detect and alert PG&E and nearby members of the public when gas concentrations begin approaching dangerous levels (typically 10 percent of the lower explosive limit). In 2023, PG&E began a pilot program placing RDMs at inside meter set locations, targeting the tranches consisting of indoor risers in high population density areas, with steel pipes older than 1941 or plastic pipes older than 1985. PG&E does not plan to install additional devices but will continue evaluating the results of currently installed RDMs.[443]

[442] PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2, page 2-47 to 2-48.
[443] PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2, page 2-50 to 2-51.

Table 11-7. LOCDM Alternative Mitigations Cost Estimates and Cost Benefit Ratios (2027-2030)[444]

Item No	Alternative Mitigation ID	Alternative Mitigation Name	Millions of Dollars (NPV)		CBR
			Total Program Cost (2027-2030) (A)	Risk Reduction (B)	(B)/(A)
1	LOCDM-A001	Electrification - Steel	$409.2	$39.1	0.1
2	LOCDM-A002	Electrification - Plastic	$2,766.0	$119.6	<0.1
3	LOCDM-A003	Residential Detection Meters (RDMs)	$41.3	$0.4	<0.1
Note	NPV = Net Present Value uses the base year of 2023				

Observations:

SPD observes that Alternative Plan 1 offers several benefits. The complete removal of a large portion of gas distribution infrastructure completely removes all LOCDM risk associated with that infrastructure, replaces high-cost mitigation programs (M001 and M002), and offers additional climate change benefits by reducing greenhouse gas emissions. However, SPD supports PG&E's decision not to pursue Alternative Plan 1. Both alternative mitigations in the plan have high costs, even compared to the high costs of the Pipeline Replacement Program that Alternative Plan 1 would replace. A001 and A002 also have low CBR values. Moreover, PG&E acknowledges that conversion would require customer consent, with the program's effectiveness severely limited unless 100 percent of services in a pipe segment are converted.[445]

SPD also observes the low CBR of LOCDM-A003 – Residential Detection Meters (RDMs) associated with Alternative Plan 2. Given that PG&E has recently installed several RDMs near customer services as part of a pilot program, SPD supports PG&E's decision to not continue with further installations unless future evaluation of the pilot program reveals benefits significantly greater than those presented in the 2024 RAMP.

SPD recommends that PG&E justify any projects associated with any alternative mitigations listed in the LOCDM chapter, if included in the 2027 GRC.

CBR Calculations

In this chapter, PG&E presented Cost-Benefit Ratio (CBR) calculations for controls and mitigations. Upon review, SPD recognizes that 16 of the controls and all 4 of the mitigations have CBR calculations less than the breakeven value of 1.0, specifically for the 2027-2030 GRC period. Table 11-8 lists the controls and

444 PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2, page 2-49 to 2-52.
445 PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2, page 2-48, lines 6-10.

mitigations with CBRs under 1.0, as detailed in Exhibit PG&E-3, Chapter 2, Table 2-12,[446] Table 2-14,[447] and Table 2-15.[448]

Table 11-8. Summary of Controls and Mitigations with CBR Calculations Less than 1.0

Item No	Control/Mitigation ID	Control/Mitigation Name	Millions of Dollars (NPV)			CBR
			Program Cost (2027-2030) (A)	Foundational Activity Cost (B)	Risk Reduction (C)	(C)/[(A)+(B)]
1	LOCDM-C001	Meter Protection	$18.7	-	$0.1	<0.1
2	LOCDM-C002	Improve System Reliability – Gas Main	$231.4	$3.2	$1.8	<0.1
3	LOCDM-C003	Improve System Reliability – Gas Services	$36.3	$0.0	$0.2	<0.1
4	LOCDM-C004	Improve System Reliability – Gas Valves	$29.8	$0.4	$12.5	0.4
5	LOCDM-C005	Improve System Reliability – Gas Other Equipment	$4.3	-	$0.0	<0.1
6	LOCDM-C006	Improve System Reliability – Cut-Off Idle Gas Services	$18.7	$0.0	$0.1	<0.1
7	LOCDM-C007	Improve ReM/R/V	$25.3	$0.0	$0.9	<0.1
8	LOCDM-C009	Encroachment Program	$95.7	$1.3	$0.4	<0.1
9	LOCDM-C011	DIMP Emergent Work	$5.1	$0.0	$0.1	<0.1
10	LOCDM-C014	Distribution Leak Management	$598.9	$8.3	$44.1	0.1
11	DUNGD-C016, PCEEE-C001, LOCDM-C017	Locate and Mark – Distribution	$231.1	$8.5	$113.3	0.5

[446] PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2, Table 2-12 at 2-39.
[447] PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2, Table 2-14 at 2-41.
[448] PG&E 2024 RAMP Report, Exhibit PG&E-3, Chapter 2, Table 2-15 at 2-42.

Item No	Control/Mitigation ID	Control/Mitigation Name	Millions of Dollars (NPV)			CBR
			Program Cost (2027-2030) (A)	Foundational Activity Cost (B)	Risk Reduction (C)	(C)/[(A)+(B)]
12	LOCDM-C019	Casings	$18.9	$0.3	$0.0	<0.1
13	LOCDM-C020	Atmospheric Corrosion, Mains and Services	$30.3	$0.4	$0.2	<0.1
14	LOCDM-C023	Preventive Maintenance Gas Services	$5.1	$0.0	$0.1	<0.1
15	LOCDM-C024	Corrective Maintenance, Gas, Main Valve	$1.4	$0.0	$0.1	0.1
16	LOCDM-C027	Preventive Maintenance Gas Mains	$5.1	$0.1	$0.2	<0.1
17	LOCDM-M001	Pipeline Replacement Program (Steel)	$467.9	$6.5	$35.2	0.1
18	LOCDM-M002	Pipeline Replacement Program (Plastic)	$1,933.6	$26.7	$86.3	<0.1
19	LOCDM-M004	New Valve Installations	$24.5	$0.3	$9.8	0.4
20	LOCDM-M006	Cross Bore Program	$23.3	$0.3	0.3	<0.1
Note	NPV = Net Present Value uses the base year of 2023					

Observations:

SPD reviewed and assessed the controls and mitigations described in the LOCDM chapter of the 2024 RAMP and the CBR calculations performed in the workpaper.[449] In these resources, PG&E does not provide sufficient justifications for how these programs were selected for inclusion in the 2027-2030 GRC period, particularly those with CBRs under 1.0. Furthermore, it is unclear how PG&E determined the scale of these programs. It is unclear if spending over $2.4 billion on the Pipeline Replacement Program is appropriate for the 2027-2030 GRC period, particularly given that both the steel and plastic components of the program have a CBR of 0.1 or lower.

[449] Workpaper: Exhibit PG&E-3, Chapter 2, GO-LOCDM-3_CBR Input File.

SPD recommends PG&E be required to provide justification for any projects associated with the LOCDM risk in the upcoming 2027 GRC.

Summary of Findings

1. PG&E followed the RDF framework for risk assessment of the Loss of Containment on Gas Distribution Main or Service risk. This includes Risk Bow Tie, risk driver selection, consequence determination, exposure, tranches, cross-cutting factors, controls and mitigations, alternatives, and CBR calculations to mitigate risks.

2. The current definition of the risk creates a lack of clarity on what loss of containment events are included in the scope of the LOCDM risk analysis, specifically which loss of containment events without ignition qualify for consideration, and which were excluded.

3. PG&E chose to include both loss of containment events with and without ignition, as opposed to including only those with ignition, resulting in the following impacts to the risk analysis:

    a. A significantly higher frequency score
    b. A significantly lower consequence score
    c. A significantly lower contribution of safety consequences to the overall consequence score
    d. A significantly higher contribution of financial consequences to the overall consequence score

4. PG&E does not clearly define "minor" LOCDM events, specifically what distinguishes a "minor" LOCDM event that is included in the risk chapter from a loss of containment that does not qualify for inclusion.

5. As shown in Table 11-5, PG&E provided 20 controls, 16 of which had CBR calculations that fall below the breakeven value of 1.0. Little explanation was provided for why these programs were selected to be continued, given the low CBR values.

6. As shown in Table 11-6, PG&E provided 4 mitigations, all having CBR calculations below the breakeven value of 1.0. Little explanation was provided for why these programs were selected to be implemented, given the low CBR values.

Recommended solutions to address findings and deficiencies

Based on the findings and deficiencies identified in this chapter, SPD recommends PG&E be required to:

1. Clarify the definition of an LOCDM event, specifically how PG&E determines which non-ignition events are considered for inclusion. Alternatively, SPD recommends PG&E examine whether the scope of the risk should be altered to remove loss of containment events without ignition.

2. Provide detailed justification and explanation for both the inclusion and scale of any LOCDM control or mitigation with a CBR less than 1.0 in the upcoming GRC filing, as listed in Table 11-8.

12. Large Overpressure Event Downstream of Gas Measurement and Control (M&C) Facility

Risk Description

A Large Overpressure (OP) Event Downstream of Gas Measurement and Control (M&C) Facility (LRGOP) risk is defined as the failure of a gas M&C facility to perform its pressure control function, resulting in a large OP event downstream. M&C facilities are transmission and distribution regulator stations and regulator sets in PG&E's service territory. Large OP events potentially impact public safety, employee safety, contractor safety, property damage, financial losses, and the ability to deliver natural gas to customers.[450] Table 12-1 below is the risk definition.

[450] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-1, lines 9-14.

Table 12-1: Risk Definition and Scope

LARGE OVERPRESSURE EVENT DOWNSTREAM OF MEASUREMENT AND CONTROL (M&C)	
Definition	Failure of a gas M&C facility to perform its pressure control function resulting in a large OP event downstream that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers.
In Scope	Large OP Events[(a)]
Out of Scope	Other OP Events[(b)]
Data Quantification Sources	PG&E Large OP Event Data 2014-2022 Pipeline and Hazardous Materials Safety Administration (PHMSA) Reportable Incident Data 2010-2023.

(a) An OP event occurs when gas pressure exceeds the MAOP of the pipeline as determined by California Public Utilities Commission (CPUC or Commission)/Department of Transportation requirements. PG&E uses the below criteria to classify OP events as large OP events:

- High pressure distribution (1 pounds per square inch gauge (psig) ≤ MAOP < 12 psig): Pressure > 150% MAOP;
- High pressure distribution (12 psig ≤ MAOP < 60 psig): Pressure > MAOP + 6 psig;
- Low pressure distribution: Pressure > 16 inches water-column;
- Transmission: Pressure > 110% MAOP or produces a hoop stress of ≥ 75% Specified Minimum Yield Strength (SMYS), whichever is lower (based on 49 Code of Federal Regulations (CFR) 192.201); and
- Customer houseline: A large OP event occurs if one of the thresholds on customer rated equipment is breached, if customer equipment is damaged by excess pressure, or if LOC occurs due to excess pressure.

(b) OP events where the pressure exceeds the MAOP but does not meet any of the criteria in footnote (a).

Observations:

PG&E has thoroughly identified the LRGOP risk and defined a large overpressure event, including both transmission and distribution facilities. A large overpressure (OP) event is measured by the extent that the maximum allowable operating pressure (MAOP) has been exceeded, according to CPUC/ Pipeline and Hazardous Materials Safety Administration (PHMSA) definitions.

Bow Tie

PG&E presents critical information on the risk analysis of drivers and outcomes of the LRGOP risk in its Bow Tie model.

Observations:

The LRGOP Bow Tie identifies the following three drivers: Equipment Related, Incorrect Operations, and CC-Records and Information Management (RIM). While PG&E includes the CC-RIM cross-cutting factor as part of its bow tie analysis for LRGOP risk, SPD notes that other cross-cutting factors are omitted. Notably, OP events and the functioning of regulators are distinctly vulnerable to potential sabotage. Accordingly, SPD recommends that PG&E include two additional cross-cutting factors, Physical Attack and Cyber Attack, as risk drivers in the risk model for the LRGOP risk in its 2027 GRC filing.

PG&E conducted the Bow Tie analysis for LRGOP consistent with the CPUC's Risk-Based Decision-Making Framework (RDF). It utilized Drivers used to calculate the likelihood of a risk event (LoRE) on the left side of the model, and Outcomes to calculate the consequences of a risk event (CoRE) on the right side of the model (see Figure 12-1 below).

SPD agrees with PG&E's justification for increasing the number of outcomes from the 2020 RAMP. Separating the outcomes to align closely with different downstream pipelines will help quantify the consequences, frequency of outcomes, and risks more accurately.

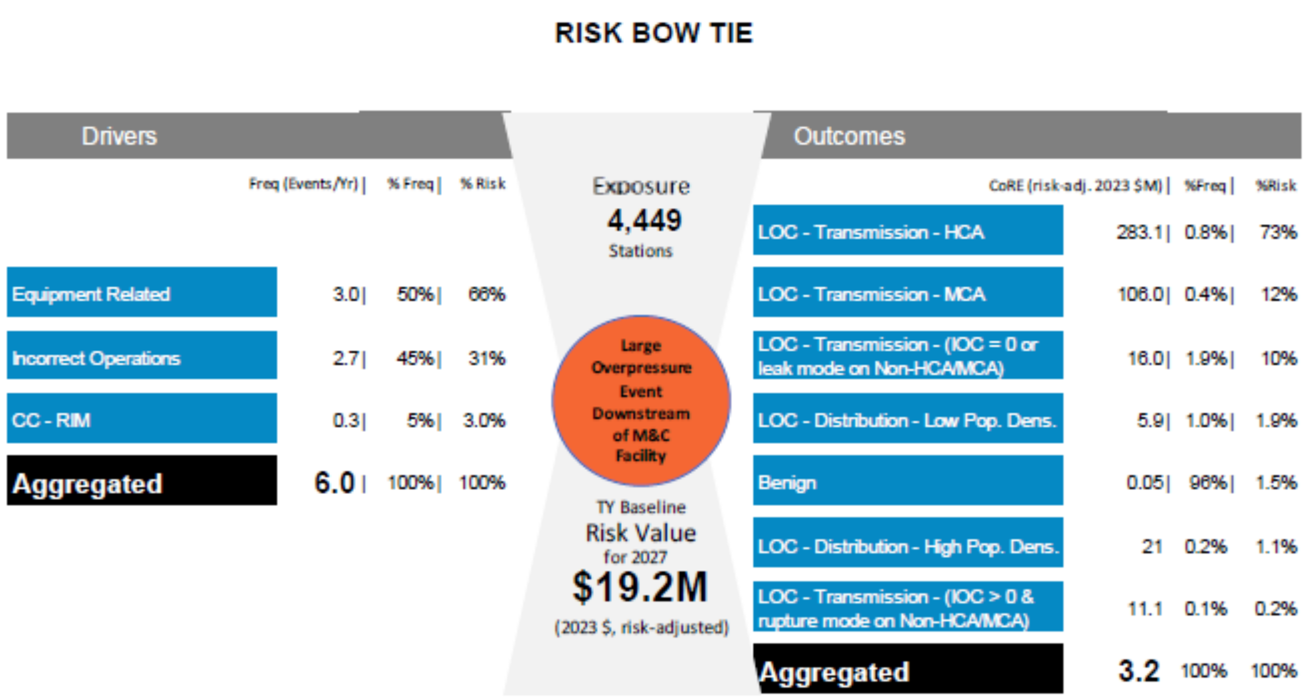

Figure 12-1: Risk Bow Tie

Exposure

PG&E's total exposure for the LRGOP risk is 4,449 Gas Measurement and Control Stations/Facilities.

Observations:

Using Gas Measurement and Control Stations/Facilities is consistent with the definition of "exposure" in the RDF. PG&E has 4,449 stations/facilities installed within the thousands of miles of its transmission and distribution pipelines.

Tranches

PG&E has identified seven facility-based tranches for this risk, with four tranches representing transmission facilities and three tranches distribution facilities. Each tranche represents a group of M&C stations with a relatively homogenous risk profile in terms of the likelihood and consequence of the risk event, and specific risk likelihood and consequence profiles can be assigned to each tranche.[451]

Observations:

SPD observes that 89 percent of the LRGOP risk is contained within the following two tranches:

- Transmission Complex Stations (14 percent)
- Transmission Large Volume Customer (LVC)-Type Facilities (75 percent)

Transmission Terminals became a standalone tranche when presented in PG&E's 2023 General Rate Case (GRC). The change to create a separate tranche for Transmission Terminals from Transmission Complex Stations allowed for more transparent modeling of PG&E's proposed terminal upgrade work to be applied to these stations.[452]

Risk Drivers

The risk drivers for PG&E's large OP event risk are based on investigations of these events that occurred at PG&E's M&C facilities. These investigations yielded causal information and helped define actions to prevent recurrence. Based on the results of its own investigations, PG&E identified two primary risk drivers, Equipment-Related and Incorrect Operations. A third risk driver used by PG&E is the cross-cutting factor RIM. Events associated with incorrect operations are generally a result of human performance, while

[451] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-6, lines 4-9.

[452] SPD Data Request, RAMP-2024_DR_SPD_011-Q001.

all other events can be considered equipment-related as occurrences due to pressure-regulating equipment failure.[453]

Observations:
SPD observes PG&E used data from 2014 through 2022, which contained 64 large OP events, to determine the frequency for the two drivers described above.

SPD agrees that most of the risk is related to equipment related failure rather than incorrect operations.

PG&E considered all threats (e.g., external factors) in the American Society of Mechanical Engineer (ASME) B31.8S as potential drivers for the LRGOP risk but only included drivers where PG&E has data supporting quantifying a large OP event likelihood.[454]

As discussed in the Bow Tie observation section, SPD recommends PG&E quantify the cross-cutting factors of Physical Attack and Cyber Attack as risk drivers for LRGOP risk.

Risk Driver Frequencies

To determine the likelihood of a large OP event in each of the tranches, PG&E analyzed its Large OP Event Data from 2014 through 2022 to classify these events by station type and risk driver. For this risk event, a total of seven tranches and two risk drivers are identified, resulting in 14 different risk event frequencies as inputs to the model.[455]

Observations:

The CC-RIM driver makes up five percent of the total frequency of an LRGOP risk event. SPD agrees that the Equipment Related and Incorrect Operations drivers make up most of the total frequency of a LRGOP risk event.

Outcome Frequencies

Large OP events can potentially lead to significant consequences. These consequences are most severe when the event results in LOC on downstream pipeline. Large OP events that do not result in LOC generally result solely in financial consequences. The large OP risk considers seven outcomes, classified into two main types: those where an LOC occurs and those where it does not.[456]

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453 2024 RAMP Report Exhibit PG&E-3 Chapter 3, page 3-10, lines 3-12.

454 SPD Data Request, RAMP-2024_DR_SPD_011-Q003.

455 2024 RAMP Report Exhibit PG&E-3 Chapter 3, page 3-11, lines 7-12.

456 2024 RAMP Report Exhibit PG&E-3 Chapter 3, page 3-11, lines 14-20.

Observations:

SPD agrees that the most frequent outcome is benign, as shown on the Bow Tie diagram. SPD agrees that most of the risk is concentrated on the LOC Transmission outcomes as confirmed in the Bow Tie diagram.

Cross-cutting factors

PG&E analyzed a total of seven cross-cutting factors, listed below in Figure 12-3

CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes*	No
2	Cyber Attack	Yes*	Yes*
3	Emergency Preparedness and Response	No	Yes*
4	Information Technology Asset Failure	No	Yes*
5	Physical Attack	Yes*	No
6	RIM	Yes	Yes
7	Seismic	No	No

Notes:

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

Figure 12-2: Cross-Cutting Factor Summary

Observations:

As shown in the Bow Tie, the total risk presented by cross-cutting factors is low. The CC-RIM cross-cutting factor PG&E quantifies in the model compromises approximately five percent frequency and three percent of the total LRGOP risk. SPD disagrees that physical attacks do not have an impact on the consequence of an overpressure event, as physical attacks may impact and worsen the consequences of an overpressure event. PG&E should explore ways to quantify the Physical Attack and Cyber Attack CCFs in the risk models.

Consequences

PG&E grouped consequences into seven outcomes, which are distinguished by three main categories: transmission, distribution, benign outcomes. Listed below are the seven outcomes:

1. LOC – Transmission – HCA
2. LOC – Transmission – MCA
3. LOC – Transmission – (IOC = 0 or leak mode on Non-HCA/MCA)
4. LOC – Distribution – Low Population Density
5. Benign
6. LOC – Distribution – High Population Density
7. LOC – Transmission – (IOC > 0 & rupture mode on Non-HCA/MCA)

Observations:

Six of the seven outcomes lead to LOC, resulting in 98.5 percent of the risk but only 4 percent of the frequency. The benign outcome has a 96 percent frequency, carries 1.5 percent of the risk, and generally results only in financial consequences. SPD observes that the Safety attribute drives consequences in the 2024 RAMP, a substantial change from the 2020 RAMP where consequences were driven by the Reliability attribute.

SPD observes that the consequence classifications PG&E uses do not distinguish ruptures or leaks that resulted in an ignition from ruptures or leaks that did not result in an ignition. SPD finds that there is significant variance in consequences for risk events when there is an ignition compared to when there is no ignition. Therefore, SPD recommends PG&E add distinctions for ignition and no ignition to further contextualize its LRGOP risk analysis.

Controls and Mitigations

Controls:

PG&E identified seven controls in the 2020 RAMP and 20 controls in the 2023 GRC. For its 2024 RAMP, PG&E is using 16 of the 20 controls named in the 2023 GRC, while removing the following four:

- LRGOP-C007 – Station Operations (Maintenance Activity Type (MAT) JPN)
- LRGOP-C010 – Operate Transmission Pipelines (MAT JOK)
- LRGOP-C014 – GDCC Operations (MAT FGA)
- LRGOP-C015 – GT&S Operations (MAT CMA)

Observations:

SPD observes that most of the proposed controls for the LRGOP risk have very low CBRs. See Table 12-1 which shows the Control ID, Program Name, and 2027-2030 Program Level CBRs.

Mitigations:

PG&E proposes the following six mitigations:

1. **LRGOP-M001 – GT Supervisory Control and Data Acquisition (SCADA) Visibility:** The GT SCADA Visibility Program installs SCADA at transmission stations and low points of elevation in the transmission system to enable a high degree of monitoring and control for the Gas Transmission Control Center (GTCC).[457]
2. **LRGOP-M002 – GT Overpressure Protection (OPP) Program:** This mitigation consists of the transmission portion of the M&C Station OPP Enhancements Program. The capital portion of the mitigation focuses on modifying or adding station equipment to provide secondary OPP.[458]
3. **LRGOP-M003 – GD OPP Program:** This mitigation consists of the distribution portion of the M&C Station OPP Enhancements Program. The capital portion of the mitigation focuses on modifying or adding station equipment to provide secondary OPP.[459]
4. **LRGOP-M005 – High Pressure Regulator (HPR) Program:** This program consists of removal or rebuild of HPR-Type facilities (including both HPR-Type district regulator stations and farm tap regulator sets) to address aging/obsolete equipment, corrosion issues, and designs not consistent with current design standards.[460]
5. **LRGOP-M006 – GD SCADA Visibility Electronic Recorder Transmitter (ERX):** The ERX component of the GD SCADA Visibility Program installs ERX SCADA devices to monitor distribution regulator stations or hydraulically independent systems (HIS) based on PG&E's established monitoring criteria. These devices are generally installed at stations that utilize spring-operated regulators.[461]
6. **LRGOP-M007 – GD SCADA Visibility Remote Terminal Unit (RTU):** The RTU component of the GD SCADA Visibility Program installs RTU devices at distribution regulator stations. These devices are generally installed at stations that utilize pilot-operated regulators.[462]

Observations:

PG&E proposed six mitigations with CBRs ranging from 0.006-0.971 (see Figure 12-5). The LRGOP-M002 GT OPP Program is the only mitigation with a CBR close to 1.0, at 0.971[463]. LRGOP-M004 – Critical Documents Program is a completed mitigation and is not part of the 2024 RAMP filing. Details regarding PG&E's planned units of work (see Figure 12-4), CBRs, and factors affecting mitigation selections (see Figure 12-5) for each proposed mitigation are provided below.

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457 PG&E 2024 RAMP, Exhibit PG&E-3 Chapter 3, page 3-23, lines 14-17.

458 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-23, lines 24-27.

459 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-24, lines 4-7.

460 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-24, lines 16-19.

461 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-25, lines 1-5.

462 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-25, lines 11-14.

463 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-32, line 5.

SPD observes that PG&E proposes to do only 19 percent of the proposed mitigation units of work in the top three most risky tranches, which account for 95 percent of the total risk score.

PLANNED MITIGATIONS 2027-2030

Line No.	Mitigation ID	Mitigation Name	Unit of Measurement[(a)]	Planned Units of Work 2027	2028	2029	2030	Total
1	LRGOP-M001	GT SCADA Visibility	Installations	5	5	5	5	20
2	LRGOP-M002	GT OPP Program	Stations	36	38	40	42	156
3	LRGOP-M003	GD OPP Program	Stations	51	52	53	54	210
4	LRGOP-M005	HPR Program	HPRs	80	80	80	80	320
5	LRGOP-M006	GD SCADA Visibility (ERX)	Installations	10	10	10	10	40
6	LRGOP-M007	GD SCADA Visibility (RTU)	Installations	40	40	41	42	163

(a) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from "rate case" units – the units referred to in PG&E's GRC or other proceedings.

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

Figure 12-3: Planned Mitigations 2027-2030

MITIGATION COST ESIMATES, RISK REDUCTION, CBR AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

Line No.	Mitigation ID	Mitigation Name	Thousands of Nominal Dollars 2027	2028	2029	2030	Millions of Dollars (NPV)[(a)] [A] Program Cost	[B] Foundational Activity Cost	[C] Risk Reduction	[C]/([A]+[B]) CBR[(b)]	Factors Affecting Selection
1	LRGOP-M001	GT SCADA Visibility	$1,571	$1,616	$1,664	$1,710	$6.2	$0.0	$0.6	0.1	Modeling Limitations
2	LRGOP-M002	GT OPP Program	20,164	20,726	21,324	21,921	81.8	0.0	79.5	1.0	Risk Tolerance
3	LRGOP-M003	GD OPP Program	7,593	7,711	7,849	8,011	33.1	0.0	0.5	<0.1	Risk Tolerance
4	LRGOP-M005	HPR Program	17,186	17,453	17,764	18,132	68.2	0.0	0.2	<0.1	Operational and Execution Considerations
5	LRGOP-M006	GD SCADA Visibility (ERX)	503	510	519	530	2.0	0.0	0.0	<0.1	Modeling Limitations
6	LRGOP-M007	GD SCADA Visibility (RTU)	11,253	11,428	11,631	11,872	44.6	0.0	0.4	<0.1	Modeling Limitations
7		Total	$58,270	$59,445	$60,750	$62,178					

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity Program costs.

For additional details see WP GO-LRGOP-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

Figure 12-4: Mitigation Cost Estimates, Risk Reduction, CBR and Factors Affecting Selection 2027-2030 Capital

Foundational Activities are listed as controls in LOCTM and LOCDM risk chapters, as detailed in Figure 12-5 below.

2027-2030 FOUNDATIONAL ACTIVITIES
(MILLIONS OF DOLLARS)

Line No.	Foundational Activity ID [(a)]	Foundational Activity Name	Foundational Activity Description	Enabled Control and Mitigation IDs [(a)]	Net Present Value (NPV)[(b)]
1	LOCTM-C038	Stan-Pac Expense	See description in in Exhibit (PG&E 3), Chapter 1.	LOCTM-C016, LRGOP-C011	$5.82
2	LOCDM-C013	Training, Gas Qualifications	See description in in Exhibit (PG&E 3), Chapter 2.	LOCDM-C008, LRGOP-C013	2.92
3	LOCDM-C015	Gas Distribution Control Center Operations	See description in in Exhibit (PG&E 3), Chapter 2.	LOCDM-C008, LRGOP-C013	23.57
4		Total			$32.31

Figure 12-5: 2027-2030 Foundational Activities (Millions of Dollars)

SPD notes that the Commission has not issued a decision regarding risk tolerance and PG&E did not provide more information on risk tolerance (e.g. defining a risk tolerance number or framework). Therefore, using risk tolerance as a factor affecting selection is not justified for the following mitigation: LGROP-M003 – GD OPP Program (CBR = 0.016).

SPD acknowledges that although modeling limitations may hinder the quantification of benefits for the following proposed mitigations, the CBRs for these mitigations are 1-2.22 orders of magnitude lower than the CBR threshold of 1.0. Therefore, justification for the following proposed mitigations is insufficient:[464]

- LRGOP-M001 – GT SCADA Visibility (CBR = 0.092)
- LRGOP-M006 – GD SCADA Visibility (ERX) (CBR = 0.006)
- LRGOP-M007 – GD SCADA Visibility (RTU) (CBR = 0.009)

Lastly, PG&E uses operational and execution considerations[465] as the sole justification for proposing the mitigation of LRGOP-M005 HPR Program (CBR = 0.003), with a CBR of 2.51 orders of magnitude lower

[464] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-33, lines 8-23.

[465] PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3.-33, lines 24-32, page 3-34, lines 1-28.

than 1.0. SPD recognizes that some steady-state asset replacement may be required to avoid failure of equipment. However, given the significantly low CBR and minimal justification for this mitigation, SPD recommends closely scrutinizing the scope and scale of LRGOP-M005 in PG&E's 2027 GRC filing. In case these mitigations with very low CBRs are needed to comply with regulatory requirements, PG&E should identify them as such, with the relevant regulatory requirements cited.

Alternatives Analysis

PG&E presents the following two alternative plans:

Alternative Plan 1: LRGOP-A001 – Rebuild Single-Run Stations: The distribution portion of the M&C Station OPP Enhancements Program is the LRGOP-M003 ‑ GD OPP Program. The capital portion of the mitigation focuses on modifying or adding station equipment to provide secondary OPP on Distribution District Regulator Stations (Non-HPR-Type), which are pilot-operated facilities. The type of secondary OPP installed is generally a "slam-shut" device. Alternative Plan 1 consists of replacing the LRGOP-M003 ‑ GD OPP Program with alternative mitigation LRGOP-A001 ‑ Rebuild Single-Run Stations. This alternative mitigation consists of station rebuilds on single-run stations beginning in 2027 and slam-shut retrofits on dual-run stations. The rebuilds would occur at a pace of 25 per year, addressing 100 single-run stations by the end of 2030.[466]

Alternative Plan 2: LRGOP-A002 – Relief Valves Downstream of Single-Run Stations: Alternative Plan 2 is similar to Alternative Plan 1 in that it includes an alternative to installing slam-shut devices at 100 single-run regulator stations. However, instead of rebuilding 100 single-run stations, this alternative mitigation includes installing secondary OPP in the form of a relief valve downstream of the station. Relief valves are widely used in the industry and, in contrast to slam-shut devices, allow gas to continue to flow downstream. Alternative Plan 2 consists of replacing LRGOP-M003 ‑ GD OPP Program with alternative mitigation LRGOP-A002 ‑ Relief Valves. This relief valve installation would begin in 2027 and will include slam-shut retrofits on dual-run stations. The relief valve installations would occur at a pace of 25 per year, addressing 100 single-run stations by the end of 2030.[467]

Observations:

PG&E's analysis of alternative mitigation plans is satisfactory and supports the justifications for not moving forward with the alternative plans. Workpaper GO-LRGOP-F Tables 3-16, 3-17, 3-18, and 3-19 contain the necessary information regarding the alternative plans' Program Cost, Risk Reduction, and CBR.

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466 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-35, lines 14-20 and page 3-36, lines 4-9.

467 PG&E 2024 RAMP, Exhibit PG&E-3, Chapter 3, page 3-38, lines 1-16.

CBR Calculations

PG&E calculated CBR values for 16 controls, six mitigations, and the two alternative mitigation plans. Table 12-2 below shows the 2027 through 2030 Program level CBR for all 24 programs.

Table 12-2: CBR Summary of all LRGOP Programs

ID	Program	2027-2030 Program CBR
LRGOP-C001	Perform Simple Station Rebuilds	0.016
LRGOP-C002	Perform Complex Station Rebuilds	0.008
LRGOP-C003	Perform Transmission Terminal Upgrade	0.026
LRGOP-C004	Routine Spend M&C	1.722
LRGOP-C005	Gas Quality Assessment - Expense	32.249
LRGOP-C008	Gas Distribution Reg Station Rebuild	0.002
LRGOP-C009	Gas Distribution Reg Station Component Replacements	0.031
LRGOP-C011	Vegetation Management	2.737
LRGOP-C012	Meter Maintenance	1.465
LRGOP-C013	Major Event - Distribution Gas	0.169
LRGOP-C016	Transmission SCADA Maintenance	0.545
LRGOP-C017	Distribution SCADA Maintenance	0.040
LRGOP-C018	Distribution Regulator Maintenance	0.011
LRGOP-C019	Farm Tap Maintenance	0.028
LRGOP-C020	Transmission Regulator Maintenance	0.755
LRGOP-M001	GT SCADA Visibility	0.092
LRGOP-M002	GT Overpressure Protection	0.971
LRGOP-M003	GD Overpressure Protection	0.016
LRGOP-M005	HPR Program	0.003
LRGOP-M006	GD SCADA Visibility (ERX)	0.006

ID	Program	2027-2030 Program CBR
LRGOP-M007	GD SCADA Visibility (RTU)	0.009
LRGOP-C006	FIMP Risk Assessment	2.114
LRGOP-A001-1	GD Overpressure Protection - slam-shut - A001	0.015
LRGOP-A001-2	GD Overpressure Protection - rebuild - A001	0.002
LRGOP-A002-1	GD Overpressure Protection - slam-shut - A002	0.015
LRGOP-A002-2	GD Overpressure Protection - relief valves - A002	0.011

Observations:

Controls:

The following six of 16 (38%) controls have a CBR greater than 1.0:

1. LRGOP-C004 Routine Spend M&C
2. LRGOP-C005 Gas Quality Assessment – Expense
3. LRGOP-C006 FIMP Risk Assessment
4. LRGOP-C011 Vegetation Management
5. LRGOP-C012 Meter Maintenance
6. LGROP-C013 Major Event – Distribution Gas

Mitigations:

None of the proposed mitigations have a CBR greater than 1.0. M002 – GT Overpressure Protection has a CBR of 0.971, and all other mitigations have CBRs that are orders of magnitude less than of 1.0.

Controls and Mitigations:

The average CBR of PG&E's 16 proposed controls is 2.62 and the average CBR of PG&E's six proposed mitigations is 0.18. The average CBR of controls is 14 times higher than the average CBR of mitigations. PG&E should continue to evaluate whether proposing mitigations with comparatively low CBRs is prudent.

Summary of Findings

1. SPD concludes the CBRs for the following mitigations proposed by PG&E in the 2024 RAMP application are several orders of magnitude lower than the breakeven value of 1.0:
   a. LRGOP-M001 – GT SCADA Visibility (CBR = 0.092)
   b. LRGOP-M003 – GD OPP (CBR = 0.016)
   c. LRGOP-M005 - HPR Program (CBR = 0.003)

   d. LRGOP-M006 – GD SCADA Visibility (ERX) (CBR = 0.006)
   e. LRGOP-M007 – GD SCADA Visibility (RTU) (CBR = 0.009)

2. Risk contained within each of the seven tranches vary substantially:
   - 95 percent of the risk is contained within the top three riskiest tranches (716 units or 16 percent of the total exposure for LRGOP):
     - Transmission – LVC – Type
     - Transmission – Complex
     - Transmission – Simple
3. SPD disagrees that physical attacks do not have an impact on the consequence of an overpressure event but do have the potential to impact and worsen the consequences of an overpressure event.
4. SPD finds PG&E does not distinguish ruptures or leaks that resulted in an ignition from ruptures or leaks that did not result in an ignition for consequence classifications. SPD finds that there is significant variance in consequences for risk events when there is an ignition compared to when there is no ignition.
5. SPD finds that PG&E proposes to do only 19 percent of the proposed mitigation units of work in the top three most risky tranches, which account for 95 percent of the total risk score.

Recommended solutions to address findings and deficiencies

11. SPD recommends PG&E continue to evaluate the appropriateness of including LRGOP-M001, LRGOP-M003, LRGOP-M005, LRGOP-M006, and LRGOP-M007 as mitigations within the 2024 RAMP/2027 GRC application for the reasons outlined in this report regarding use of modeling limitations, risk tolerance, and operational and execution considerations as justifications. SPD recommends PG&E provide further justification for the factors affecting mitigation selection in its 2027 GRC filing. If these mitigations with low CBRs are needed to comply with regulatory requirements, they should be identified as such. The relevant regulatory requirements must also be cited.
12. SPD recommends the scope and scale of LRGOP-M005 be closely scrutinized in PG&E's 2027 GRC filing.
13. SPD recommends PG&E propose work relating to LRGOP-M003 – GD OPP Program in the 2027 GRC filing conditioned on clear compliance requirements by an official PHSMA rulemaking (PHMSA Notice of Proposed Rulemaking (NPRM) – PHMSA-2021-0046).
14. SPD recommends the Commission and intervenors should thoroughly examine the low CBRs of PG&E's proposed mitigations in PG&E's 2027 GRC filing.
15. SPD recommends PG&E propose most of the mitigation work for the highest risk tranches in the 2027 GRC filing.
16. SPD recommends PG&E continue to evaluate whether proposing mitigations with low CBRs, when compared against the proposed controls, is prudent.
17. SPD recommends PG&E include the following cross-cutting factors as risk drivers: Physical Attack and Cyber Attack. OP events and the functioning of regulators are strongly vulnerable to sabotage involving these two cross-cutting factors.

18. SPD recommends PG&E consider the consequence of Physical Attacks in this risk.
    SPD recommends PG&E to quantify the Physical Attack and Cyber Attack cross-cutting factors and incorporate them into the risk models.
19. SPD recommends PG&E distinguish whether ruptures or leaks resulted in an ignition for consequence classifications.

Safety Policy Division Evaluation Team

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Acknowledgements

The SPD evaluation team would like to acknowledge the contributions during public workshops and from informal written comments made by intervenor parties as well as PG&E in this RAMP proceeding, including California Public Advocates (Cal Advocates), Energy Producers & Users Coalitio (EPUC) and Indicated Shippers, the Mussey Grade Road Alliance (MGRA), Small Business Utility Advocates (SBUA), and The Utility Reform Network (TURN).

Informal Intervenor Comments

Attachment 1: California Public Advocates (Cal Advocates)

Attachment 2: EPUC and Indicated Shippers

Attachment 3: Mussey Grade Road Alliance (MGRA)

Attachment 4: Small Business Utility Advocates (SBUA)

Attachment 5: The Utility Reform Network (TURN)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2024 Risk Assessment and Mitigation Phase Report	Application 24-05-008

THE PUBLIC ADVOCATES OFFICE CORRECTED INFORMAL COMMENTS ON THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U39M) TO SUBMIT ITS 2024 RISK ASSESSMENT AND MITIGATION PHASE (RAMP) REPORT

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October 15, 2024

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Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2024 Risk Assessment and Mitigation Phase Report	Application 24-05-008

THE PUBLIC ADVOCATES OFFICE CORRECTED INFORMAL COMMENTS ON THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U39M) TO SUBMIT ITS 2024 RISK ASSESSMENT AND MITIGATION PHASE (RAMP) REPORT

I. INTRODUCTION

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) hereby submits these informal comments on Pacific Gas and Electric Company's (PG&E) Application (A.) 24-05-008 regarding its 2024 Risk Assessment and Mitigation Phase (RAMP) Report ("PG&E's RAMP Report").[1]

Cal Advocates identifies significant concerns and shortcomings with PG&E's RAMP Report that are detailed in Section II of these comments. Cal Advocates recommends that SPD require PG&E to supplement its RAMP Report and that SPD consider Cal Advocates' concerns in its report on PG&E's RAMP Report, as described in Section II.

[1] A.24-05-008, *Application of Pacific Gas and Electric Company to Submit its 2024 Risk Assessment and Mitigation Phase Report*, May 15, 2024.

II. COMMENTS

A. PG&E failed to provide a meaningful comparison of covered conductor against undergrounding as an alternative wildfire mitigation in its RAMP.

Two primary industry methods to mitigate wildfire risk are to (1) replace overhead distribution lines with insulated covered conductors or (2) replace overhead distribution lines with underground conductors.

PG&E plans 608 miles of work units for 2024-2026 in its "System Hardening [Overhead]" (covered conductor) program and 950 miles of work units for 2024-2026 in its "System Hardening [Underground]" program.[2]

PG&E's proposed undergrounding program ("M022")[3] would convert overhead distribution lines and equipment to underground lines. Instead of proposing an alternative to the M022 undergrounding program that compares the costs and benefits of covered conductor to undergrounding, PG&E compared M022 undergrounding to these two primary alternatives:

1. A second alternative undergrounding mitigation proposal that only undergrounds primary conductors, and not secondary conductors and service lines ("A001").[4, 5] PG&E has stated service lines are not included in its undergrounding program.[6]
2. An alternative mitigation proposal that substitutes Grid Monitoring for undergrounding ("A002").[7, 8]

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[2] PG&E's RAMP Report at PG&E-4 1-71.

[3] DOVHD-M022, PCEEE-M003, WLDFR-M022 (System Hardening [Underground]).

[4] DOVHD-A001, WLDFR-A001, PCEEE-A003 (System Hardening [Underground] (Alternative Workplan)).

[5] PG&E's RAMP Report at PG&E-4 1-98 and 4-45.

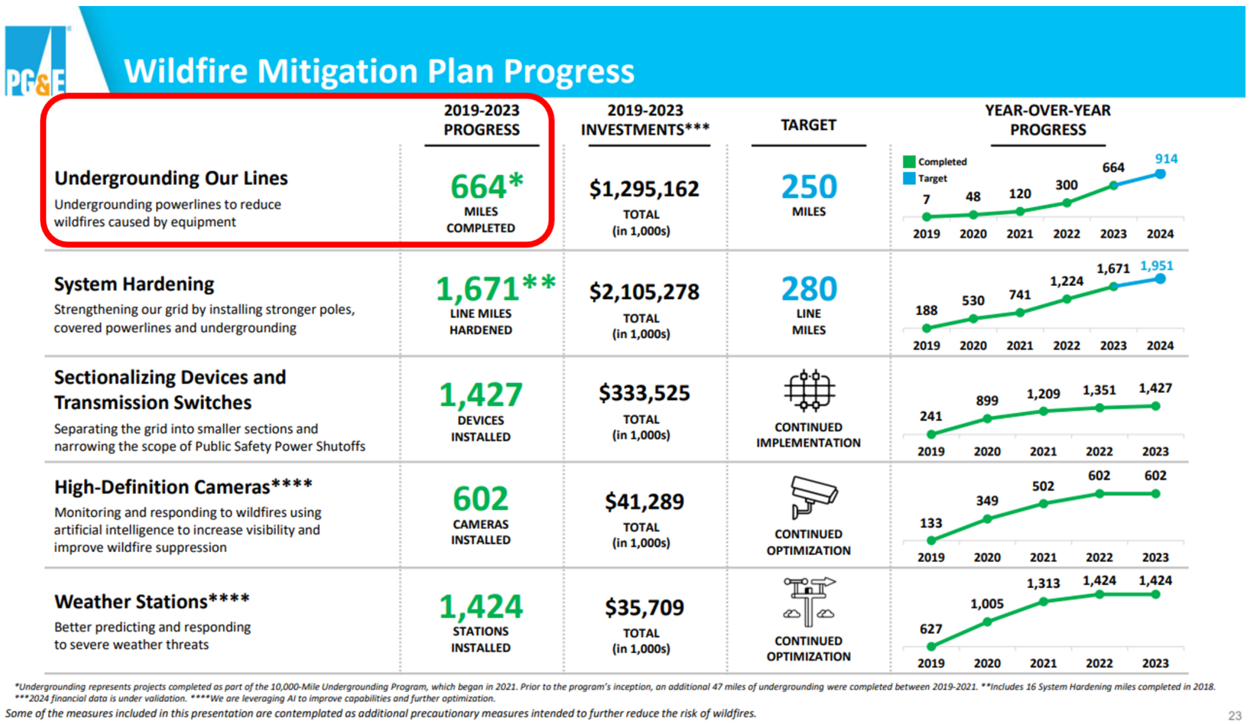
[6] PG&E "Undergrounding Fact Sheet", available at https://www.pge.com/assets/pge/docs/outages-and-safety/safety/undergrounding-fact-sheet.pdf

[7] DOVHD-A002, WLDFR-A002 (Grid Monitoring).

[8] PG&E's RAMP Report at PG&E-4 1-100 and 4-48.

PG&E's August 28, 2024 presentation to Commissioners included the following slide, which depicts PG&E's progress in undergrounding 664 miles of line since 2019.[9]

Figure 1: PG&E Wildfire Mitigation Plan Progress[10]



For comparison, Southern California Edison Company (SCE), presented slides in its August 29, 2024 presentation,[11] which depict SCE's greater progress in using covered conductor to harden 5,600 miles of conductor since 2018. SCE asserted that is has

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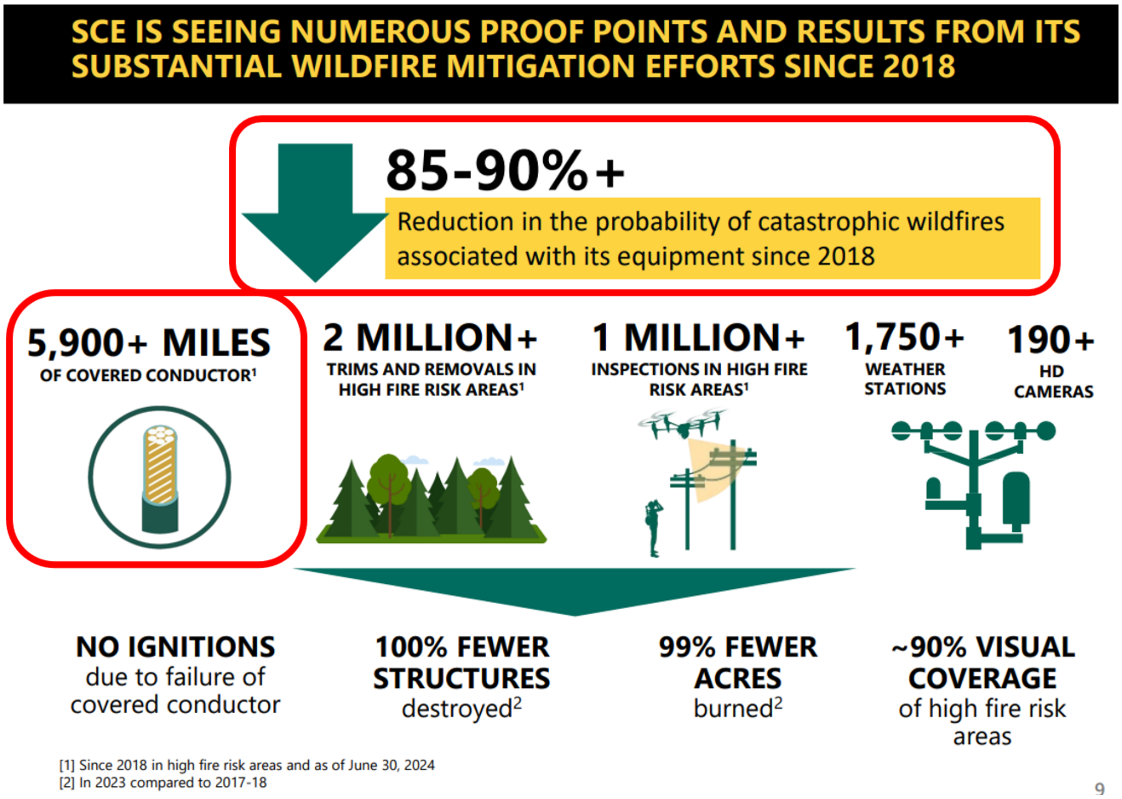
[9] PG&E Annual Public Safety Briefing, August 28, 2024, slide 23. Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/pge_cpuc-safety-briefing_082824.pdf

[10] PG&E Annual Public Safety Briefing, August 28, 2024, slide 23. [Red circle highlight added] Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/pge_cpuc-safety-briefing_082824.pdf

[11] SCE CPUC/Energy Safety Public Meeting on Safety, August 29, 2024, slide 9. Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-cpuc-oeis-bod-safety-public-meeting_082924.pdf

reduced the probability of catastrophic wildfires from its equipment by 85-90%+ since 2018.[12]

Figure 2: SCE Wildfire Mitigation Efforts Since 2018[13]



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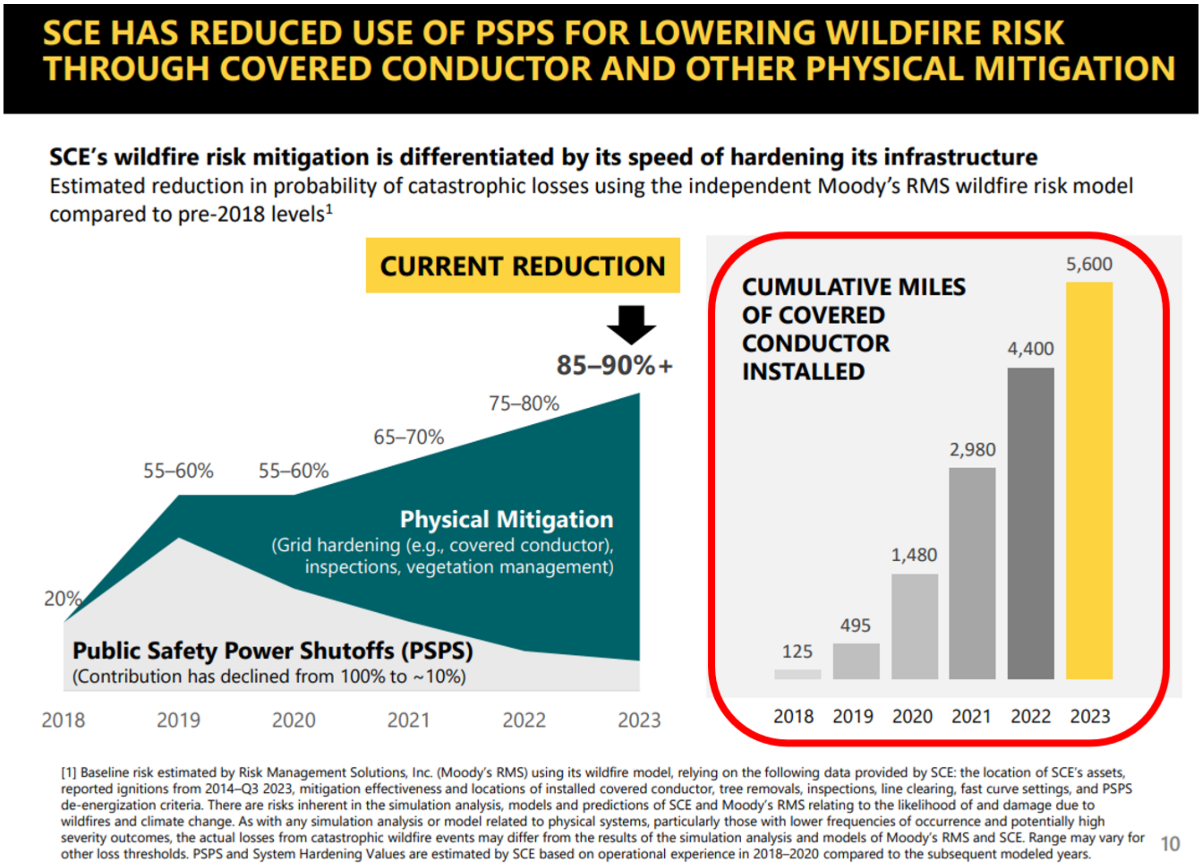
[12] SCE CPUC/Energy Safety Public Meeting on Safety, August 29, 2024, slide 9. Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-cpuc-oeis-bod-safety-public-meeting_082924.pdf

[13] SCE CPUC/Energy Safety Public Meeting on Safety, August 29, 2024, slide 9. [Red circle highlights added] Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-cpuc-oeis-bod-safety-public-meeting_082924.pdf

Figure 3: SCE Reduction in PSPS Through Covered Conductor[14]



Decision (D.)14-12-025 directs utilities to provide two alternative risk mitigations for each RAMP risk proposal.[15] PG&E, in choosing the alternatives it presented to the Commission for its undergrounding program, failed to provide a detailed analysis of the

[14] SCE CPUC/Energy Safety Public Meeting on Safety, August 29, 2024, slide 10. [Red circle highlight added] Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-cpuc-oeis-bod-safety-public-meeting_082924.pdf

[15] D.14-12-025, *Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan and Modifying Appendix A of Decision 07-07-004*, December 9, 2014, at 32 and 37-38. ("The Refined Straw Proposal recommends that the utility's RAMP report contain at least the following…For comparison purposes, at least two other alternative mitigation plans the utility considered and an explanation of why the utility views these plans as inferior to the proposal plan… We adopt the following RAMP process...The utility's RAMP submission shall contain the information that the Refined Straw Proposal has described, as summarized above.")

costs and benefits of covered conductor as one of its two alternatives to its M022 undergrounding program proposal.

PG&E stated that general factors that may result in undergrounding as the preferred mitigation include tree strike potential, proximity to a major ingress or egress route, localized fuel types, and past fire history.[16] PG&E also stated that undergrounding of secondary and service lines provides additional benefits that are not as easily quantified, such as improvements to Public Safety Power Shutoffs (PSPS), end of line reliability, and customer satisfaction.[17]

SCE, however, has also seen a significant reduction in the use of PSPS from its covered conductor program, as depicted in Figure 3 above.

Furthermore, SCE states:

> SCE's wildfire risk mitigation is differentiated by its speed of hardening its infrastructure.[18]

Cal Advocates recommends that SPD and the Commission require PG&E to supplement its RAMP submission, and all future RAMPs and General Rate Case (GRC) applications, with a detailed comparison of the costs and benefits of covered conductor as an alternative to all undergrounding proposals.

B. PG&E failed to provide an adequate justification for its decision to select a $6.5 billion undergrounding wildfire mitigation program over a $1.7 billion covered conductor alternative.

In response to a data request from Cal Advocates, PG&E disclosed that a covered conductor program alternative to its M022 undergrounding would cost close to $5 billion less than its undergrounding proposal.[19] PG&E also disclosed that the cost-benefits of a covered conductor program alternative are more than twice that of its undergrounding

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[16] PG&E's RAMP Report at PG&E-4 1-58.

[17] PG&E's RAMP Report at PG&E-4 1-98 and 4-46.

[18] SCE CPUC/Energy Safety Public Meeting on Safety, August 29, 2024, slide 10. Access at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/sce-cpuc-oeis-bod-safety-public-meeting_082924.pdf

[19] PG&E's Data Request Response *RAMP-2024_DR_CalAdvocates_004-Q002Atch01*.

proposal.[20] In other words, a cost-benefits analysis overwhelmingly favored covered conductor as a wildfire mitigation over costly and slow undergrounding.

When asked to justify its decision to select undergrounding over covered conductor, PG&E responded that:

> PG&E chose undergrounding as our preferred mitigation because it provides the most wildfire risk reduction, significantly improves customer reliability, especially surrounding [Enhanced Powerline Safety Settings (EPSS)] and PSPS outages, and provides an electric distribution system which is more resilient to the adverse impacts of climate change with deep uncertainty. Undergrounding also substantially addresses factors such as ingress/egress and tree fall-in risk, which are not mitigated by an overhead alternative. Additional considerations influencing the decision to pursue the most risk reducing mitigation include Risk Tolerance, modeling limitations, and other uncertainties affecting the analysis.
>
> For more information on PG&E's undergrounding mitigation please see PG&E's 2023-2025 WMP: 2023-2025 Wildfire Mitigation Plan R6 (pge.com), sections 8.1.2.1 and 8.1.2.2.[21]

PG&E's justification lacks evidentiary support and does not address why PG&E selected undergrounding as opposed to covered conductor, which is a less costly and has a better cost-benefit ratio (CBR). PG&E's RAMP is the first RAMP to incorporate the Commission's new Cost-Benefit Approach (CBA) for selection of risk mitigation programs. While a utility is not required to select a mitigation based solely on a cost benefits analysis,[22] PG&E's unsupported narrative is not sufficient.

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[20] See PG&E's Data Request Response *RAMP-2024_DR_CalAdvocates_004-Q002Atch01.*

[21] See PG&E's Data Request Response *RAMP-2024_DR_CalAdvocates_004-Q001*.

[22] D.22-12-027, Appendix A at Row 26: "In the RAMP and GRC, the utility will clearly and transparently explain its rationale for selecting Mitigations for each risk and for its selection of its overall portfolio of Mitigations. The utility is not bound to select its Mitigation strategy based solely on the Cost-Benefit Ratios produced by the Cost-Benefit Approach. Mitigation selection can be influenced by other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis. In the GRC, the utility will explain whether and how any such factors affected the utility's Mitigation selections."

C. PG&E failed to evaluate the risk from delayed mitigation of wildfire risk due to the necessary extended time needed to implement undergrounding as an urgent wildfire mitigation.

PG&E needs to consider the unmitigated and ongoing wildfire risk that continues during the lengthy time needed to implement undergrounding. A typical overhead hardening project can advance from concept to execution, documentation, and close out in 13-16 months, whereas a typical underground project can often take 18-45 months depending on the various risks presented.[23] Undergrounding can take 2-29 months longer to implement compared to an overhead hardening project, which means wildfire will still pose as a risk to the public while the undergrounding project is underway. PG&E needs to evaluate the risk from the extended time needed to implement undergrounding compared to overhead hardening before selecting undergrounding as a primary mitigation measure.

D. PG&E should calculate the cost-benefit ratios of its undergrounding program as both a safety mitigation and a reliability mitigation.

PG&E assigns a risk value of $22.0 billion to "wildfire risk with PSPS and EPSS" in 2023.[24] Operational mitigations such as PSPS and EPSS are likely to reduce that risk by approximately $19.4,[25] but create their own reliability risks, totaling approximately $6.0 billion.[26]

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[23] A.21-06-021, *PG&E's 2023 GRC, Exhibit (PG&E-4), Workpapers Supporting Chapters 2-13, Volume 1 of 2*, February 25, 2022, at WP 4-90.

[24] PG&E 2024 RAMP Workshop #3, June 18, 2024, slide 33.

[25] Per PG&E 2024 RAMP Workshop #3, June 18, 2024, slide 33, PSPS and EPSS provide a $17.3 billion risk reduction in 2027, down from an expected total wildfire risk of $19.6 billion. This is approximately an 88 percent reduction. Applying this value to the 2023 wildfire risk of $22 billion results in a risk reduction of $19.4 billion, or a residual wildfire risk of $2.6 billion.

[26] Per PG&E 2024 RAMP Workshop #3, June 18, 2024, slide 33, PSPS and EPSS create new reliability risk totaling $5.3 billion, compared to a $17.3 billion risk reduction in 2027 due to the same mitigations. This is about a 30 percent risk add. Applying this value to the predicted $19.6 billion risk reduction in 2023 suggests that, in 2023, PSPS and EPSS will introduce approximately $6 billion of reliability risk in 2023.

These numbers suggest that PG&E's *current* risk for "wildfire risk with PSPS and EPSS" is closer to $8.6 billion, rather than the $22 billion shown.[27] Further, more than two thirds of this $8.6 billion is due to *reliability*, rather than safety risk.

Grid resiliency measures such as undergrounding will further mitigate safety risk. However, given that the majority of present-day risk is actually related to reliability, grid resilience will primarily mitigate reliability risk by hardening miles and removing them from the scope of PSPS and EPSS.

PG&E should assess the cost-benefit ratios of grid resiliency efforts such as undergrounding as primarily being a *reliability* mitigation. This will likely result in lower expected benefits because the present reliability risk is substantially lower than the present wildfire risk before PSPS and EPSS. Due to PG&E's non-linear risk scaling function, this methodology would likely produce substantially lower CBRs for grid resilience measures.

The Commission should require utilities to evaluate undergrounding both by its perceived safety benefits (permanent wildfire risk reduction) as well as by the practical effects under PG&E's modern operations framework (permanent reliability benefits).

E. PG&E should include an analysis and forecast of ratepayer bill impacts when comparing alternative risk mitigation programs.

PG&E should consider ratepayer bill impacts when evaluating alternative risk program mitigations and when justifying selection of a particular mitigation. However, its RAMP Report provides no such analysis.[28, 29] Ratepayer impact is critical information for the Commission to consider to ensure that rates are just and reasonable.[30] Cal Advocates recommends that SPD require PG&E to supplement its RAMP Report with an analysis and forecast of ratepayer impacts when comparing and selective alternative

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[27] $22 billion - $19.4 billion + $6.0 billion = $8.6 billion.

[28] See PG&E's RAMP Report.

[29] See PG&E's Data Request Response *RAMP-2024_DR_CalAdvocates_002-Q003*.

[30] Public Utilities Code section 451.

mitigation programs. For example, PG&E should estimate the costs of hardening the other approximately 15,000 miles of its overhead distribution system in the high threat fire district, since PG&E's focus on undergrounding only addresses approximately 8,000 miles of overhead conductor hardening.

F. PG&E should evaluate the risks from incomplete safety, reliability, and maintenance work.

PG&E's risk modeling does not explicitly connect inspections completed (or not completed) and the downstream effects on enabled risk-reducing work. Consequently, PG&E's 2024 RAMP risk modelling does not directly estimate changes in safety risk attributable to the number of inspections completed.[31]

Investigations of utility infrastructure events have identified incomplete safety and reliability work as a root cause of costly catastrophic events, such as the Zogg Fire, the Camp Fire, and the Sulphur Fire.[32], [33], [34] PG&E continues to fall behind in completing critical safety and reliability work as identified in PG&E's 2023 Risk Spending and Accountability Report (RSAR).[35]

For example, in the 2020-22 GRC cycle PG&E did not complete 15% of authorized work for its Intrusive Pole Inspections (MAT Code GAA).[36] In 2023 (the start of the 2023-26 GRC cycle), PG&E's percentage of incomplete authorized Intrusive Pole

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[31] PG&E's Supplemental Data Request Response in *RAMP-2024_DR_CalAdvocates_002-Q007* and *RAMP-2024_DR_CalAdvocates_002-Q009*.

[32] Kasler, Dale. *PG&E equipment caused deadly Zogg Fire in Shasta County. Cal Fire says tree hit power line,* March 22, 2021. The Sacramento Bee. Access at: https://www.sacbee.com/news/california/fires/article250134899.html

[33] I.19-06-015, *Motion of the Safety and Enforcement Division to Expand the Proceeding Scope to Include the 2018 Camp Fire, Appendix A, SED Incident Investigation Report for 2018 Camp Fire with Attachments,* November 26, 2019, at 16. Access at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M320/K909/320909806.PDF

[34] Van Derbeken, Jaxon. *PG&E Admits it Broke 2020 Promise to Fully Inspect 50K Poles in High Fire Risk Zones,* May 14, 2021. NBC Bay Area. Access at: https://www.nbcbayarea.com/investigations/pge-admits-itbroke-2020-promise-to-fully-inspect-58000-poles-in-high-fire-risk-zones/2545708/

[35] See *Comments of the Public Advocates Office on Pacific Gas and Electric Company's 2023 Risk Spending Accountability Report* (RSAR Comments), August 21, 2024.

[36] RSAR Comments at 6.

Inspections rose to 55%.[37] Pole failure is a contributor to PG&E's CPUC-reportable ignitions, with 28 such ignitions stemming from pole failure in the last four years.[38]

The deficits in PG&E's 2023 RSAR highlights the need for PG&E to evaluate the risks of incomplete safety, reliability, and maintenance performance to mitigate risks to the public. Completing critical safety and reliability work timely can prevent or reduce future catastrophic events.

G. PG&E should not exclude its water conveyance system as a top RAMP risk.

PG&E's RAMP Application includes some risks and excludes others that PG&E deems as less significant. Cal Advocates is concerned that significant vulnerabilities have therefore been excluded and not addressed. For example, PG&E did not explain why it excluded PG&E's water conveyance system as a component RAMP Risk.[39] News articles have reported fatalities associated with water conveyance facilities.[40] In November 2010, an 18-month-old fell to his death while walking near a PG&E canal with his stepmother. The Gold Country Media article written about the incident stated that the PG&E canal "is running swift and cold at this time of year, with little chance to get out for victims who fall in." The same article states that the 18-month-old is "the sixth [death] in an Auburn-area canal since January 2009. The bodies of the five canal victims- all adult men- were found in the Wise Canal or Wise Forebay."

Cal Advocates recommends that SPD require PG&E to supplement its RAMP Report to justify why its water conveyance system is not a significant risk to employees and the public.

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[37] RSAR Comments at 6.

[38] RSAR Comments at 13-14.

[39] PG&E's RAMP Report, Table 1-1 at Page 1-6 lists water conveyance facilities as an "Out of Scope" risk.

[40] See, e.g., Gold Country Media, *Toddler dies after falling into Placer County Canal*, November 24, 2010, access at: https://goldcountrymedia.com/news/37206/toddler-dies-after-falling-into-placer-county-canal/

III. CONCLUSION

For the reasons stated herein, Cal Advocates recommends that SPD require PG&E to supplement its RAMP Report and that SPD consider Cal Advocates' concerns in its report on PG&E's RAMP Report, as described herein.

Respectfully submitted,

/s/ **Angela Wuerth**

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October 15, 2024

APPENDIX A- DATA REQUESTS

#	Description
1	PGE Ramp-2024_DR_CalAdvocates_002-Q003
2	PGE Ramp-2024_DR_CalAdvocates_002-Q007
3	PGE Ramp-2024_DR_CalAdvocates_002-Q009
4	PGE Ramp-2024_DR_CalAdvocates_004-Q001
5	PGE Ramp-2024_DR_CalAdvocates_004-Q002Atch01

1. PGE RAMP-2024_DR_CalAdvocates_002-Q003

PACIFIC GAS AND ELECTRIC COMPANY
RAMP 2024
Application 24-05-008
Data Response

PG&E Data Request No.:	CalAdvocates_002-Q003		
PG&E File Name:	RAMP-2024_DR_CalAdvocates_002-Q003		
Request Date:	August 23, 2024	Requester DR No.:	002
Date Sent:	September 9, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	N/A	Requester:	Anna Yang

QUESTION 003

Please provide PG&E's analysis for how it quantifies the impacts of costly investments on customer rates.

ANSWER 003

PG&E did not conduct an analysis of this issue in its RAMP Report. The RAMP is not a funding request and does not evaluate the impact of investments on customer rates.

2. PGE RAMP-2024_DR_CalAdvocates_002-Q007

PACIFIC GAS AND ELECTRIC COMPANY
RAMP 2024
Application 24-05-008
Data Response

PG&E Data Request No.:	CalAdvocates_002-Q007		
PG&E File Name:	RAMP-2024_DR_CalAdvocates_002-Q007		
Request Date:	August 23, 2024	Requester DR No.:	002
Date Sent:	September 10, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	N/A	Requester:	Anna Yang

QUESTION 007

PG&E’s 2023 RSAR shows that PG&E did not complete 55% of its authorized work for Intrusive Pole Inspection (MAT Code GAA) in 2023.[5] Please provide PG&E’s analysis for how it quantifies the safety risks of not completing these inspections.

ANSWER 007

PG&E objects to use of the term “authorized work.” The correct term is “imputed adopted work”.

PG&E's risk modeling does not explicitly connect inspections completed (or not completed) and the downstream effects on enabled risk-reducing work, as this type of work is generally foundational in nature. As such, PG&E’s 2024 RAMP risk modelling does not directly reflect changes in risk attributable to completing 45% of imputed/adopted inspection work in 2023.

5 A.24-05-008, PG&E’s 2023 RSAR, Table 3-3, Line 76.

3. PGE RAMP-2024_DR_CalAdvocates_002-Q009

PACIFIC GAS AND ELECTRIC COMPANY
RAMP 2024
Application 24-05-008
Data Response

PG&E Data Request No.:	CalAdvocates_002-Q009		
PG&E File Name:	RAMP-2024_DR_CalAdvocates_002-Q009		
Request Date:	August 23, 2024	Requester DR No.:	002
Date Sent:	September 10, 2024	Requesting Party:	Public Advocates Office
PG&E Witness:	N/A	Requester:	Anna Yang

QUESTION 009

PG&E's 2023 RSAR shows that PG&E did not complete any authorized work for its Underground Manhole Inspections (MAT Code BFF) in 2023.[7] Please provide PG&E's analysis for how it quantifies the safety risks of not completing these inspections.

ANSWER 009

PG&E objects to use of the term "authorized work." The correct term is "imputed adopted work".

Underground Manhole Inspection is a foundational program. PG&E's risk modeling does not explicitly connect inspections completed (or not completed) and the downstream effects on enabled risk-reducing work. As such, PG&E's 2024 RAMP risk modelling does not directly estimate changes in safety risk attributable to the number of inspections completed in 2023.

7 A.24-05-008, PG&E's 2023 RSAR, Table 3-3, line 58 at 3-5.

4. PGE RAMP-2024_DR_CalAdvocates_004-Q001

PACIFIC GAS AND ELECTRIC COMPANY
RAMP 2024
Application 24-05-008
Data Response

PG&E Data Request No.:	CalAdvocates_004-Q001
PG&E File Name:	RAMP-2024_DR_CalAdvocates_004-Q001
Request Date:	October 2, 2024
Requester DR No.:	004
Requesting Party:	Public Advocates Office
Requester:	Anna Yang
Date Sent:	October 4, 2024
PG&E Witness(es):	N/A

QUESTION 001

In PG&E's RAMP Application, PG&E included two undergrounding proposals: M022 and A001. Please provide a justification for why PG&E selected undergrounding for each of these two mitigation proposals instead of covered conductor. In the justification, please include an explanation of all factors that PG&E considered for each proposal and how PG&E used such factors to arrive at its decision to select undergrounding instead of covered conductor.

ANSWER 001

PG&E chose undergrounding as our preferred mitigation because it provides the most wildfire risk reduction, significantly improves customer reliability, especially surrounding EPSS and PSPS outages, and provides an electric distribution system which is more resilient to the adverse impacts of climate change with deep uncertainty. Undergrounding also substantially addresses factors such as ingress/egress and tree fall-in risk, which are not mitigated by an overhead alternative. Additional considerations influencing the decision to pursue the most risk reducing mitigation include Risk Tolerance, modeling limitations, and other uncertainties affecting the analysis.

For more information on PG&E's undergrounding mitigation please see PG&E's 2023-2025 WMP: 2023-2025 Wildfire Mitigation Plan R6 (pge.com), sections 8.1.2.1 and 8.1.2.2.

5. PGE Ramp-2024_DR_CalAdvocates_004_Q002Atch01

							Program 2027-2030 $M (NPV)				Program-Risk 2027-2030 $M (NPV)				Unit of Work				Capital ($000)			
FA	Risk ID	Program Type	Program ID	Program ID (Multiple)	Program Name	MWC or MAT	[A] Total Program Cost	[B] Foundational Activity Cost	[C] Risk Reduction	[C]/([A]+[B]) CBR	[A] Total Program Cost	[B] Foundational Activity Cost	[C] Risk Reduction	[C]/([A]+[B]) CBR	2027	2028	2029	2030	2027	2028	2029	2030
EO	WLDFR	Mitigation	WLDFR-M002 (M022 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (M022 Alternative)	System Hardening [Overhead] (M022 Alternative)	08W	$ 1,695	$ -	$ 30,356	17.9	$1,695	$0	$29,570	17.4	263	316	368	421	$ 327,702	$ 405,197	$ 486,912	$ 573,165
EO	DOVHD	Mitigation	DOVHD-M002 (M022 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (M022 Alternative)	System Hardening [Overhead] (M022 Alternative)	08W	$ 1,695	$ -	$ 30,356	17.9	$1,695	$0	$786	0.5	263	316	368	421	$ 327,702	$ 405,197	$ 486,912	$ 573,165
EO	PCEEE	Mitigation	PCEEE-M002 (M022 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (M022 Alternative)	System Hardening [Overhead] (M022 Alternative)	08W	$ 1,695	$ -	$ 30,356	17.9	$1,695	$0	$0	0.0	263	316	368	421	$ 327,702	$ 405,197	$ 486,912	$ 573,165
EO	WLDFR	Mitigation	WLDFR-M002 (A001 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (A001 Alternative)	System Hardening [Overhead] (A001 Alternative)	08W	$ 2,286	$ -	$ 40,138	17.6	$2,286	$0	$39,185	17.1	400	440	480	520	$ 497,684	$ 564,574	$ 634,376	$ 707,858
EO	DOVHD	Mitigation	DOVHD-M002 (A001 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (A001 Alternative)	System Hardening [Overhead] (A001 Alternative)	08W	$ 2,286	$ -	$ 40,138	17.6	$2,286	$0	$953	0.4	400	440	480	520	$ 497,684	$ 564,574	$ 634,376	$ 707,858
EO	PCEEE	Mitigation	PCEEE-M002 (A001 Alternative)	DOVHD-M002, PCEEE-M002, WLDFR-M002 (A001 Alternative)	System Hardening [Overhead] (A001 Alternative)	08W	$ 2,286	$ -	$ 40,138	17.6	$2,286	$0	$0	0.0	400	440	480	520	$ 497,684	$ 564,574	$ 634,376	$ 707,858
PG&E's Original Proposals in the RAMP Application Below																						
EO	WLDFR	Mitigation	WLDFR-M022 (M022)	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	08W	$6,483	$ -	$ 51,321	7.9	$6,483	$ -	$50,295	7.8	400	480	560	640	$ 1,320,501	$ 1,575,164	$ 1,852,955	$ 2,139,167
EO	DOVHD	Mitigation	DOVHD-M022 (M022)	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	08W	$6,483	$ -	$ 51,321	7.9	$6,483	$ -	$1,020	0.2	263	316	368	421	$ 1,320,501	$ 1,575,164	$ 1,852,955	$ 2,139,167
EO	PCEEE	Mitigation	PCEEE-M003 (M022)	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	08W	$6,483	$ -	$ 51,321	7.9	$6,483	$ -	$6	0.0	263	316	368	421	$ 1,320,501	$ 1,575,164	$ 1,852,955	$ 2,139,167
EO	WLDFR	Mitigation	WLDFR-A001 (A001)	DOVHD-A001, PCEEE-A003, WLDFR-A001	System Hardening [Underground] (Alternative Workplan)	08W	$6,261	$ -	$ 60,724	9.7	$6,261	$ -	$59,476	9.5	400	440	480	520	$ 1,459,940	$ 1,571,705	$ 1,714,569	$ 1,861,676
EO	DOVHD	Mitigation	DOVHD-A001 (A001)	DOVHD-A001, PCEEE-A003, WLDFR-A001	System Hardening [Underground] (Alternative Workplan)	08W	$6,261	$ -	$ 60,724	9.7	$6,261	$ -	$1,240	0.2	400	440	480	520	$ 1,459,940	$ 1,571,705	$ 1,714,569	$ 1,861,676
EO	PCEEE	Mitigation	PCEEE-A003 (A001)	DOVHD-A001, PCEEE-A003, WLDFR-A001	System Hardening [Underground] (Alternative Workplan)	08W	$6,261	$ -	$ 60,724	9.7	$6,261	$ -	$8	0.0	400	440	480	520	$ 1,459,940	$ 1,571,705	$ 1,714,569	$ 1,861,676

APPENDIX B- NEWS ARTICLES

#	Description
1	Gold Country Media News Article

1. Gold Country Media News Article

Toddler dies after falling into Placer County canal

Gus Thomson, Journal Staff Writer Nov 24, 2010 11:11 AM

An 18-month-old boy died today after falling into a canal near Colfax while walking with his stepmother.

The boy - identified by the Placer County Sheriff's Office as Zachary Mather of Weimar - was found two hours after falling in at 9:30 a.m.

Zachary was discovered at a debris grate along the Hidden Valley Canal, off Peaceful Valley Road in Weimar.

Zachary's stepmother, who was not identified, told deputies that she and her stepson were walking alongside the canal in an area that was slippery and icy when both fell in. The stepmother was able to get out of the canal and neighbors who heard her yelling soon joined in the search.

"It looks to be a tragic accident," sheriff's spokeswoman Dena Erwin said.

Speaking outside Sutter Auburn Faith Hospital, where the boy had been taken after a sheriff's dive team member pulled him out of the water at about 11:45 a.m., Erwin said Zachary had been pronounced dead shortly after arriving at the North Auburn medical facility.

While early signs point to the death being accidental, an investigation had already started to determine the circumstances surrounding how the boy ended up in the water, Erwin said.

Lt. Ron Ashford of the sheriff's office said the Pacific
cold at this time of year, with little chance to get out
feet deep and about 10-12 feet wide, he said.

The water depth in the canal had been lowered by about three feet by PG&E by the time the boy was taken out of the water at the grate, about a half-mile from where he went in, Ashford said.

First aid was attempted after the boy was removed from the water. Ashford said that he didn't know if Zachary was showing signs of still being alive at that point.

The rural, residential area is located off Placer Hills Road near the Weimar Crossroads exit from Interstate 80.

Family members rushed to the hospital on a day before a holiday that normally would have been filled with celebration and thankfulness. The family was contacted through a third party and declined to talk with gathered media who had been kept from entering the building by facility security.

The death is the sixth in an Auburn-area canal since January 2009. The bodies of the other five canal victims – all adult men – were found in the Wise Canal or Wise Forebay. After the fifth death in the Auburn area, PG&E put up fencing to prevent people from slipping in along that section of canal.

Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2024 Risk Assessment and Mitigation Phase Report	Application 24-05-008 (Filed May 15, 2024)

ENERGY PRODUCERS & USERS COALITION
AND THE INDICATED SHIPPERS
INFORMAL COMMENTS ON THE 2024 RAMP REPORT

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October 9, 2024

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ENERGY PRODUCERS & USERS COALITION
AND THE INDICATED SHIPPERS
INFORMAL COMMENTS ON THE 2024 RAMP REPORT

The Energy Producers and Users Coalition (EPUC)[1] and the Indicated Shippers[2] submit these informal comments to the 2024 Risk Assessment and Mitigation Phase ("RAMP") Report ("RAMP Report") submitted by Pacific Gas and Electric Company ("PG&E" or "Company").[3]

I. INTRODUCTION

The 2024 Risk Assessment and Mitigation Phase ("RAMP") Report ("RAMP Report") submitted by Pacific Gas and Electric Company ("PG&E" or "Company") identifies the Company's top twelve safety risks, and identifies preliminary mitigation plans, and cost and benefit analyses associated with these risks. The RAMP Report is submitted in accordance with the California Public Utilities Commission's ("CPUC" or "Commission") directives, and serves as the initial phase of PG&E's 2027 General Rate Case ("GRC"). In accordance with Appendix A to D.20-01-002, the Company requests the CPUC to direct the Safety and Policy Division ("SPD") to

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[1] EPUC represents the electricity end-use interests of the following companies in this proceeding: California Resources Corp., Chevron U.S.A. Inc., PBF Holding Company, Phillips 66 Company, and Tesoro Refining & Marketing Company LLC.
[2] The Indicated Shippers represent the natural gas non-core customer interests of the following companies in this proceeding: California Resources Corp., Chevron U.S.A. Inc., PBF Holding Company, Phillips 66 Company, and Marathon Petroleum Company LP.
[3] The August 8, 2024 *Assigned Commissioner's Scoping Memo and Ruling* in A.24-05-008 indicates that intervenors' informal comments are due to the Safety and Policy Division and the 2024 RAMP service list.

review the report and close the proceeding, once the RAMP methodologies are integrated into PG&E's 2027 GRC.

A key highlight of the 2024 RAMP Report is PG&E's implementation of the Risk-Based Decision-Making Framework (“RDF”), superseding the previous Safety Model Assessment Phase (“S-MAP”) Settlement Agreement. This new framework emphasizes a Cost-Benefit Approach (“CBA”), where risks are assessed and reported in monetary terms, enhancing transparency and clarity in risk evaluation. PG&E also conducted an Environmental and Social Justice (“ESJ”) Pilot Study, aligning with the CPUC's focus on addressing equity concerns in risk mitigation.

These comments submitted by EPUC and the Indicated Shippers to the CPUC’s Safety Policy Division outline concerns with PG&E’s RAMP Report. There are several areas where PG&E’s risk assessment methodology could be improved, including: the proposed Risk Attitude Function (“RAF”), the use of Subject Matter Expert (“SME”) input, the estimation of Public Safety Power Shutoff (“PSPS”) consequences, and the application of the Department of Energy Interruption Cost Estimate (“ICE”) calculator.

II. RISK ATTITUDE[4] FUNCTION

PG&E’s proposed RAF in its RAMP Report is a mathematical function used in risk assessment to adjust the value of potential outcomes, based on PG&E’s level of risk aversion. In the context of its RAMP Report, PG&E adopted a risk-averse RAF in order to prioritize the mitigation of risks with extreme outcomes (i.e., consequences). PG&E justifies that approach by observing that catastrophic events, such as wildfires or loss of containment on gas transmission

[4] Now called “Risk Scaling Function,” per D.24-05-064.

pipelines, can have a more severe impact than multiple routine events, even if the expected loss from the routine events are the same or higher than the expected loss from the catastrophic event. In order to scale the magnitude of the risk associated with an event, PG&E developed three loss regions: routine, elevated, and catastrophic, and then assigned dollar ranges that comprise the loss regions for the gas system safety, reliability, and financial risk attributes. Depending on the level of monetized risk consequences associated with an event, the risk attribute value will then be scaled by a factor of either 1, 2.5, or 7.5, depending on whether the value falls into either the routine, elevated, or catastrophic region, respectively.

There are several other aspects of the proposed RAF that warrant SPD's attention. First, the application of a risk-averse RAF should not become an excuse for ignoring or otherwise not managing routine risks with higher frequency of occurrence. Using an RAF as a risk premium multiplier to amplify the financial consequence of low-probability but high-consequence risk events will shift priorities toward investments that mitigate extreme risk drivers or tail-risks, and will reduce PG&E's efforts directed at mitigating routine risk events. The RAF ultimately used in risk analysis should also address routine risks to identify the most economic means of mitigating public safety risks via utility resource planning.

PG&E's analysis would be better informed by using a range of risk multipliers more specifically tied to the type of catastrophic risk event. For example, for the catastrophic region of its RAF, PG&E proposes a singular Risk Premium multiplier of 7.5 based on a combination of catastrophic bond data; the spread in the underlying data was from 5.0 to 23.0, based on a mix of cyber and wildfire CAT bonds.[5] It would be inappropriate to use this Risk Premium multiplier for an event such as the loss of containment on gas transmission pipelines, since the data supporting the scaling factor are not related to that safety risk. Instead, PG&E should develop ranges of risk premium multipliers for catastrophic risk events that are more closely tied to the event type. This approach would produce a wider range of mitigation options that can be prioritized based on the event frequency and magnitude. Development of a suite of RAF curves, rather than PG&E's one-size-fits-all approach, would be preferable.

In addition, using a Risk Premium multiplier for the elevated risk region of the RAF presents similar problems to the catastrophic region. Specifically, data used to establish the elevated region Risk Premium multiplier is based on Commercial Multiple Perils policies and indicative pricing from PG&E's insurance broker. This insurance data is not relevant to all risk events occurring in the elevated region. Further, one of the purposes of using the Risk Premium multiplier is to capture risk not easily quantified. However, for the elevated risk region the financial risk will fall in the range of the utility's insurance coverage. Thus, the financial risk is known, and does not need to be elevated to capture uncertainty. It would be more appropriate to replace the singular curve with multiple curves that are more representative of the safety and reliability risk associated with each event type.

PG&E's proposed primary use of a "risk-averse" RAF should be tested to ensure it reasonably balances customers' need for affordable rates with the objective of economically mitigating ratepayer exposure to the consequences of both infrequent extreme risk events and

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[5] See PG&E 2024 RAMP Exh. PG&E-2, Risk Management, Safety and Planning, May 15, 2024 at p. 2-25 (Table 2-9).

more frequent routine risks. In D.24-05-064, the Commission adopted revisions to the RDF requiring each utility presenting a risk-averse risk RAF to also present a risk-neutral (i.e., linear) RAF analysis for comparison. The Commission should require PG&E to provide that risk-neutral RAF analysis to SPD, so that SPD can assess the cost-effectiveness and rate affordability impacts of PG&E's proposed risk-averse RAF.

Recommendation #1: Request that PG&E develop and apply a suite of RAF curves for the catastrophic loss region showing the spread in risk premium multipliers for each discrete category of covered risks (e.g., cyber, wildfire, etc.), rather than adopting a singular RAF for application to all categories of risk.

Recommendation #2: Request that PG&E develop and apply a suite of RAF curves for the elevated loss region showing the spread in risk premium multipliers for each discrete category of covered risks, rather than adopting a singular RAF for application to all categories of risk.

Recommendation #3: Require PG&E to submit its RAMP analysis with a risk-neutral RAF for comparison with its proposed risk-averse RAF analysis.

III. SUBJECT MATTER EXPERT ("SME") INPUT

The use of SME input in the risk assessment process is valuable for capturing expert knowledge and judgment, especially in areas where data might be limited or uncertain. However, it is important to ensure that SME input is used transparently and consistently, and that it is adequately documented and justified. For example, in its response to EPUC/Indicated Shippers' data request 1-14, PG&E stated that it "relied on SME input to adopt the ranges for Routine, Elevated and Catastrophic losses based on orders of magnitude of the largest probable event i.e., <=1%, 1% to 10%, and > 10% respectively." PG&E provided no other detail as to the process the SMEs used to adopt these ranges, nor did PG&E substantiate the objectivity of that process. As a result, risk events may fall into the incorrect loss region due to the arbitrary nature of the thresholds selected by SMEs to establish each region.

The RAMP Report would benefit from providing more details on how SME input was developed and utilized, the specific areas where SME input was used, and the methodology for incorporating SME judgment into the risk models. Additionally, having SMEs develop inputs that directly inform the impacts of the RAF should be avoided when objective data is available. For example, data from historical events could be used to develop the appropriate delineation between the loss regions of the safety and gas reliability attributes, rather than relying on the arbitrary percentages cited above.

Recommendation #4: Require PG&E to provide detailed explanations of the processes utilized to incorporate SME judgement into the risk modeling.

IV. CONSEQUENCE OF PUBLIC SAFETY POWER SHUTOFF ("PSPS") EVENTS

The inclusion of the potential indirect safety consequences of PSPS events in PG&E's risk assessment could be a positive development that reflects a more comprehensive understanding of the impacts of PSPS. However, the methodology PG&E used for estimating these consequences, particularly the use of an exponential probability distribution based on limited data, warrants further scrutiny and refinement.

Specifically, the factors PG&E used to estimate the indirect safety impacts of PSPS and other outage events could be improved. PG&E is relying on a very small sample size of wide-spread outages (six) in various regions of the U.S. to estimate the fatality rate associated with outage events, which may not lead to statistically significant conclusions. Also, the impacts of wide-spread outage events in other geographical regions may be significantly different than the targeted PSPS events that PG&E normally employs. The majority of the wide-spread outage events used by PG&E for comparison were the result of natural disasters, not PSPS events that can often be announced in advance. Using the fatality estimates from disaster-related events in other regions as an indirect safety consequence of a PSPS event in PG&E territory may unduly prejudice consideration of PSPS as a complementary wildfire risk mitigation. Doing so may distort to the upside the safety consequences of using PSPS to mitigate risks. In its response to EPUC/Indicated Shippers' data request 1-11, PG&E admits that it did not use actual historical PSPS event information in its risk frequency and consequence calculations. This is a potential source of significant error, causing PG&E to overestimate the indirect impacts of PSPS events.

Recommendation #5: Require PG&E to utilize actual PSPS outage information to inform the impacts of PSPS events.

V. DEPARTMENT OF ENERGY INTERRUPTION COST ESTIMATE CALCULATOR

The use of the ICE calculator for estimating the economic costs of power interruptions is a reasonable approach; however, it is important to acknowledge the limitations of the calculator, and the potential need for adjustments to reflect the specific attributes of PG&E's service territory and customer base.

In particular, the ICE calculator input data for Commercial and Industrial customer classes often relies on default input data for the state of California as a whole, as opposed to using customer specific data for PG&E's service territory. Additionally, PG&E did not consider the existence and availability of backup generation for these customers when estimating the impact of outages. The financial impact of outages is likely overinflated as a result of these omissions. The RAMP Report could benefit from providing a more detailed discussion of the limitations of the ICE calculator and any adjustments made to its inputs or outputs, to ensure that the estimated costs of power interruptions are accurate and relevant to PG&E's unique territorial context.

Recommendation #6: Require PG&E to utilize PGE customer data rather than statewide averages in the ICE calculator—if not for this 2024 RAMP, then for its 2028 RAMP.

Recommendation #7: Require PG&E to provide a detailed narrative of the inherent limitations of the ICE calculator, and any adjustments made to inputs or outputs to compensate for those limitations.

VI. CONCLUSION

PG&E's 2024 RAMP Report demonstrates a commitment to enhancing its risk assessment methodology, and incorporating societal risk preferences and environmental and social justice considerations into its decision-making process. However, PG&E’s proposed RAF, its use of SME input, its estimation of PSPS consequences, and its application of the ICE calculator warrant further scrutiny and refinement by SPD to ensure a robust, transparent, and equitable risk assessment process.

PG&E should continue to engage with SPD and stakeholders to address these issues and refine its risk assessment methodology in this current and future RAMP proceedings.

Respectfully submitted,

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Consultants to the Energy Producers and Users Coalition and the Indicated Shippers

October 9, 2024

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2024 Risk Assessment and Mitigation Phase Report	Application 24-05-008 (filed May 15, 2024)

MUSSEY GRADE ROAD ALLIANCE INFORMAL COMMENTS TO THE

SAFETY POLICY DIVISION REGARDING

PACIFIC GAS AND ELECTRIC COMPANY'S RAMP FILING

REVISION 1

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Dated: October 9, 2024
Revised: October 11, 2024

1. INTRODUCTION

The Mussey Grade Road Alliance (MGRA or Alliance) submits these informal comments on the PG&E 2024 RAMP filing[1] to the CPUC's Safety Policy Division (SPD) as per the schedule set forth in the Scoping Memo.[2] These informal comments are prepared by Mussey Grade Road Alliance expert Joseph Mitchell.

MGRA along with other joint parties filed a Joint Prehearing Conference Statement[3] listing the key issues we believe should be within the scope of this proceeding. The issues that MGRA will raise within these informal comments fall within this framework.

PG&E's RAMP filing is detailed and comprehensive, and builds upon previous RAMP and GRC proceedings, years of Wildfire Mitigation Plan filings, and extensive additional guidance from both OEIS and the CPUC. Furthermore, PG&E has provided extensive worksheets and data, and has provided MGRA with extensive and sometimes detailed data requests.

The result, however, is much bigger than the sum of its parts. In fact, the new PG&E RAMP and the GRC process that follows should be regarded by SPD and the Commission not so much as an evolutionary step forward but a complete rethinking of the way that risk is going to be managed at the Commission. To a large extent this is not PG&E's doing but rather new guidelines that have been adopted through the S-MAP/RDF proceeding R.20-07-013 have had profound impacts. These arise primarily from three changes:

- The switch from Risk Spend Efficiency to Cost-Benefit Ratio
- Incorporation of PSPS risk and EPSS risk using the Lawrence Berkeley National Laboratory Interruption Cost Estimate (ICE) Calculator to determine reliability attributes.
- Incorporation of a convex risk scaling function that scales based on a 3rd party financial instrument.

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[1] A.24-05-008; APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U39M) TO SUBMIT ITS 2024 RISK ASSESSMENT AND MITIGATION PHASE (RAMP) REPORT; May 15, 2022. (RAMP)
[2] A.24-05-008; ASSIGNED COMMISSIONER'S SCOPING MEMO AND RULING; August 8, 2024; p. 4. (Scoping Memo)
[3] A.24-05-008; JOINT PREHEARING CONFERENCE STATEMENT; July 17, 2024.

The most important implication is that these changes have fundamentally altered the emphasis on "safety" that started out as the Commission's primary goal in these RAMPs. Reliability issues, mostly due to the explicit hundred-fold weighting of medium and large business customers, can be expected to play a much larger role in the GRC proposal and PG&E's upcoming SB 884 undergrounding application.

PG&E's risk-averse attitude function based on Catastrophic (CAT) bond risk premium is looked at in significant detail and found wanting. It fails to deliver on its promise of transparency, market efficiency, and reliable estimate of uncertainty. In order to salvage the risk-based framework for the GRC PG&E should be required to submit a linear weighting function alternative in its GRC. PG&E has a valid need to include uncertainty, but uncertainty predicted by the CAT bond is likely a gross overestimate. PG&E has the ability to analyze sensitivity to model parameters via Monte Carlo (particularly the cut-off parameter, which will provide the greatest variation), and even test the effect of different model types.

MGRA has been very active in SCE and SDG&E's GRC cycle and in review of the OEIS Wildfire Mitigation plans. In previous work, it was discovered that analysis of SCE field data for covered conductors unexpectedly indicates that the wildfire ignition reduction efficiency for covered conductor is double that used by PG&E (85% versus 63%). Supporting results are provided. Despite this, PG&E is planning to deploy very little covered conductor, and does not even collect data that would support future efficiency estimates. PG&E did not include covered conductor as an alternative in its RAMP, so MGRA requested it be included in alternative analysis. PG&E complied, running scenarios with covered conductor, covered conductor + DCD/EPSS, and the same scenarios only using MGRA's estimate of covered conductor wildfire ignition risk reduction (85%). MGRA's scenarios were similar to alternatives calculated during SCE's GRC, with resources allocated to undergrounding re-directed to a significant ramp up of the covered conductor program. The analysis concludes that covered conductor can be deployed far more quickly and can reduce far more risk for the same cost, especially if coupled with DCD..

Because reliability will play a larger role in future utility undergrounding plans, MGRA also performed an analysis using PG&E weather station data that shows that PSPS impacts (frequency, extent, and duration) can be reduced 2-3 fold by raising the shutoff threshold from 58 mph to 65 mph for covered conductor+DCD. An extensive analysis of weather station data with respect to

EPSS was also performed to study 1) whether EPSS FPI thresholds correlate with ground measurements in an expected manner and 2) to what degree ground measurements vary in the vicinity of a circuit segment and might add to the information used in EPSS decision-making. The analysis confirms that FPI thresholds are a reasonable proxy for ground-level conditions, and suggest a further improvement to the algorithm by adding predicted or measured weather conditions to the EPSS decision-making process for FPI=R3. Local weather variations are considerable, however. The analysis suggests exploring a data model incorporating both ground station and FPI data in decision-making processes.

Regarding the use of undergrounding as a mitigation for PSPS and EPSS, MGRA analysis also shows that due to the parameters used in the ICE 1.0 model, PSPS/EPSS reliability consequences are dominated by medium/large business reliability. Emphasis on circuits serving these customers when making covered conductor / undergrounding decisions and when making prioritization decisions could halve PSPS/EPSS reliability impacts. Analysis of reliability impacts in circuits that have already been undergrounded and that are scheduled for undergrounding by 2025 show that the costs of undergrounding have been and will be much larger than the reliability savings for most circuits.

RAMP only provides guidance for the GRC. The observations above therefore have been used to suggest PG&E data and analysis that should be performed as part of the GRC.

1.2. Work Papers

MGRA supplemental worksheets have been stored in Github at: https://github.com/jwmitchell/Workpapers/tree/main/PGERAMP24

2. RISK MANAGEMENT AND SAFETY

2.1. Enterprise Risk Management Framework

2.1.1. Risk Tolerance

The concept of “risk tolerance” is wedded to a risk reduction philosophy. In D.16-08-018 the Commission defined risk tolerance as:

Maximum amount of residual risk that an entity or its stakeholders are willing to accept after application of risk control or mitigation. Risk tolerance can be influenced by legal or regulatory requirements.[4]

PG&E adopts a “zero-tolerance” policy towards risk as one of its fundamental premises and one that it regularly turns to in its RAMP. As it states:

“…we anchor on the principle of eliminating incidents involving serious injuries or fatalities related to our assets and operations, which is consistent with PG&E’s stands that ‘Everyone and everything is always safe’ and ‘Catastrophic wildfires shall stop.’ PG&E is poignantly aware of the profound and wide-ranging impacts from low-frequency and high-consequence risk events. Accordingly, many of the work plans in this Report include mitigations that are aimed at eliminating serious safety events even when the quantitative RAMP modelling indicates the costs are higher than the modeled value of risk reduction.”[5]

While compelling slogans can help to an organization to focus on important issues (particularly those that had received insufficient attention in the past), there can be extreme repercussions when they are taken literally and without consideration of consequences. What PG&E is effectively stating is a “zero-tolerance” policy toward risk, which would be fine if they were the ones paying the cost of it, rather than the ratepayers, but they are not.

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[4] D.16-08-018,
[5] RAMP; p. 1-2.

PG&E's "anchoring" view differs from the process envisioned by the Commission when it initiated the S-MAP and RAMP processes in 2014 was "*a process that focuses on safety, assessing the risks relevant to the utility operations, and ensuring that the ratepayer-funded revenue requirement that the utility is requesting can manage and mitigate those risks <u>in a cost-effective manner</u>*."[6] (Emphasis added) The Commission has clearly and repeatedly stated that utilities must develop cost-effective wildfire mitigation.

The Commission long ago chose its position on zero-tolerance risk policies. In D.16-08-018 it stated that: "*Inherent in risk management is the unavoidable fact of limited resources and other constraints. Without resource constraints, an operator could simply apply an infinite amount of an infinite number of risk mitigation activities and the risks would be driven to zero. Clearly this is reduction of the argument to an absurdity. Therefore, risk management always assumes recognition of some constraints (rate shock, availability of trained personnel, and limitation of resources). And, optimization is always tied to risk tolerance. These concepts are all tied together*."[7]

Resolving the thorny problem of risk tolerance has been delegated to Phase 4 of R.20-07-020,[8] which is currently underway. While this is being resolved, however, there should not be an assumption that in lieu of specific Commission guidance that utilities are free to choose whatever risk tolerance definition fits their own needs.

2.1.2. Undergrounding – the Cornerstone

PG&E is not shy about the perceived place of undergrounding in its mitigation portfolio: "*The undergrounding of distribution lines is a multi-year cornerstone program to permanently reduce the Wildfire Risk, reduce PSPS and EPSS outages, and protect the grid from extreme weather events*."[9]

As established in the prior GRC, undergrounding is also the most expensive mitigation and has had a significant influence on the rate crisis facing PG&E ratepayers. For this reason, the

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[6] D.14-12-025; p. 10.
[7] D.16-08-018; p. 98.
[8] D.24-05-064; p. 67.
[9] RAMP; PG&E-1; p. 1-4.

Commission determined to approve a "hybrid" scenario that replaced a significant portion of PG&E's proposed undergrounding program with covered conductor.[10] There should not be an assumption that undergrounding should be a "default". Rather, PG&E should be able to make a showing that undergrounding is competitive from a cost/benefit standpoint with alternative mitigations for each circuit it plans to underground.

Because utilities are allowed to recover an excess of approximately 10% of the cost of capital investments, there is a perverse incentive[11] for them to choose the costliest option. PG&E makes roughly triple the profit deploying underground conductor that it does covered conductor. Sufficient evidence will be shown in these comments that PG&E has a distinct bias in favor of undergrounding and against covered conductor that is not adequately explained by analysis of technical merits.

2.1.3. Affordability Crisis Affects Customer Health and Safety

MGRA filings in the WMPs and GRCs note the correlation between customer income and longevity, and show that using simple assumptions regarding increases in rates indicate health and safety impacts from rates that may rival or exceed health and safety impacts from wildfire.[12] To date, no proceeding has adopted this position due to scoping issues or the fact that formalizing and testing this approach would take considerable effort. Neither has MGRA's assertion been effectively refuted by utilities. While MGRA's observation cannot currently be used quantitatively, the Commission should keep in mind that affordability is not an abstract concept independent of utility risk reduction. What a customer considers "risk" is much broader than their interactions with utilities, and likely includes financial, safety, and health considerations. Unbridled utility spending in search of the El Dorado of perfect risk reduction transfers risk from the customers in the wildland urban interface to those less able to pay.

[10] D.23-11-069; p. 295.
[11] The Commission illustrates its awareness of the effect of "perverse incentives" in D.16-06-054, p. 149.
[12] A.21-06-021; MUSSEY GRADE ROAD ALLIANCE OPENING BRIEF ON PACIFIC GAS AND ELECTRIC COMPANY'S 2023 GENERAL RATE CASE; November 4, 2022; pp. 5-8.

2.2. Risk Modeling and Cost Benefit Ratio

2.2.1. Safety

2.2.1.1. Outage-related safety

As noted in previous MGRA filings, for example in the previous GRC cycle, PG&E's estimates for the safety component of outage impacts are likely to be underestimates due to the indirect impacts of the outages, for example traffic accidents, evacuation impacts, communication failures, etc.[13] In its current RAMP, PG&E fully acknowledges the limitations of its outage data set (six events), and notes that "*indirect safety estimates are still uncertain even if being represented by a probability distribution because, among other things, the mean itself is uncertain (only six events had reported or estimated outage-related mortality in the literature), the true probability distribution might not be exponential distribution, and there are missing factors (e.g., natural hazards and related damage, emergency preparedness and response, proportion of vulnerable population, etc.) that influence the indirect safety consequences but the research or data is not readily available*."[14]

While the safety impacts likely remain an underestimate, with the implementation of a cost/benefit analysis, specifically one using the Berkeley ICE calculator, the calculated reliability impacts far exceed safety impacts – in fact by a factor of 100.[15] Skepticism of current use and function of the ICE calculator in this is context is warranted and will be discussed in the next section. However, concern that negative effects of PSPS and EPSS are being underestimated is no longer necessary and in fact opposite may in fact be true.

[13] A.21-06-021; MUSSEY GRADE ROAD ALLIANCE OPENING BRIEF ON PACIFIC GAS AND ELECTRIC COMPANY'S 2023 GENERAL RATE CASE; November 4, 2022; p. 57.
[14] RAMP; PG&E-2; p. 2-8.
[15] RAMP; PG&E-4; p. 1-6; Figure 1-2 gives reliability consequences from PSPS and EPSS of over 5,000, while Figure 1-3 indicates that safety consequences for PSPS and EPSS are around 60.

2.2.2. Reliability and the ICE Calculator

As PG&E explains in its RAMP:

"*The RDF Proceeding Phase II Decision requires each IOU to use the most current version of the Lawrence Berkeley National Laboratory Interruption Cost Estimate (ICE) Calculator to determine a standard dollar valuation of electric reliability risk for the Reliability Attribute.*

As shown in Figure 2-1, the main output section of the ICE Calculator produces results for three customer classes – Medium and Large Commercial and Industrial (C&I),30 Small C&I, and Residential – as well as the average results for all customer classes, weighted by the number of customers in each class…

The ICE Calculator categorizes Medium and Large C&I as customers with annual electricity usage exceeding 50,000 kWh."[16]

PG&E calculated imputed costs per Customer Minutes of Interruption (CMI) using ICE and PG&E-specific inputs, as shown in the table below.

FIGURE 2-3
$/CMI USING ICE DEFAULT DATA AND PG&E-SPECIFIC DATA

	ICE Data (California)		PG&E Data	
Sector	Cost per CMI (2016$)	**Cost per CMI (2023$)**	Cost per CMI (2016$)	**Cost per CMI (2023$)**
Medium and Large C&I	$70.37	$89.34	$61.35	$77.89
Small C&I	$5.36	$6.81	$7.87	$9.99
Residential	$0.04	$0.06	$0.04	$0.06
All Customers	**$1.53**	**$1.94**	**$2.50**	**$3.17**

Figure 1 - PG&E ICE calculations of cost per customer minute interruption (CMI) for medium and large businesses, small businesses, and residential customers.[17]

What is remarkable about this estimate compared with historical utility estimates of PSPS consequences is the fact that reliability costs are overwhelmingly dominated by medium and large business outages. Unfortunately, the "recent" version of the ICE model, ICE 1.0 was released in 2016 and does not include important factors like backup generation.[18] The utilities are collaborating

[16] RAMP; PG&E-2; p. 2-12.
[17] Id.; p. 1-16
[18] RAMP; PG&E-4; p. 2-57.

in ICE 2.0 model development, and this will include results of a backup generation survey, but the new model is not planned for use in PG&E analysis until Q1 2027.[19] This also means that PSPS risks that are currently not informed by wildfire-related risks. MGRA has made filings in a number of CPUC proceedings stating the case that current utility PSPS risk models insufficiently capture a number of elements, such as loss of communication, traffic impacts, potential for fire starts due to generator and cooking fires, and other impacts, elements that IOU analyses lack.[20] PG&E's PSPS safety risk estimate is based only on historical disasters and does not account for these factors.[21] When PG&E compares PSPS reliability risk to PSPS safety risk using its cost/benefit analysis, its estimates for reliability risk are 100 times larger than safety risks.[22] Consequently, the story of "PSPS risk reduction" is almost wholly the story of preventing risk to large businesses. To compensate for this,

"*PG&E already prioritizes some of its investments by customer types on a non-economic basis, and introducing Tranche-specific, economically-based values of Reliability from ICE could lead to unforeseen impacts. For example, in determining tranche-level impact of PSPS, customers that provide critical services like hospitals and fire stations were given a higher weighting than others based on a weighting scheme that balances myriad considerations which was comprehensively analyzed and reviewed by stakeholders*."[23]

During workshops, SPD inquired why PG&E chose to use the average $3.17/CMI rather than finer granularity.[24] PG&E provided plausible answers, portions of which are cited above. However, examination of the segment-level structure of PSPS risk shows variations that are leading to significant misallocation of resources if expensive mitigation such as undergrounding is deployed.

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[19] DR Response RAMP-2024_DR_MGRA_001-Q010.
[20] Examples are MGRA 2022 WMP Comments; pp. 85-86;
R.20-07-013; MUSSEY GRADE ROAD ALLIANCE ADDITIONAL COMMENTS REGARDING DEVELOPMENT OF SAFETY AND OPERATIONAL METRICS; March 1, 2021; pp. 1-2.
[21] RAMP; PG&E-2; p. 2-8.
[22] RAMP; PG&E-4; p. 1-6. Figure 1-2 shows PSPS total risk as 3,655 and Figure 1-3 shows PSPS safety risk as 44.
[23] RAMP; PG&E-4; p. 2-57.
[24] Id.

MGRA Data Request MGRA-01, Question 6 addressed the question of how customer types are distributed across circuit segments, and PG&E's response can be seen in RAMP-2024_DR_MGRA_001-Q006 and attached Excel spreadsheet. MGRA's request erroneously requested data for PG&E's HFRA when it intended to request PG&E's HFRA+HFTD. Nevertheless, data for PG&E's HFRA should be representative of its customer distribution with the caveat that medium and large business customers may be more likely to be found in the periphery of PG&E's HFTD, which is largely rural. MGRA is also issuing another data request to PG&E for the HFRA+HFTD data, and we would invite SPD to monitor its response. The MGRA analysis of the HFRA data calculates a number of metrics and can be found in workpaper RAMP-2024_DR_MGRA_001-Q006Atch01-CMI-jwm.xlsx.

The total number of circuit segments provided was 4,143, with a total of 415,816 customers, and estimated CMI total of $884,698, which works out to an average $2.13 CMI per customer versus the $3.17 per customer used for PG&E's tranche estimates, reflecting a higher ratio of non-business customers than in the PG&E customer pool as a whole.

Results are broken down into customer types in the table below:

Customer Type	**Segments**	**Customers**	**CMI Total**
Medium and Large Business	1,805	5,972	$465,816
Small Business	3,410	39,260	$392,600
Residential	3,651	438,031	$26,282
Total	**4,143**	**465,816**	**$884,698**
On segments without M/L	2,338	142,109	$96,893
On segments without M/L/Small	733	7,925	$476

Table 1 - Breakdown of PG&E circuit segments crossing HFRA by customer type. Total number of segments with the customer type, number of customers, and total CMI per customer type are given. Number of customers on circuits without medium/large businesses, and with no businesses are shown in the last two rows.

One would expect that the overall cost of mitigation will scale with the number of circuits mitigated, and that the benefits will scale with CMI avoided. Safety benefits will generally scale with number of customers, but critical infrastructure will also factor in in ways that are not accounted for in the tallies above. 1,805 circuits, 44% of the total, with 5,972 medium and large business customers are responsible for 53% of the total CMI costs. 142,109 customers, 30% of the total, live on the 2,338 segments without large businesses, but are responsible for only $96,893 (11%) of CMI costs, reflecting an average per customer CMI of $0.68. Similar results for small businesses were obtained but very few customers live on circuit segments without small business.

The analysis shows that circuits that have no medium or large businesses have a much lower benefit from avoided outages both in aggregate and per customer than circuits with medium or large businesses. Therefore, when selecting circuits for undergrounding mitigation for the purposes of mitigation, from a risk reduction standpoint it would make sense to restrict the selection to:

- Circuits segments required for medium and large businesses,
- Circuits segments required for critical infrastructure lacking adequate backup capacity, and
- Circuits segments required for many residential customers.

Circuit segments not meeting these criteria may still be given priority for mitigation based on their wildfire risk, but using other measures such as covered conductor + DCD/EPSS which is far more cost effective.

These are common-sense restrictions and if applied as a pre-screen would greatly improve the post-mitigation cost/benefit ratio. One might ask, because these are common-sense measures, whether PG&E is already applying them. We have the data from PG&E's underground program to date and its planned undergrounding program through 2025, and the answer is definitively "***<u>no</u>***". The analysis supporting this conclusion is found in Section 3.2.2.

Recommendations:

- Underground mitigation should be prioritized over overhead mitigation (covered conductor) only when specific criteria are met:
  - The circuit segment provides services for medium and large businesses, large numbers of residential customers, or critical infrastructure without adequate backup generation, and is significantly affected by PSPS and/or EPSS.

- The circuit segment is in an area with high safety hazard due to extreme winds, high tree fall-in probability, or where ingress and egress from populated areas in the event of wildfire would be compromised.

- PG&E should provide number of customers served and CMI per circuit segment and aggregated over its proposal in its HFTD+HFRA areas along with its GRC filing.

2.2.3. Risk Scaling

PG&E has adopted a novel method for risk scaling, adopting a "Risk Premium Multiplier" to create a risk-averse attitude in its scaling function. It defines three ranges for its risk scaling function: Routine, Elevated, and Catastrophic, where "Catastrophic" is defined as losses over $1 billion, while the Elevated range describes losses between $100 million and $1 billion.[25]

These multipliers were shown during PG&E's workshops:

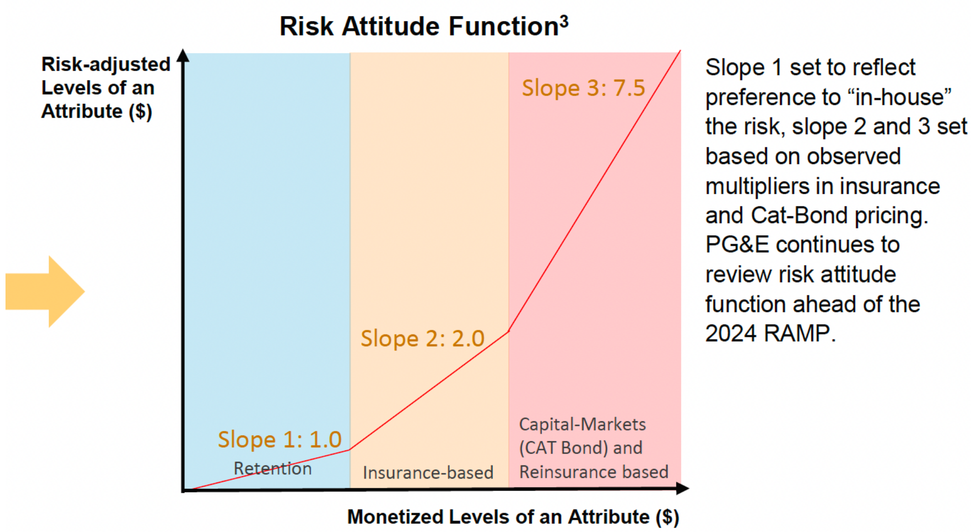

Figure 2 - PG&E's risk multipliers for different levels of consequence. Categories are Retention (<$100m), Insurance-based ($100m-$1b), and Catastrophic (>$1b).[26]

As seen in Figure 2, PG&E's risk function uses a multiplier for each attribute level. PG&E's method for obtaining its Catastrophic multiplier "*is to use available, objective data to determine the Risk Scaling Function(s). Risk Premiums/Prices from Insurance and Capital Markets meet these*

[25] RAMP; PG&E-2; p. 2-26.
[26] A.24-05-008; PG&E 2024 Risk Assessment and Mitigation Phase Workshop #1; February 7, 2024.

criteria because they are for products from independent entities that mitigate the same underlying risk presented in this Report such as wildfires, Loss of Containment (LOC) on gas pipelines, cyber-attacks, etc."[27]

2.2.3.1. CAT bonds as a risk attitude proxy

What PG&E uses for "objective data" (as opposed to the detailed analysis it has done to quantify its geographical vegetation data, ignition data, fire data, customer data, etc.) is data from the reinsurance market in the form of catastrophic (CAT) bonds.[28] Its justification for doing so is that "*Market theory tells us that the prices obtained from a perfect market maximize value to society. Of course, no market is perfectly competitive, complete, or truly representative of societal preferences—for instance, in addressing ESJ concerns—but there are established practices that can be employed within the market-based approach to account for shortcomings while still preserving its function of communicating societal values. Markets are often used to determine the fair value of goods and services, but whether one should obtain the said goods or services is dependent on individual circumstances. Hence, market data… can be used, in part, to determine the value of mitigations, and whether to fund such programs is part of the IOU's General Rate Case process, and should include budget considerations, overall priorities, risk tolerance and other factors*."[29]

This justification merits skepticism. The efficient market hypothesis defines "*a market to be 'informationally efficient' if prices always incorporate all available information*."[30] The assumption that CAT bond prices efficiently reflect risk, and do so better than PG&E itself, is only correct if the insurance companies have more complete information regarding wildfire consequences directly applicable to PG&E's circuits than PG&E itself does. Once consequence of this assumption, if it is true, is that CAT bond prices would align well with each other. PG&E lists the CAT bond prices it used to obtain its estimate:

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[27] RAMP; PG&E-2; p. 2-20.
[28] RAMP; PG&E-2; p. 2-23.
[29] Id; p. 2-21.
[30] Chen, J., Kelly, R.C., Kvilhaug, S., 2022. Informationally Efficient Market: Meaning, Hypothesis, Criticism [WWW Document]. Investopedia. URL https://www.investopedia.com/terms/i/informationallyefficientmarket.asp (accessed 10.8.24). See also: Grossman, S.J., Stiglitz, J.E., 1980. On the Impossibility of Informationally Efficient Markets. The American Economic Review 70, 393–408. https://www.jstor.org/stable/1805228

TABLE 2-9
CAT BOND DATA SUMMARY

Line No.	Issue	Risk	Date	Attachment	Coverage	Premium Multiplier
1	PG&E Cat Phoenix Re	Wildfire	Aug 2018	$1.25b	$200m	7.5
2	Sempra SD Re Ltd (series 2018-1)	Wildfire	Oct 2018	$1.326b	$125m	19
3	Sempra SD Re Ltd (series 2020-1)	Wildfire	Jul 2020	$1b	$90m	5-4 - 6.4
4	LA DWP Power Protective RE Ltd (series 2021-1)	Wildfire	Dec 2020	$125m	$50m	15 - 18
5	Sempra SD Re Ltd (series 2021-1) class B	Wildfire	Oct 2021	$1.2b	$135m	5 – 6
6	LA DWP Power Protective Re Ltd (series 2021-1)	Wildfire	Oct 2021	$125m	$30m	20 - 23
7	PoleStar Re Ltd (series 2024-1)	Cyber	Dec 2023	N/A	$140m	10.3
8	Matterhorn Re Ltd (Series 2023-1)	Cyber	Dec 2023	N/A	$50m	7.0
9	East Lan Re VII Ltd (Series 2024-1)	Cyber	Dec 2023	N/A	$150m	6.7
10	Long Walk Reinsurance Ltd (Series 2024-1)	Cyber	Nov 2023	N/A	$75m	5

Table 2 - CAT bond premium prices used by PG&E to estimate its Catastrophic Level risk multiplier.[31]

As can be seen, CAT bond prices for wildfire risk show significant variation, with premium multipliers ranging from 5 to 23. PG&E would appear to have based its own multiplier on the estimate of only one insurer – the aptly named Phoenix Reinsurance – with a premium multiplier value of 7.5. The lack of agreement on the range of reinsurance estimates is a red flag that insurers have very different methods for assessing risk, and not all of these can be "right". MGRA raised its point during the workshops: "*MGRA questioned whether markets can account for risk better than IOUs themselves, since IOUs presumably have more information about their service territories, assets and operating conditions. MGRA reasons that if market participants do not possess as much information and expertise as the IOUs, then the prices would not be an accurate reflection of risk.*

PG&E cannot comment on the level of knowledge that market participants possess but notes they have access to at least as much information as regulators and intervenors do, from PG&E's RAMP, GRC and WMP filings."[32]

This admission is noteworthy, and shows the implicit assumption PG&E makes in trusting its own risk estimate to Phoenix Reinsurance:

- That the company has an ignition probability algorithm that either uses PG&E's own results or calculates its own in a more accurate way than PG&E's,

[31] Op. Cite; p. 2-25.
[32] RAMP; PG&E-2; p. 2-61.

- That the company also performs a consequence analysis that incorporates a truncated power law distribution as PG&E's does, or uses PG&E's calculation, and
- That the company runs wildfire simulations superior to those of PG&E, incorporating PG&E's own highly customized vegetation modeling based on field observations, or uses PG&E's own calculation.

PG&E provides no evidence that any of these conditions are met, in fact it says it admits it does not know anything about how Phoenix Reinsurance calculates its premium. So the CAT bond price is a magical black box, lacking all transparency, into which PG&E can project anything it wishes. PG&E argues that this is the market, risk management is how these reinsurers make their money, so we should trust that they know their business. There is reason to be skeptical of this view.

As noted previously, the market requires knowledge, and detailed knowledge of risk is very difficult to get, as the Commission and intervenors have watched PG&E struggle over many years to build a defendable risk management framework, dedicating tremendous expense and many thousands of hours of person-time. PG&E has presented no evidence that Phoenix Re has done this. Furthermore, as MGRA discussed in depth in a filing ten years ago, when there is a small probability of loss during the tenure of an employee or manager at a company, the personal interest of the manager or employee deviates from the long-term interest of the company. Therefore, it is improper for PG&E to make the implicit assumption that the risk estimation made by a third party is superior to its own even if calculating risk is central to that party's business.

Finally, there is also the assumption in PG&E's model that the risk attitude of the insurer reflects the risk attitude of PG&E ratepayers and residents of wildfire-prone areas. This is not the case. There are areas of common interest between the insurer and ratepayer/residents: neither wants property or life losses from major wildfires. However, interests significantly diverge in a number of areas:

- Ratepayers care about the cost of their electric bill, very much so. Insurers do not.
- Residents care whether their power is reliable. No utility is being sued over reliability issues, and it is not clear whether a CAT bond issuer would be liable even if they were. It's reasonable to conclude that insurers don't care about reliability.

- People can be harmed by wildfire smoke quite far from the source. However, nobody to my knowledge has ever sued a utility over health effects of inhaling smoke from a wildfire the utility ignited. It's reasonable to conclude that insurers don't care about wildfire smoke.

2.2.3.2. Power law risk distribution versus CAT bonds

Unless the reinsurer is using PG&E's consequence model or its results, it is highly unlikely that it is modeling losses with a truncated power law, an innovation that originated with work by MGRA and tested, adopted and owned by PG&E with the encouragement of SPD. If indeed the reinsurer is not using a truncated power law model, then by using the insurer's model and its own, PG&E is double-counting the effect of extreme wildfires. Actually, it is much worse than double-counting: in double-counting things are being added together that shouldn't. In the PG&E's "market[of one]-based" risk calculation numbers are being multiplied together that shouldn't be. A truncated power law is an inherently and naturally very risk-averse function, with the great majority of risk coming from the extreme end of the model near the cutoff.[33] Hence: "*There is no explicit necessity to inject a risk scaling function in order to incorporate uncertainty properly*."[34] To apply an external multiplier on top of a truncated power-law is likely to grossly overestimate maximum risk. In this case, the consequence cut-off was set by PG&E after a sensitivity analysis to be approximately 5X the losses due to the Camp fire.[35] These were approximately $20 billion, and so the cut-off is approximately $100 billion. It is not likely that we reach this level of loss, because maximum area that can burn is reaching its limit with modern fires, thus causing a deviation from power law distribution. Nevertheless, applying a multiplier of 7.5 as PG&E does creates a potential loss of $750 billion, 37.5X the losses of the Camp fire, which strains all credulity.

PG&E claims that modification of its risk calculation is necessary to incorporate uncertainty. PG&E is correct in this claim, and MGRA's previous suggestion in R.20-07-013 was to use a

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[33] R.20-07-013; MGRA Tail Risk Whitepaper; TAIL RISK AND EVENT STATISTICS FOR UTILITY PLANNING; August 1, 2022; pp. 20-24.

[34] R.20-07-013; MUSSEY GRADE ROAD ALLIANCE REPLY TO PARTY COMMENTS ON WORKSHOP 4 AND RISK SCALING; November 13, 2023; p. 8 (MGRA RDF Workshop 4 Reply)

[35] Pacific Gas and Electric Company; "Power Law Distribution"; September 3, 2021. (PG&E Whitepaper) Available at: https://data.mendeley.com/public-files/datasets/8nds4cx88k/files/c0178e67-92fc-4ab3-9ea7-7fdcdf3b4556/file_downloaded

Monte Carlo methodology to incorporate this uncertainty.[36] Additionally, the question of how much risk premium is introduced by uncertainty has been well studied,[37] and has been estimated to be 25-40%, far from the 750% introduced by PG&E. In the same proceeding PG&E makes a detailed and seemingly plausible argument against this proposed approach based on the Central Limit Theorem.[38] PG&E cites Nassim Taleb in their correct assertion that calculations of means and estimation of uncertainty have no value for Pareto (power law) distributions, because the total consequences over time diverge as the variable (wildfire size in our case) gets larger and larger.[39]

PG&E's core argument against the MGRA position is that using a Monte Carlo method will not address *epistemic* uncertainty, i.e. the unknown unknows.[40] "The market" that PG&E assumes is an efficient risk calculator puts a 25-40% additional premium on all risk, including epistemic risk. There is only one uncertainty capable of driving much larger variations, and that is variation on a power law cut-off point.

PG&E uses a ***truncated*** power distribution, and this makes all the difference. The mean is calculable and does not diverge. What about the uncertainty? PG&E's risk calculation is very dependent on the cut-off value, since most of the risk occurs near that value. For Pareto distributions, Taleb warns that we should "fuhgetaboudit" when it comes to mean or standard deviation.[41] This warning would also apply to uncertainty, and the 25-40% discussed by Kunreuther et. al. likely applies to uncertainties with normal distributions and not to Pareto distributions. This would be a serious issue if PG&E had not already done a sensitivity analysis of the cut-off.

PG&E's analysis described in the PG&E Whitepaper describes how the cut-off value was determined, and the risk was studied as a function of the cut-off value. It concludes: "*In summary,*

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[36] Op. Cite.
[37] Kunreuther, Howard and Erwann O. Michel-Kerjan with Neil A. Doherty ... [et al.]; At war with the weather: managing large-scale risks in a new era of catastrophe; 2009; pp. 129-133.
[38] R.20-07-013; OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON WORKSHOP #4; November 6, 2023; pp. 4-10.
[39] *Statistical Consequences of Fat Tails: Real World Preasymptotics, Epistemology, and Applications (The Technical Incerto Collection), Nassim Nicholas Taleb, STEM Academic Press, 2023*; p. 149. https://arxiv.org/abs/2001.10488
[40] R.20-07-020 OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON PROPOSED PHASE 3 DECISION; May 16, 2024; pp. 11-13. (PG&E RDF Phase 3 Comments)
[41] Op. Cite; pp. 27-28.

PG&E finally considered a multiplier of 5 to strike the balance of not flattening the curve too much but also preserve the tail risk of extreme events."[42] MGRA's suggestion of a Monte Carlo method to incorporate uncertainty would be to apply a lognormal variation around the mean value of cutoff, with a width determined by SMEs, either fundamentally as an input to PG&E's Monte Carlo or as a scaling factor applied afterwards. This would incorporate uncertainties in a transparent manner that is defensible in the real world.

PG&E's argues against such an approach, noting that the Method of Moments it used for its sensitivity analysis is frowned upon by Taleb for Pareto distributions.[43] This depends on what exactly we mean by "cut-off parameter". If this is a fit value, and this appears to be how PG&E implemented it, then Taleb's admonition applies. "Cut-off" value, however, is supposed to represent a "worst case" wildfire, where basically all available connected landscape burns. During the RDF proceeding, SCE presented comparisons of 8 and 24 hour simulations (arguing that 8 hour is sufficient, which MGRA opposed), and their geospatial model clearly showed that in many if most cases very large fires are already running up against physical boundaries: built and developed environments, agricultural lands, the ocean and other water features.[44] By jumping to 5X the maximum historical visible loss, and with simulations showing that it is hard to find scenarios at much larger levels the value that PG&E picked by fit is a plausible maximum upper bound. Of course the uncertainty of this bound can be tested with PG&E's sensitivity analysis data, using the method suggested by MGRA. This reframing is consistent with Taleb's guidance, described in his book The Black Swan:

"*… we do not realize the consequences of the rare event.*

What is the implication here? Even if you agree with a given forecast you have to worry about the real possibility of significant divergence from it… I would go even further and, …state that it is the lower bound of estimates (i.e. the worst case) that matters when engaging in a policy — the worst case is far more consequential than the forecast itself. This is particularly true if the bad scenario is not acceptable."[45]

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[42] p. 16.
[43] PG&E RDF Phase 3 Comments; p. 12. Cites:
Taleb 2022; p. 34.
[44] MGRA Tail Risk Whitepaper; pp. 35-36.
[45] Taleb, Nassim Nicholas. The Black Swan - The Impact of the Highly Improbable. Second edition. New York: Random House, 2010; pp. 161-162.

In the current case, the "worst-case" – based upon physical limitations – is used as input for the cut-off parameter. We have additional knowledge: that wildfires smaller than worst-case follow a power law distribution that has been measured and parameterized. Uncertainty in worst-case can be tested using the method described.

No other uncertainty other than cut-off is likely to affect the output at the order of magnitude level, except one: wildfire smoke.

2.2.3.3. Wildfire smoke, again

Uncertainty due to wildfire smoke risk is a unidirectional dependency. PG&E's wildfire safety risk estimate is too low because it ignores wildfire smoke safety and health risks. MGRA has analyzed and discussed this risk extensively in its filings, and it has been reviewed in an OEIS workshop, but inclusion of wildfire smoke risk into OEIS or CPUC processes has been determined to be a "hard problem" and tabled by both organizations. MGRA filings have argued that regardless of the fact that a "good" model of wildfire smoke exposure is beyond current capabilities, that the approximation introduced by SDG&E using more up-to-date references would be "less wrong" than ignoring what is almost certainly a very substantial source of risk. The approximate approach yields a correction of one fatality per 1,000 to 10,000 acres burned.[46]

2.2.3.4. Perverse incentive

Finally, bias that PG&E might have regarding its choice of risk calculation methodology should be discussed. As has been previously mentioned, PG&E can maximize its profit by choosing the most expensive capital mitigation. Much of the rest of these comments relate to choice of mitigation to reduce wildfire risk. However, the introduction of the cost/benefit ratio (CBR, and more properly benefit/cost ratio) introduces a precondition for a mitigation. In order to have a reasonable argument for mitigation, CBR must be greater than 1.0. According to PG&E's proposal, CBR for undergrounding is 13.[47] If the cost is inflated by a factor of 7.5 (as would be all

[46] MUSSEY GRADE ROAD ALLIANCE COMMENTS ON 2022 WILDFIRE MITIGATION PLANS OF PG&E, SCE, AND SDG&E; April 11, 2022; pp. 47-50. (MGRA 2022 WMP Comments)
[47] DR Response RAMP-2024_DR_SPD_015-Q001, refers to:
MGRA Workpaper RAMP-2024_DR_SPD_015-Q001_804549Atch01_804550-Secondaries-jwm.xlsx

other mitigations), then CBR is reduced to 1.7. The argument for using an undergrounding mitigation in preference to other mitigations that have higher CBR, as PG&E does, is severely compromised by this rescaling, as individual circuits will be more likely to have undergrounding CBR less than 1.0.

PG&E's proposal gets even weaker. In this GRC cycle, PG&E proposes substantial mileage of secondary lines and service drops. SPD Data Request 15 Q1 addressed this issue and PG&E responded with a file published as an MGRA workpaper called MGRA Workpaper RAMP-2024_DR_SPD_015-Q001_804549Atch01_804550-Secondaries-jwm.xlsx.[48] PG&E's CBR for secondary lines is 9.4, and if this is reduced by 7.5X the CBR hovers over 1.0 at 1.3. However, PG&E's CBR estimate for service drops is only 2.4, and if rescaled this would be only 0.3 – far below the breakeven CBR of 1.0. Therefore, it is only the risk rescaling by PG&E's risk-averse multiplier that makes this effort viable, in the sense it is in the public interest. PG&E's proposed service drop program cost is $750 million. The cost for secondaries is $135 million. Nearly $1 billion in capital costs (almost $100 million in profit for PG&E) is totally dependent on PG&E's risk scaling function. There is a strong perverse incentive for PG&E to try to amplify its wildfire risk.

2.2.3.5. Risk scaling conclusion

The original MGRA position regarding PG&E's "market based" CAT bond proposal was skeptical but open to seeing what PG&E's proposal entailed.[49] Having now examined PG&E's RAMP filing and data request responses, it is necessary to reach the conclusion that PG&E has not provided sufficient information supporting its proposal, and that information which it has provided tends to discredit its proposal. PG&E's new risk scaling function has a number of critical flaws:

- The wildfire CAT bond market is extremely small and its risk premium estimates vary substantially,

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Note: PG&E RAMP tables and data request responses list two different CBR values for undergrounding, one ~8 and another ~13. This was late-discovered in the analysis, and SPD should apply whichever that it has determined is the value currently supported by PG&E. PG&E doubtless will clarify in its comments as well.

[48] Id.

[49] MGRA RDF Workshop 4 Reply; p. 5.

- The "market" for wildfire CAT bonds is extremely illiquid and likely to lack information, explaining some of this variability,
- PG&E appears to be basing its risk scaling function on only one CAT bond,
- Neither PG&E, the Commission nor any stakeholder has visibility into how risk premium is determined by the reinsurer,
- Unless the reinsurer is using PG&E's risk estimates as the basis of its risk premium, it is extremely unlikely that its risk estimation is anywhere near that developed by PG&E, and therefore it may be no more than an educated guess,
- Unless the re-insurer is using a Pareto risk distribution for wildfire, a bespoke approach that does not seem to be yet in use outside of PG&E and SDG&E, or unless PG&E itself has abandoned the Pareto approach to consequence modeling, the use of a risk multiplier to amplify the predicted wildfire risk is entirely inappropriate and would lead to estimated losses up to $750 billion. (Reminder, that is indeed a 'b'.)
- Classical estimates for uncertainty premium range from 25-40%, whereas PG&E's uncertainty premium is 650%.
- Even allowing for the fact that an uncertainty premium for a Pareto distribution should be significantly higher than classical estimates, PG&E has a transparent way to estimate this premium using the sensitivity analysis it performed for its consequence cap, currently set to 5X the losses of the Camp fire.
- PG&E has a significant perverse incentive to amplify risk, because it is proposing a nearly $1 billion undergrounding program for secondary and service drops that would not meet the criterion of a favorable CBR.

PG&E's new risk averse scaling approach is patently inferior to its existing risk calculation, which was developed over many years at great effort and expense, and thoroughly vetted by stakeholders. For PG&E to arbitrarily multiply its risk by a number that neither it nor stakeholders understands undoes much of that work and compromises the goal of creating a CBR, which is intended to calculate risk in terms of cost. PG&E needs to incorporate uncertainty, but it can do so using the sensitivity analysis it has already done for cut-off threshold.

Intervenors, particularly TURN, have been pushing for linear risk scaling, and to at least have a reference with linear risk scaling to compare to any new model. The Commission, so far, has not been ready to intercede on this issue. However, given the state of PG&E's new risk scaling it is imperative that the Commission ensure that there is a transparent model available for comparison and potentially for use.

Recommendations:

- PG&E's GRC application should not be considered unless it includes calculation of CBR assuming linear risk scaling.
- PG&E's GRC application should not be considered unless it provides additional information supporting its use of the Phoenix Reinsurance bond and showing that the risk premium of this bond is based on quality risk analysis that is as good as or better than PG&E's risk analysis. This showing must indicate whether the CAT bond is using a Pareto distribution for wildfire loss estimates, and whether PG&E itself continues to use its Pareto based consequence model.
- PG&E should incorporate uncertainty into its risk calculation through a mechanism other than the CAT bond. The suggested mechanism is to use the function derived from PG&E's consequence cap analysis to provide the basis for a Monte Carlo varying around the 5X Camp fire value using a lognormal distribution with deviation suggested by SMEs.
- PG&E should adopt SDG&E's methodology for approximating wildfire smoke impacts, and use current references which have an imputed risk per acre burned of between 1,000 and 11,000.

3. ELECTRICAL OPERATIONS – WILDFIRE, PSPS, AND EPSS

3.1. Assumptions – Covered Conductor versus Undergrounding

Covered conductor has been extensively deployed by Southern California Edison, and has led to an extremely rapid and significant drop in wildfire risk, as shown in the figure below.

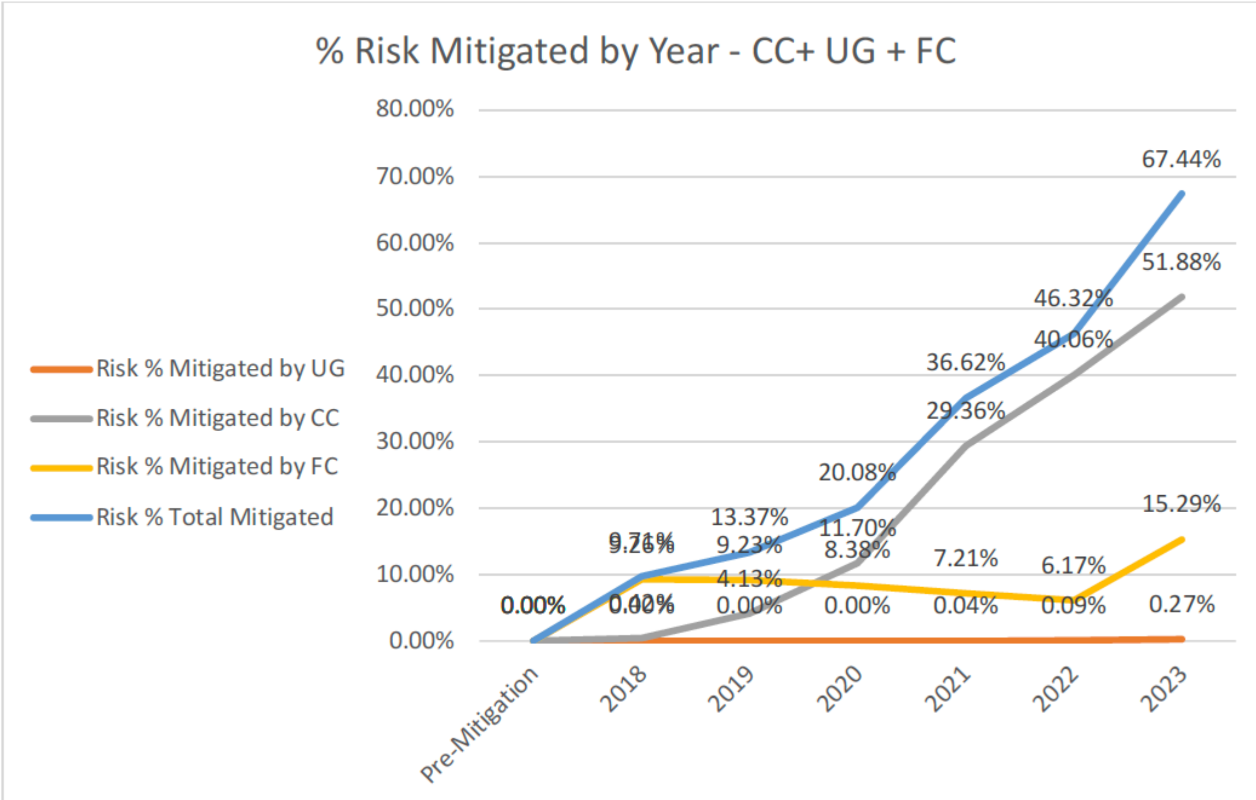

Figure 3 - SCE MARS estimated risk reductions from 2017 to 2023 broken down into covered conductor, undergrounding, fast curve, and total.[50]

Despite being required to construct a "hybrid" model consisting of both covered conductor and undergrounding in Decision 23-11-069,[51] PG&E's current RAMP essentially treats covered conductor as a non-entity in favor of its "cornerstone" undergrounding program. This is evidenced by the following: ***In its 875 page RAMP report, PG&E uses the phrase "covered conductor" only six times***. It was not included in its alternative mitigations, which MGRA remedied by requesting sensitivity analysis for covered conductor scenarios.[52]

SCE's substantial long-term deployment of covered conductor has allowed it to collect substantial field data including ignitions and wires down. This data has been analyzed over the last few years in a number of MGRA filings, allowing the strong conclusion to be reached that the ignition reduction efficiency of covered conductor is being underestimated by the IOUs by approximately a factor of 2.

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[50] A.23-05-010; MUSSEY GRADE ROAD ALLIANCE OPENING BRIEF ON SOUTHERN CALIFORNIA EDISON'S 2025 GENERAL RATE CASE; p. 44 and cited references. (MGRA SCE GRC Brief)
[51] p. 295.
[52] DR Responses RAMP-2024_DR_MGRA_001-Q011-Q013

3.1.1. Covered Conductor Wildfire Risk Reduction – Edison Data

The following data were presented in MGRA's filings in SCE's general rate case.[53] The workpaper is posted at GitHub.[54]

	2019	2020	2021	2022	2023	**Total or Wtd Avg**
Bare Wire Reportable Ignitions	37	49	46	36	15	**183**
Covered Conductor Reportable Ignitions	0	1	2	5	3	**11**
BW Ignitions / mile-yr	0.0040	0.0058	0.0065	0.0063	0.0033	**0.0052**
CC Ignitions / mile-yr	0.0000	0.0007	0.0007	0.0012	0.0005	**0.0008**
Reduction %		87.2%	89.3%	81.5%	83.6%	**85.0%**
Expected CC ignitions	1.5	7.8	18.7	27.0	18.3	**73.3**

Table 3 - Analysis of Southern California Edison field data of reportable ignitions on bare wire and covered conductor circuits for the period 2019 to 2023.

The significance of this data is explained in MGRA's SCE GRC Brief:

"*As can be seen, over the 2019 to 2023 period the mean number of ignitions observed in SCE' HFRA on covered conductor per unit mile deployed was 85.0% less than the number of ignitions observed on unhardened bare wire, significantly more than the 72% predicted by SCE. This is a factor of two fewer ignitions than SCE predicts (15% versus 28%). In fact, given the observed number of events it is possible to put a 95% confidence level at 75.3% reduction, thus indicating that the deficit in observed ignitions is a statistically significant deviation from SCE's 72% prediction.*[55]

<u>This is a big deal.</u>" (emphasis ours)

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[53] A.23-05-010; MUSSEY GRADE ROAD ALLIANCE OPENING BRIEF ON SOUTHERN CALIFORNIA EDISON'S 2025 GENERAL RATE CASE; July 15, 2024; p. 50. (MGRA SCE GRC Brief)
[54] https://github.com/jwmitchell/Workpapers/tree/main/SCEGRC25
MGRA Workpapers 2-1.a-f_MGRA-SCE-002_Q2-CCUG-WD-Ign-jwm.xlsx
[55] MGRA SCE GRC Brief; Footnote 155, cites:
MGRA-01E; p. 68; fn. 137. Explains and Cites:
There were 11 ignitions observed on covered conductor segments, with 73.3 predicted based on the bare wire ignition rate. Assuming Poisson statistics, the single-tail 95% confidence interval was calculated using the Excel formula CHISQ.INV.RT(0.05,2*(D15+1))/2, where D15=11. This gives an upper limit of 18.2 events, and 18.2/73.3 = 75.3%. See:
MGRA Workpaper 2-1.a-f_MGRA-SCE-002_Q2-CCUG-WD-Ign-jwm.xlsx, Tab 'CL Stats'.

PG&E has much less covered conductor deployed, and therefore much less field data. Nevertheless, as part of this analysis equivalent data was unsuccessfully requested through the data request process. PG&E's responses are nevertheless illuminating.

3.1.2. PG&E Does Not and Does Not Intend to Provide Covered Conductor Field Data

PG&E was presented with a data request equivalent to that presented to SCE which resulted in the data analysis shown in the previous section. PG&E's response did not provide any attribution of number of wires down or ignitions to bare wire or covered conductor segments.[56] Its reasons for not providing this data appear to be that "*first responders do not record whether the fault involved covered or bare conductors*",[57] a bizarre response considering that PG&E collects its own ignition data and does not depend on first responders.

MGRA is also participating in the review of PG&E's 2025 WMP Update. OEIS has recently released its Draft Decision on PG&E's plan, which calls for additional field data collection by PG&E.[58] MGRA called for this request to be further defined and enhanced due to PG&E's apparent bias in favor of undergrounding.[59] In PG&E's response, it explains and defends its decision not to put significant effort into tracking covered conductor field data. This is quoted at length below:

"*PG&E should not be required to continue to submit field data as part of ACI PG&E-23-05, as proposed by the Mussey Grade Road Alliance (MGRA), for two reasons.*

First, Energy Safety's draft decision already requires PG&E and the other utilities to submit "in-field observed effectiveness" data as part of ACI PG&E-23-06. In compliance with ACI PG&E-23-06—the Continuation of the Grid Hardening Joint Studies—PG&E continues to participate in

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[56] DR Response RAMP-2024_DR_MGRA_001-Q004.

[57] DR Response RAMP-2024_DR_MGRA_001-Q003.

[58] OEIS Docket 2023-2025-WMPs; OFFICE OF ENERGY INFRASTRUCTURE SAFETY; DRAFT DECISION; 2025 PACIFIC GAS AND ELECTRIC COMPANY 2025 WILDFIRE MITIGATION UPDATE; August 29, 2024; p. 24. https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=57273&shareable=true

[59] OEIS Docket 2023-2025-WMPs; COMMENTS ON THE OFFICE OF ENERGY SAFETY INFRASTRUCTURE DRAFT DECISION ON PACIFIC GAS AND ELECTRIC COMPANY 2025 WILDFIRE MITIGATION PLAN UPDATE ON BEHALF OF THE MUSSEY GRADE ROAD ALLIANCE; September 18, 2024; p. 7. https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=57378&shareable=true

the Joint IOU Covered Conductor Effectiveness Study to better understand the advantages, operative failure modes, and current state of knowledge regarding covered conductor. Based on the latest update using data through 2022, the estimated effectiveness of covered conductor is 64%. This is consistent with the previous results that were completed using data through 2020. For reference, please refer to the Joint IOU Covered Conductor Working Group Report, which was submitted to Energy Safety as an attachment to PG&E's 2023-2025 Base WMP on March 27, 2023.8 Per ACI PG&E-23-06, PG&E will continue to collaborate with the other IOUs to evaluate various aspects of grid hardening and will provide an updated Joint IOU Grid Hardening Working Group Report in the 2026-2028 WMP.

Second, MGRA's argument is based on an inaccurate representation of the current field data (by which PG&E understands MGRA to mean ignition data). Although MGRA claims that current field/ignition data shows an effectiveness higher than 64%, the current ignition data on covered conductor is not appropriate for conducting a meaningful calculation, including effectiveness or statistical significance testing, because the locations where covered conductor has been installed (often in fire-scarred rebuild areas, and areas with low tree strike risk) are not representative of PG&E's overall High Fire Threat District (HFTD) and High Fire Risk Areas (HFRA)). In addition, the data compares newly installed covered conductor to assets and equipment that are not new, and thus, results in an apparent effectiveness that may be unrealistically high. Weathering has a long-lasting, degrading impact on the risk-reduction effectiveness.

Therefore, to accurately compare ignition risk from covered conductor and bare overhead systems, it is estimated to require at least 8 to 10 years of weathering for a reasonable comparison to be made. Given these issues, Energy Safety should neither accept MGRA's argument nor revise its decision to require PG&E to continue to submit field data as part of ACI PG&E-23-05."[60]

Addressing PG&E's arguments:

- *The Joint IOU Covered Conductor Effectiveness Study found covered conductor wildfire ignition effectiveness of 64%.*
  As discussed in a number of previous MGRA filings, the Joint IOU Covered Conductor Effectiveness Study is based on SME estimates and lab testing results, not field data. The SCE result for ignition field data is anomalous but statistically

[60] OEIS Docket 2023-2025-WMPs; Reply Comments of Pacific Gas and Electric Company to the 2025 Wildfire Mitigation Plan Update Draft Decision; September 30, 2024.

significant. Other data, including outages and SCE wires down data, are consistent with the IOU estimates.

- *PG&E's current covered conductor deployment locations are not representative of PG&E's HFTD and HFRA areas and would lack sufficient statistical significance.* This is true but does not constitute a justification for not collecting data as PG&E's covered conductor deployments go forward. PG&E's service area is also not identical to that of SCE,[61] so it is important that it collect data representing its own territory.
- *Weathering will degrade covered conductor effectiveness over time, so a period of 8-10 years needs to elapse before an effective comparison can be made.*
  The effect of weathering has currently not been measured. However, SCE began deploying covered conductor on a wide scale in 2019. If there is a weathering effect it should first appear in the SCE data. It should be noted that covered conductor used by SCE includes an outside a layer of high density polyethylene (XL-HDPE) that is resistant to abrasion, tracking, and UV.[62]
  Additionally, if a period of 8 to 10 years needs to pass before covered conductor can be validated to the satisfaction of PG&E, PG&E will have completed the majority of its undergrounding program so the study would be moot.

3.1.3. CC Conclusion

PG&E does not like to talk about covered conductor, does not want to consider covered conductor, and has no plans to deploy covered conductor to any extent beyond that mandated by the Commission or required by technical limitations on undergrounding. It mentions covered conductor only six times in its RAMP filing, and did not include covered conductor in its list of alternative mitigations. It has no plans to collect or analyze covered conductor ignition data to revise its effectiveness estimates. PG&E's position may be biased by the significant perverse incentive it has to favor more expensive capital solutions. Hence it will likely be the Commission's job to enforce any serious review of covered conductor by PG&E, and to require PG&E to deploy covered conductor to the extent technically and economically warranted, as it did in D.23-11-069.

[61] DR Response RAMP-2024_DR_MGRA_001-Q013.
[62] A.23-05-010; SCE Testimony SCE-04 Vol. 05 Pt. 2A; p. 33.

Recommendations:

- Collection of field data, including ignition and wires down, and association of these incidents with the kind of conductor on which the fault occurred, must be a prerequisite for the approval of the GRC.
- PG&E should be required in the GRC to include covered conductor and DCD as one of its alternative mitigations. MGRA requested that PG&E provide an analysis of covered conductor only for RAMP and it has done so in DR Response RAMP-2024_DR_MGRA_001-Q011.
- In lieu of statistically significant or representative field data, SCE field data should be considered representative of covered conductor deployments. PG&E should be required in the GRC to include the ignition reduction effectiveness determined by SCE field data in its comparative analyses that include covered conductor.

3.2. Undergrounding

3.2.1. Comparison of Undergrounding and Covered Conductor – PG&E

As previously noted, PG&E did not include covered conductor as one of its alternative mitigations in its RAMP filing. MGRA therefore requested that PG&E provide additional cost/benefit analysis of several covered conductor scenarios. Despite its objection to some of MGRA's premises PG&E provided this analysis in its Data Request Responses RAMP-2024_DR_MGRA_001-Q013.

The MGRA scenarios are based on a concept that it originally raised in the SCE GRC. SCE's GRC proposal's basic premise was that its covered conductor program would be quickly ramped down and replaced with undergrounding for most of its remaining infrastructure. SCE's proposal would have left a significant fraction of its HFRA unaddressed in the 2025-2028 timeframe. MGRA requested that SCE analyze the following alternative: that the total amount of undergrounding be reduced by 2/3, and that SCE instead continue its covered conductor program until its entire HFTD+HFRA was hardened, which it has the capability to do based on its proven rate of covered conductor deployment.[63] This results in a solution that is equivalent in risk buydown but $1 billion less expensive than SCE's proposed solution. Additional details are presented in the next section.

The PG&E proposal presented in its RAMP for capital expenditures is summarized below:

Mitigation	ID	Miles	Cost ($M)	Risk Reduction	RR/Mile	CBR
Covered Conductor	DOVHD-002	360	449	7,987	22.2	17.8
Undergrounding	DOVHD-022	1,711	6,483	51,323	30.0	7.9
Total		2,071	6,932	59,310	28.6	8.6

Table 4 - PG&E RAMP proposal for overhead (covered conductor) and undergrounding summed over the 2027-2030 period. Risk reduction is in $M per unit and CBR is the unitless cost/benefit ratio (actually benefit to cost ratio, larger numbers imply greater efficiency).[64]

PG&E acknowledges that covered conductor can be deployed with a significantly higher benefit/cost ratio (which is misnamed CBR, Cost Benefit Ratio). According to PG&E's estimates, undergrounding reduces 35% more risk per unit mile than covered conductor. However, it is significantly more expensive, with a total cost of $6.5 billion over 4 years.

In MGRA's sensitivity analysis, the following alternative was suggested:

For covered conductor (overhead hardening, miles):

Year	2027	2028	2029	2030	
Miles	800	800	800	800	Total: 3200

Table 5 - MGRA base case for covered conductor deployment, MGRA DR 1, Q11.

For undergrounding (miles):

Year	2027	2028	2029	2030	
Miles	200	200	200	200	Total: 800

Table 6 - MGRA base case for underground deployment, MGRA DR 1, Q11.

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63 MGRA SCE GRC Brief; pp. 61-68.

64 RAMP; PG&E-4; pp. 1-89 (Table 1-24), 1-95 (Table 1-26).

Note: PG&E RAMP tables and data request responses list two different CBR values for undergrounding, one ~8 and another ~13. This was late-discovered in the analysis, and SPD should apply whichever that it has determined is the value currently supported by PG&E. PG&E doubtless will clarify in its comments as well.

PG&E responded with the estimates below in Data Request Response RAMP-2024_DR_MGRA_001-Q011:

Mitigation	ID	Miles	Cost ($M)	Risk Reduction	RR/Mile	CBR
Covered Conductor	DOVHD-A11O	3,200	3,993	62,439	19.5	15.6
Undergrounding	DOVHD-A11U	800	2,019	15,678	19.6	7.9
Total		4,000	6,012	78,117	28.6	13.0

Table 7 - Summary of PG&E Data Request Response RAMP-2024_DR_MGRA_001-Q011. RR/Mile is a calculated field, and should not be the same for undergrounding and covered conductor.

The results in Table 7 are not consistent with PG&E's RAMP value. The MGRA calculated value Risk Reduction per Mile is identical for covered conductor and undergrounding, and this is not correct. Additionally, the calculated cost per unit mile is only $2.5 million in Table 7 but $3.8 million in PG&E's RAMP tables. Assuming the data request result is in error,[65] we can derive corrected values assuming that risk reduction per mile and CBR are the same as in PG&E's RAMP presentation.

Mitigation	ID	Miles	Cost ($M)	Risk Reduction	RR/Mile	CBR
Covered Conductor	DOVHD-A11O	3,200	3,993	62,439	19.5	15.6
Undergrounding	DOVHD-A11U	800	**3,053**	**24,120**	**30.0**	7.9
Total		4,000	**7,046**	**86,559**	**21.6**	**12.3**

Table 8 - Correction of Table 5 using undergrounding RR/mile of 30.0 and CBR of 7.9.

This combination of mitigations would be approximately the same cost as the PG&E solution but would harden an additional 1,500 miles of conductor and reduce 46% more risk. SCE has demonstrated that it can install up to 1,400 miles of covered conductor per year once it ramped up its production,[66] so 800 miles per year is achievable. This also demonstrates that if a $7 billion cost is too burdensome for ratepayers and was scaled back to achieve the same risk reduction proposed in PG&E's RAMP, the equivalent cost would be $4.8 billion.

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[65] MGRA is submitting additional data requests to clarify this issue prior and will incorporate results into its filed comments.

[66] MGRA SCE GRC Brief; p. 48.

MGRA also requested the same scenario as Q11, but with EPSS/DCD enabled.[67] The results, corrected as in Table 8, are shown below:

Mitigation	ID	Miles	Cost ($M)	Risk Reduction	RR/Mile	CBR
Covered Conductor	DOVHD-A12O	3,200	3,993	71,871	22.5	18.0
Undergrounding	DOVHD-A11U	800	**3,053**	**24,120**	**30.0**	7.9
Total		4,000	**7,046**	**95,991**	**24.0**	**13.6**

Table 9 - MGRA alternative from DR1-Q12 using undergrounding RR/mile of 30.0 and CBR of 7.9.

As discussed in Section 3.1.1, MGRA's analysis of SCE field data indicates a wildfire ignition reduction effectiveness of 85%. MGRA DR-1, Q13 requests that PG&E run an additional scenario identical to Q12 but using 85% wildfire reduction effectiveness for covered conductor. Results are shown below, with corrections for undergrounding as per Table 6:

Mitigation	ID	Miles	Cost ($M)	Risk Reduction	RR/Mile	CBR
Covered Conductor	DOVHD-A13O	3,200	3,993	78,421	24.5	19.6
Undergrounding	DOVHD-A11U	800	**3,053**	**24,120**	**30.0**	7.9
Total		4,000	**7,046**	**102,541**	**25.6**	**14.6**

Table 10 - MGRA alternative from DR1-Q13 using undergrounding RR/mile of 30.0 and CBR of 7.9. Covered conductor wildfire reduction efficiency assumed to be 85%.

The results, using a covered conductor efficiency consistent with field measurements, show that risk reduction is appreciably increased, and is 73% higher than PG&E's RAMP scenario. If total risk reduction is held to that suggested in the PG&E RAMP scenario, total hardening costs would be $4.1 billion, 59% of PG&E's cost estimation. There is a slight inconsistency in PG&E's result. If undergrounding wildfire reduction efficiency is 99%, and 85% efficiency is assumed for covered conductor, then risk reduction per mile should be 85/99 X 30 = 25.8, while that calculated by PG&E is 24.5. This is not a significant difference given the uncertainty in the risk calculations.

In terms of overall wildfire risk reduction in the case of a finite budget, deployment of covered conductor provides a means to reduce risk far more efficiently than undergrounding. While undergrounding provides more risk reduction per mile than covered conductor, using a value for

[67] DR Response RAMP-2024_DR_MGRA_001-Q011

covered conductor based on wildfire risk reduction efficiency that is measured in the field makes this improvement incremental. In the case where there was a limited amount of infrastructure in high risk areas, one could argue (as PG&E does) that the completeness of protection due to undergrounding definitively removes risk from mitigated circuits. If PG&E wildfire risk were driven by the residual risk after mitigation this might be an argument to be considered, but it isn't. PG&E wildfire risk is currently driven by the overall exposure of unmitigated overhead conductors to wildfire ignition hazards, and this will be so until well after 2030. PG&E's upcoming undergrounding application under SB 844 will likely request additional underground mitigation after the current application concludes, but it will still be limited by the overall speed at which it can deploy undergrounding and the cost its customers can bear. Covered conductor can be deployed far more quickly (though PG&E has been reticent to try) and therefore can reduce far more risk for the same cost in a given period of time. At some point in the future, the incremental superiority of undergrounding in terms of risk reduction per mile would surpass covered conductor, but including DCD/EPSS and higher measured wildfire risk reduction for covered conductor pushes that date further into the future. Overall costs, and the impact they can have on customer health, safety, and well-being would be far less.

The remaining argument for undergrounding in preference to covered conductor is the necessity of EPSS and PSPS to manage severe wildfire hazard conditions for overhead lines. In this regard, undergrounding has a distinct advantage. Additionally, risk from EPSS and PSPS themselves according to PG&E's estimates using the ICE model now make up the largest contribution to residual risk. However, using undergrounding to address these issues will be shown in the following section to be highly inefficient. In subsequent sections the question of how to reduce EPSS and PSPS hazards through measures such as increased wind gust thresholds for shutoff for mitigated lines is addressed.

Recommendations:

- PG&E should provide updated analysis of alternative mitigations along as part of its GRC application that include scenarios 1) including covered conductor and DCD/EPSS, 2) assuming higher wildfire mitigation efficiency for covered conductor consistent with field observations.

3.2.2. Undergrounding as PSPS Mitigation – Results and Plans

Undergrounding is an effective way to eliminate power shutoff consequences resulting from extreme weather, assuming that all segments and circuits upstream of a mitigated circuit are similarly mitigated. Its cost effectiveness is a different matter. MGRA performed an analysis for PG&E's 2025 WMP Update that studied this question using data provided by PG&E and found that the manner in which it is being planned and executed is highly inefficient.

At issue is how much undergrounding costs compared to the benefits in reliability improvements. This varies dramatically from circuit to circuit. Because much of PG&E's HFRA is in rural and lightly populated areas, the number of customers per circuit can be low, and the circuits long. Undergrounding on such circuits can be very expensive per customer and per CMI. To measure this MGRA calculated two metrics: The first was an "counterfactual" metric based on number of customers per circuit that would pay for off-grid customer solutions if cost per customer exceeded $60k. The other metric is the cost to reduce 1 minute of PSPS time through an undergrounding solution using both customer and historical PSPS data. The results are shown below:[68]

	PG&E 2023 Data	P&E 2025 Projection
Projected cost	$1.18 billion	$3.4 billion
Customers	31,399	18,640
Cost / Customer	$42,689	$87,811
Savings at $60 k Off-Grid cutoff	38%	56%

Table 11 - Cost per customer for PG&E underground segments completed in 2023 and slotted for completion by 2025. Counterfactual potential savings from "off-gridding" customer segments costing more than $60k per customer is also shown.

The first set of data presented is from PG&E's estimated cost of undergrounding completed by the end of 2023, which includes number of customers per circuit. The cost to prevent a customer PSPS-minute is calculated per circuit segment and shown in the graph below:

[68] MGRA 2025 WMP Comments; pp. 27-49 and,
Workpaper data taken from MGRA 2025 Update Workpapers
https://github.com/jwmitchell/Workpapers/tree/main/WMP25

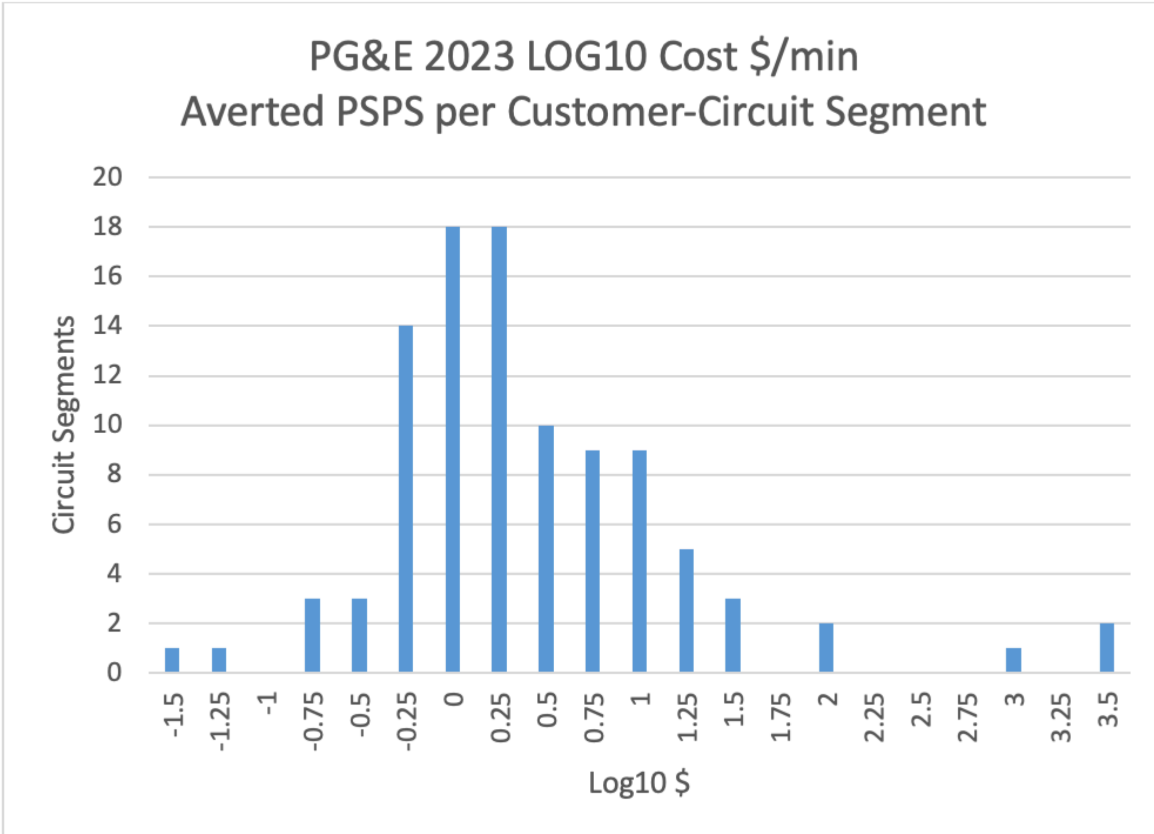

Figure 4 - Cost per avoided PSPS minute for each grid segment in the PG&E 2023 undergrounding program. The scale is logarithmic.

The scale in Figure 4 is logarithmic, and the range varies by 5 orders of magnitude (a factor of 100,000). The majority of circuits fall between $1 and $10 per minute of avoided outage per customer per year. The cost per CMI calculated by the ICE model is $3.17,[69] which seems to imply that undergrounding is a cost-efficient selection for a good fraction of the circuits. However, as noted in Section 2.2.2, the ICE model results entirely dominated by medium and large commercial customers, which cost $78 per CMI, and small commercial customers which cost $9.99 per CMI. Residential customers are estimated to cost only $0.06 per CMI. This analysis does not take the variations in segment by segment customer makeup. However, on circuits that serve very few customers, often in highly rural areas, it is more frequent than not only residential customers will be on the circuit, therefore making the argument for undergrounding significantly less tenable. Table 1 shows that for circuit segments without medium or large business the CMI is only $0.68

[69] RAMP; PG&E-2; p. 2.16.

(=$97k/$142k) in PG&E's HFRA. Applying this to Figure 4 would reduce the values in the x axis by a factor of 4.6 (= $3.17/$0.68).

The same distribution for segments planned for PG&E undergrounding in 2024 and 2025 are shown below:

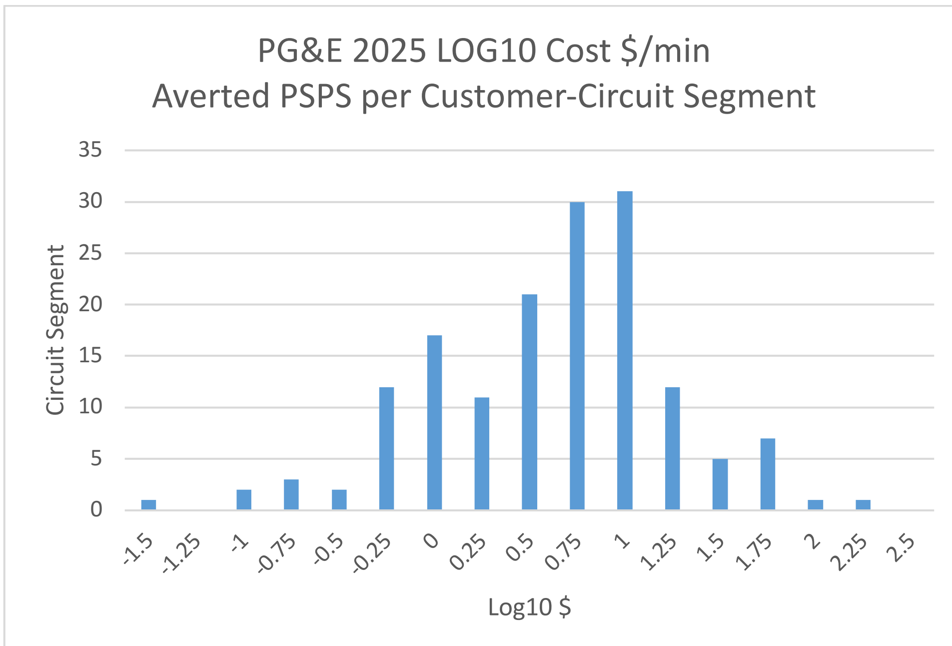

Figure 5 - Cost per avoided PSPS minute for each grid segment in the planned PG&E undergrounding program through 2025.

Note that PG&E's undergrounding program through 2025 will cost roughly 10 times more per customer PSPS minute averted than the undergrounding work that PG&E has already completed.

Comments on the cost of PSPS customer avoidance:

- These are optimistic estimates, since in order for customers to avoid PSPS *all* circuit segments supplying the customer must be treated.
- Some circuits showed zero customers (and therefore infinite cost per PSPS minute avoided. One might optimistically assume that these circuit segments are being treated only for their wildfire risk, subject to check.
- The $60k cutoff is assumed to be the cost of a stand-alone solar installation with storage, but such a solution is not currently practical with existing regulations. However, such high-cost circuit segments should not be prioritized for undergrounding. Instead, covered conductor

with supplemental advanced technology should provide sufficient wildfire ignition protection, and under extreme conditions these circuits should also be subject to PSPS and EPSS as appropriate. Grants for long-term battery storage for customers on these circuits would still cost substantially less than undergrounding the circuit segments.

- PG&E has exhausted the "low hanging fruit" in their undergrounding programs and is reaching a point where returns in terms of reliability are reduced ten-fold below what they were in 2023 per dollar spent.

Recommendations:

- PG&E should provide data and summaries for underground projects completed to date and planned within 2025 timeframe showing per circuit segment: costs, customers served, and cost per PSPS event per customer as part of its upcoming GRC filing.

3.3. EPSS

3.3.1. EPSS thresholds and impacts

Based on historical data, PG&E claims that the effectiveness for its EPSS program is 73% for large, destructive, and catastrophic fires and 47.19% for small and non-reportable fires.[70] This may be understood that EPSS is roughly 50% effective in preventing ignitions from outages. But once an ignition occurs and wildfire established, why would "EPSS" be responsible for additional suppression? This would appear to be due to the range of weather conditions under which EPSS occurs, and most particularly its bounding by PSPS under the most severe fire weather. EPSS occurs in a "middle range" of weather conditions under which fire suppression is more likely by fire services. For even worse fire weather conditions, PSPS is put into place and no utility outages or ignitions occur at all. Therefore the claim of 76% percent effectiveness for EPSS is somewhat of an exaggeration: EPSS prevents 50% of ignitions and the combination of EPSS, PSPS (which limits how bad conditions can be) and wildland firefighting are likely responsible the additional 29% reduction in large, destructive, and catastrophic fires.

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[70] DR Response: RAMP-2024_DR_TURN_005-Q005, Q006.
WP-EO-WLDFR-M020_EPSS; Tab IN2_EPSS_Effectiveness; Column B2:B3

PG&E achieves this level of effectiveness by setting a relatively low threshold for EPSS based on an evaluation of its Utility Fire Potential Index (FPI).[71] PG&E's FPI Model, which had its last major modification in 2021,[72] is based on PG&E's WRF analysis of its 30-year climatology dataset on a 2 km by 2 km grid, combined with a USFS fire occurrence dataset in the PG&E territory. This is a linear regression model that classifies fire weather into five categories R1-R5.[73] FPI figures prominently in the decision to activate EPSS on a circuit or to initiate a PSPS event. In April 2022 PG&E began to calculate circuit-level FPI forecasts for use in EPSS.[74]

While quite effective as a wildfire mitigation, EPSS has been controversial because of its costs in reliability, significantly increasing the amount of that customers spend without power. Among the complaints heard during public hearings on this topic, a common complaint was that power would go out under conditions that would not readily support a wildfire.

As shown in PG&E's Figure 1-2, EPSS consequences make up 21 percent of its total residual risk after mitigation.

[71] PG&E-4; p. 1-9; Figure 1-4; EPSS ENABLEMENT CRITERIA.
[72] OEIS Docket # 2023-2025-WMPs Pacific Gas and Electric Company; 2023-2025 Wildfire Mitigation Plan R62023-2025 R6; July 5, 2024.pp. 104, 932-933.
[73] R.18-10-007; PACIFIC GAS AND ELECTRIC COMPANY; 2021 WILDFIRE MITIGATION PLAN – REVISED; JUNE 3, 2021; p. 74.
[74] DR Response MGRA001-Q002b.

FIGURE 1-2
2027 TY BASELINE (WITH AND WITHOUT OPERATIONAL MITIGATION)

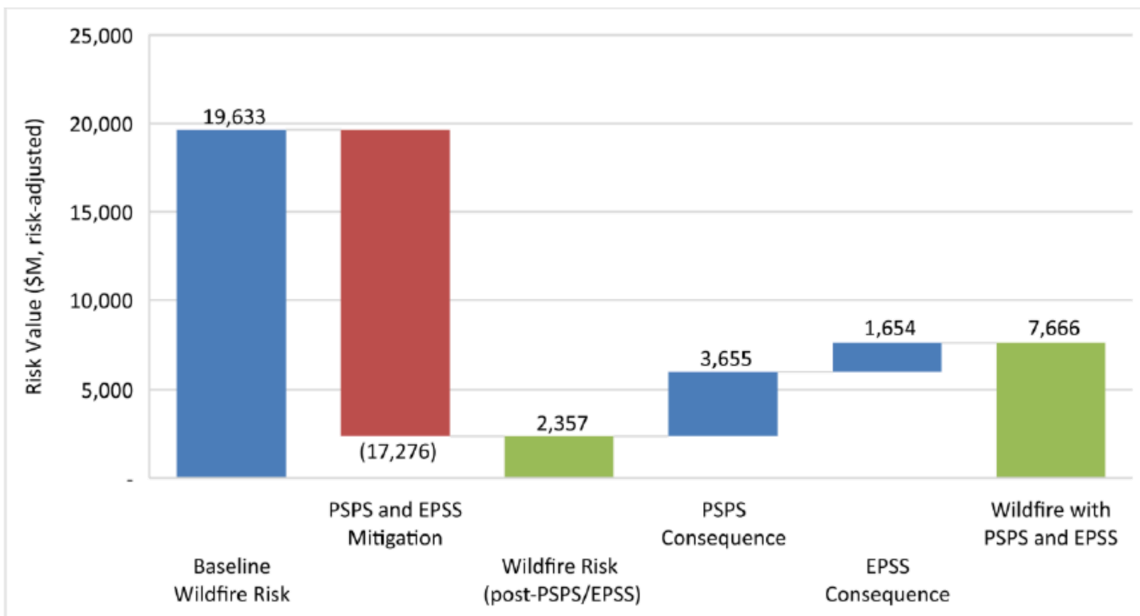

Figure 6 - PG&E Figure 1-2,[75] showing baseline and residual total risk with and without mitigation. PSPS and EPSS can be seen to make up the majority of the residual risk.

According to PG&E, PSPS and EPSS consequence risks correspond mostly to reliability and financial risks, as comparison between PG&E's Figure 1-3 and 1-2 shows that safety risk from PSPS and EPSS total only about 1% of the size of the other consequences of EPSS and PSPS (reliability and financial).

Without arguing the validity of PG&E's estimates, it is important to note that any measures that can be taken to make PSPS or EPSS more "precise", to reduce the number of customers, area affected, or length of outage would have positive effects in reducing reliability and financial consequences.

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[75] RAMP; PG&E-4; p. 1-6.

FIGURE 1-3
2027 TY BASELINE SAFETY VALUES (WITH AND WITHOUT OPERATIONAL MITIGATION)

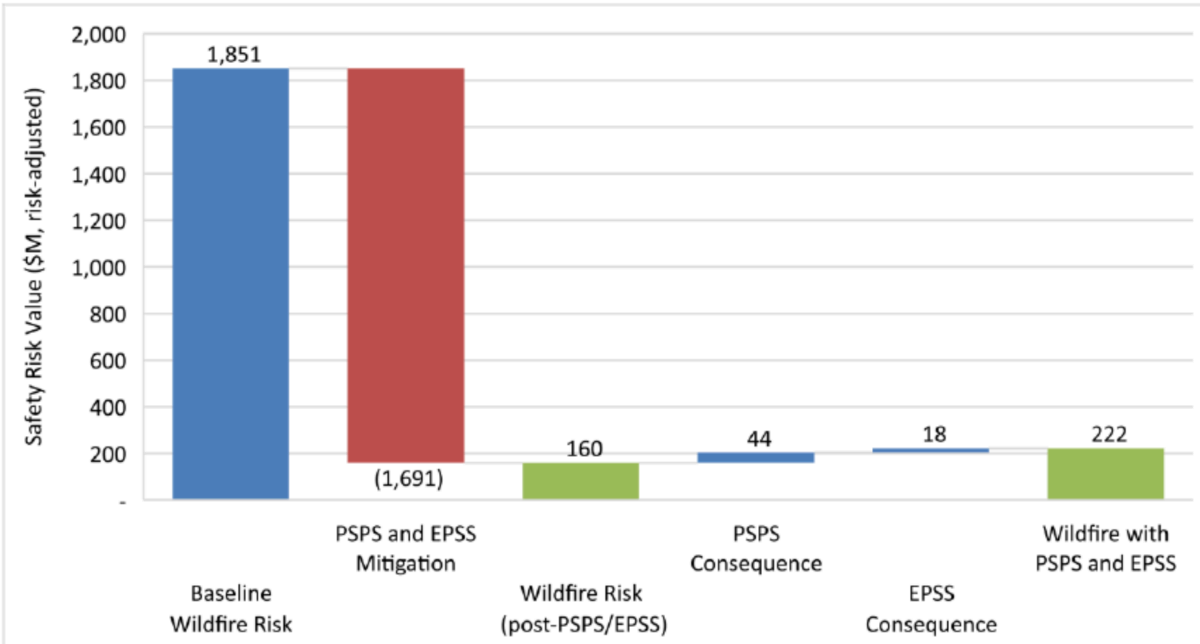

Figure 7 - PG&E Figure 1-3, showing baseline and residual total safety risk with and without mitigation.[76]

Specifically, it should be noted that PG&E's FPI is "coarse-grained", using a 2 km X 2 km grid, and is based upon WRF simulations. Weather may vary on a fine scale, much smaller than 2 km due to fine-grained turbulence, local topography, and obstructions.[77] This can leads to considerable variation between local measurements and predicted values.

As of 2024 Q1, PG&E had also deployed 1,481 weather stations.[78] These are used in PSPS decision making, but PG&E does not use them in conjunction with its predicted FPI values in order to determine EPSS thresholds.

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[76] Id.
[77] Potter, B., Yedinak, K., Charney, J., 2024. Measuring Wind Creating New Models to Gauge Impact on Wildfire. International Association of Wildland Fire - Wildfire Magazine 18–22. https://www.iawfonline.org/article/measuring-wind-creating-new-models-to-gauge-impact-on-wildfire/
[78] OEIS; Energy Safety Data Guidelines Appendix D, Section 1.2; Wildfire Mitigation Data Tables Template: Tables 1 – 15; Table 7; PG&E_2023_Q4_Tables1-15_R2.xlsx

3.3.2. Outage and EPSS Outage Local Weather Analysis

MGRA issued its Data Request 1-1 and 1-2 in order explore the "ground truth" of what the local weather conditions were in the vicinity of an outage when an EPSS event occurred in order to see if an opportunity exists to make EPSS targeting more precise using local data. PG&E responded with datasets describing outage data between 2021 and 2024, which MGRA analyzed. This analysis is fully described in Appendix A of these Informal Comments but a brief description and results are shown below.

The results of analysis performed in the Excel data sheet[79] created by MGRA for merging the two PG&E data sets and processing them is presented below, with calculation details in Appendix A, Section 1.

[79] RAMP-2024_DR_MGRA_001-Q002Supp01Atch01-EPSS-processed-jwm.xlsx.
Available at: https:// hub.com/jwmitchell/Workpapers/tree/main/PGERAMP24

PG&E's process for enabling EPSS settings is described in the figure below:

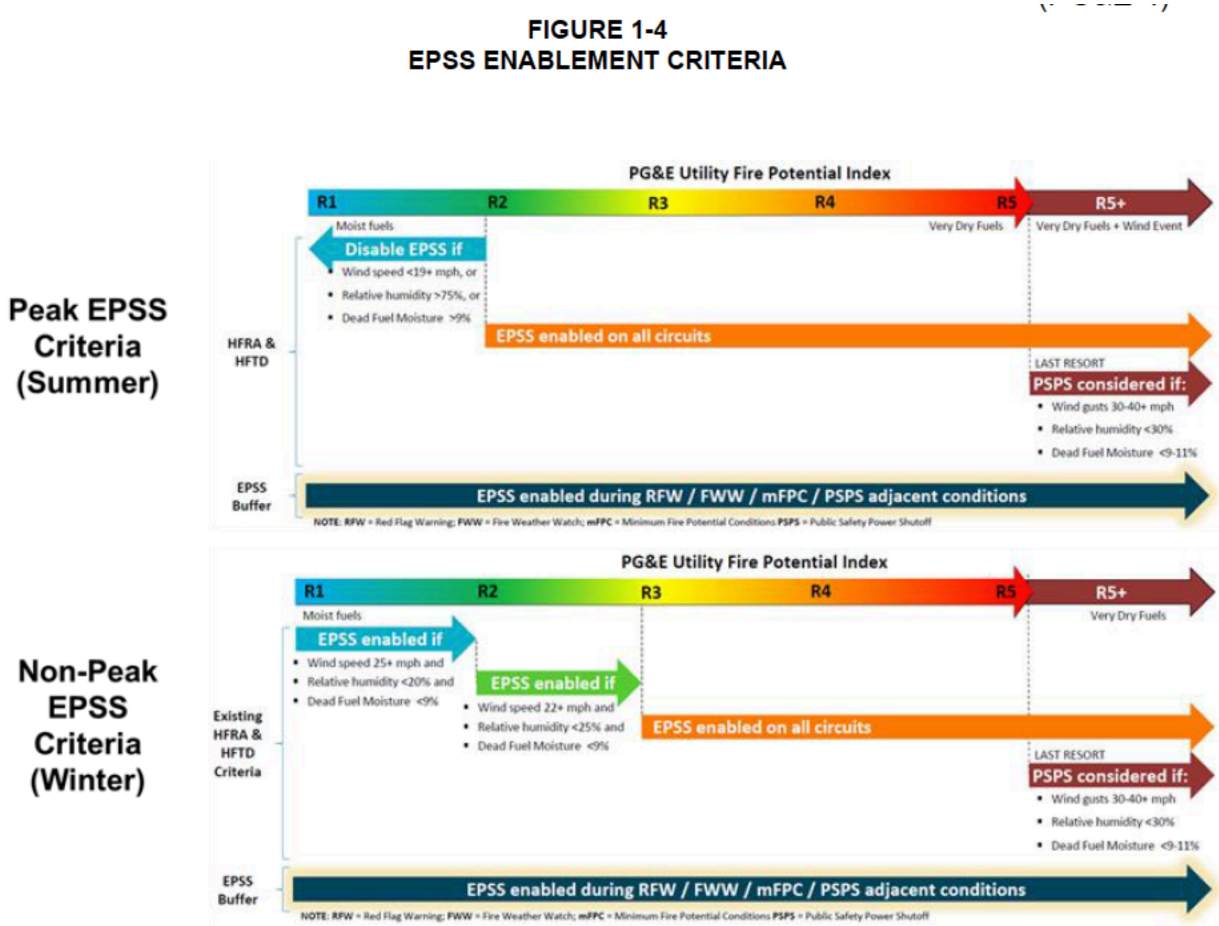

Figure 8 – PG&E-4 figure 1-4 describing PG&E's EPSS enablement criteria. FPI levels of R3 and above enable EPSS during all seasons. Level of R2 is enabled during summer, and during winter during periods of moderate winds, low humidity, and dry fuels. In summer, R1 enables EPSS by default unless wind, relative humidity, or fuel moisture fall below thresholds, whereas in winter EPSS will be enabled for high winds or low humidity.

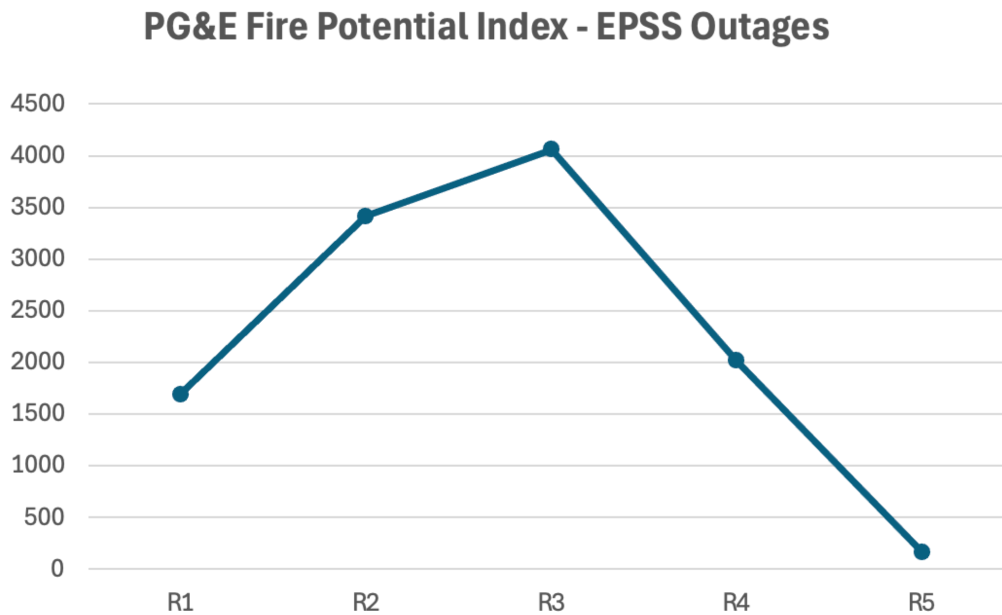

Figure 9 - PG&E outages associated with EPSS settings and the PG&E Fire Potential Index (FPI) associated with those settings. Data is from 1/29/2022 to 12/27/2023.

The figure above shows the distribution of outages occurring with EPSS settings active, binned into the FPI setting for the circuit experiencing the outage. The peak number of outages occur during R3 conditions, and there may be several factors contributing to that. First, R1 and R2 conditions do not always result in EPSS enablement, whereas R3 always do. A second potential contributing factor is that the weather associated with the FPI level may in fact be causing the outage. However, a comparison of "agent" based causes (external drivers unrelated to weather) and "non-agent" based causes (vegetation and equipment failure) reveals no difference in dependence of outage number on either FPI or maximum wind gust.[80]

FPI values were only provided for outages with EPSS enabled. PG&E provided a complete set of outage data with weather station measurements associated with each of the circuit experiencing the outage. Each outage typically was associated with multiple weather stations, so the most extreme values for temperature (highest, ^{o}F), relative humidity (lowest, %), and wind gust speed (highest, mph) were calculated for each outage event. An ad-hoc additive fire weather metric based on these three variables that varies between -2 and 10 was also calculated for each weather station measurement and for the extreme value for the outage by adding the score for temperature, humidity and wind gust speed, as described in Appendix A Section 2.3. When all outages are

[80] Id.; Sheet 'Graphs3'

compared against EPSS outages only, it is apparent that the metric captures the fact that EPSS outages occur under more severe weather conditions than outages generally:

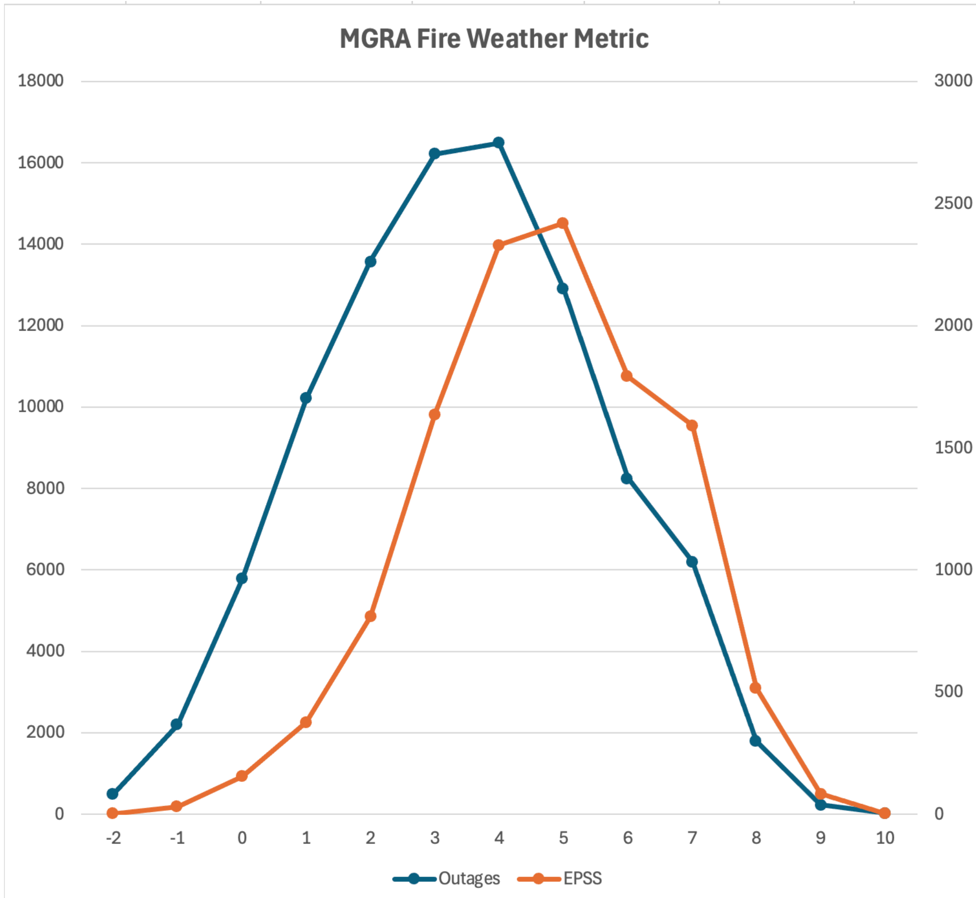

Figure 10 - MGRA's fire weather metric based on temperature, humidity, and wind gust extrema for all outages between 2021 and 2024 and for outages with EPSS settings enabled.

The fire weather metric can also be compared directly against FPI for EPSS events. The graph below shows the fraction of outages classified as each FPI value (R1-R5) for each value of the MGRA fire weather metric.

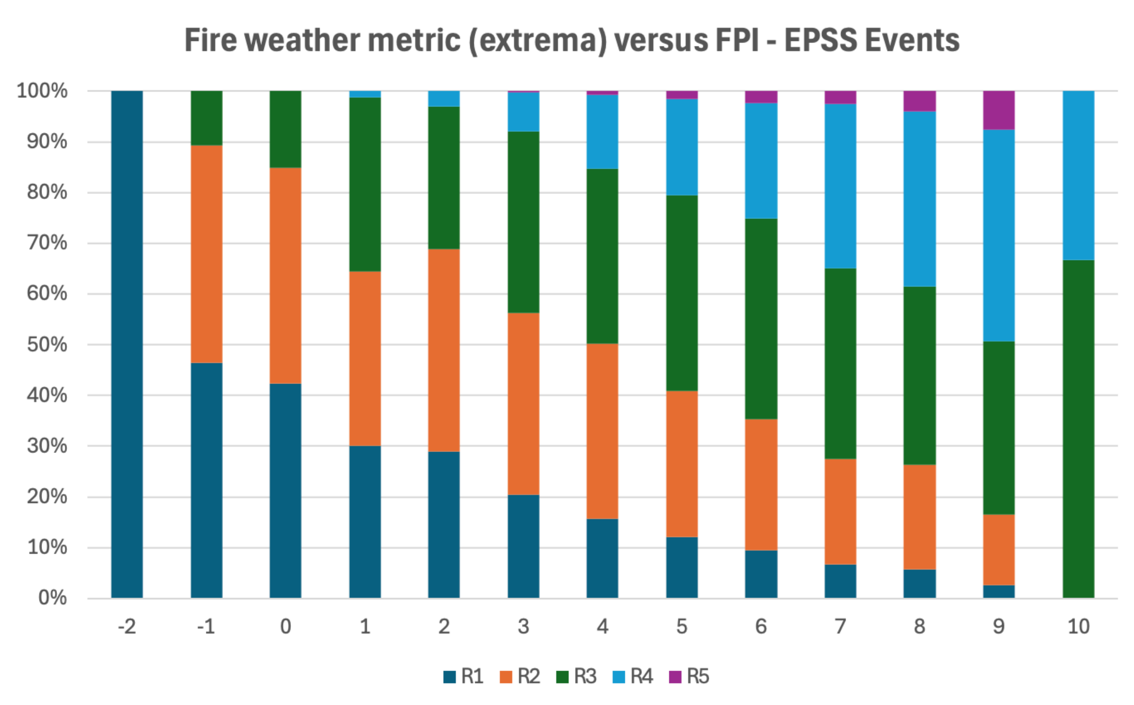

Figure 11 - For each value of MGRA's fire weather metric, the fraction of events classified by FPI ranking is shown.

There is a clear correlation between ad-hoc fire weather metric calculated by MGRA and the FPI ranking, despite the fact that the MGRA weather metric does not take into account fuel moisture, vegetation, or fire history as FPI does. This shows that the local conditions, at least the most severe local conditions, correlate reasonably with PG&E's climatology-based weather model and that other contributions to FPI such as fuel moisture and vegetation do not overwhelm the FPI metric.

To study the other component of the problem – how much weather varies across the landscape in the vicinity of each circuit, the weather metric is calculated for each individual measurement rather than using the most extreme values. The comparison is shown in the graph below:

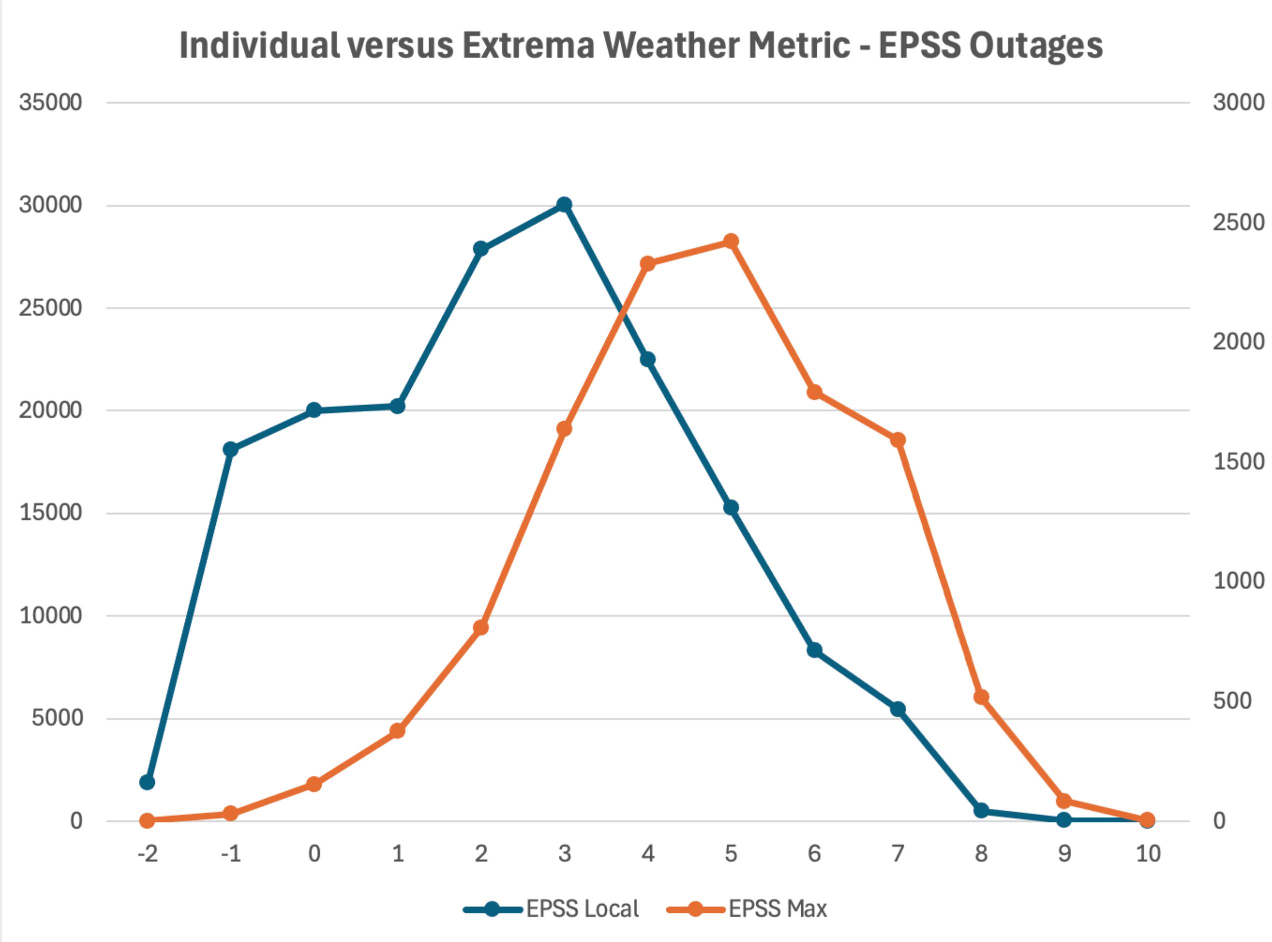

Figure 12 - MGRA fire weather metric for the weather value extrema for each circuit (Max) compared to the weather metric for each individual weather station (Local). This demonstrated the variability in weather measurements in the area adjacent to the circuit.

This graph shows that significant variation of weather conditions occurs across the same circuits, with "typical" weather conditions significantly milder than "worst case" and implying that the worst-case weather conditions may be highly localized.

Local weather conditions can also be compared against FPI for the circuit as shown below:

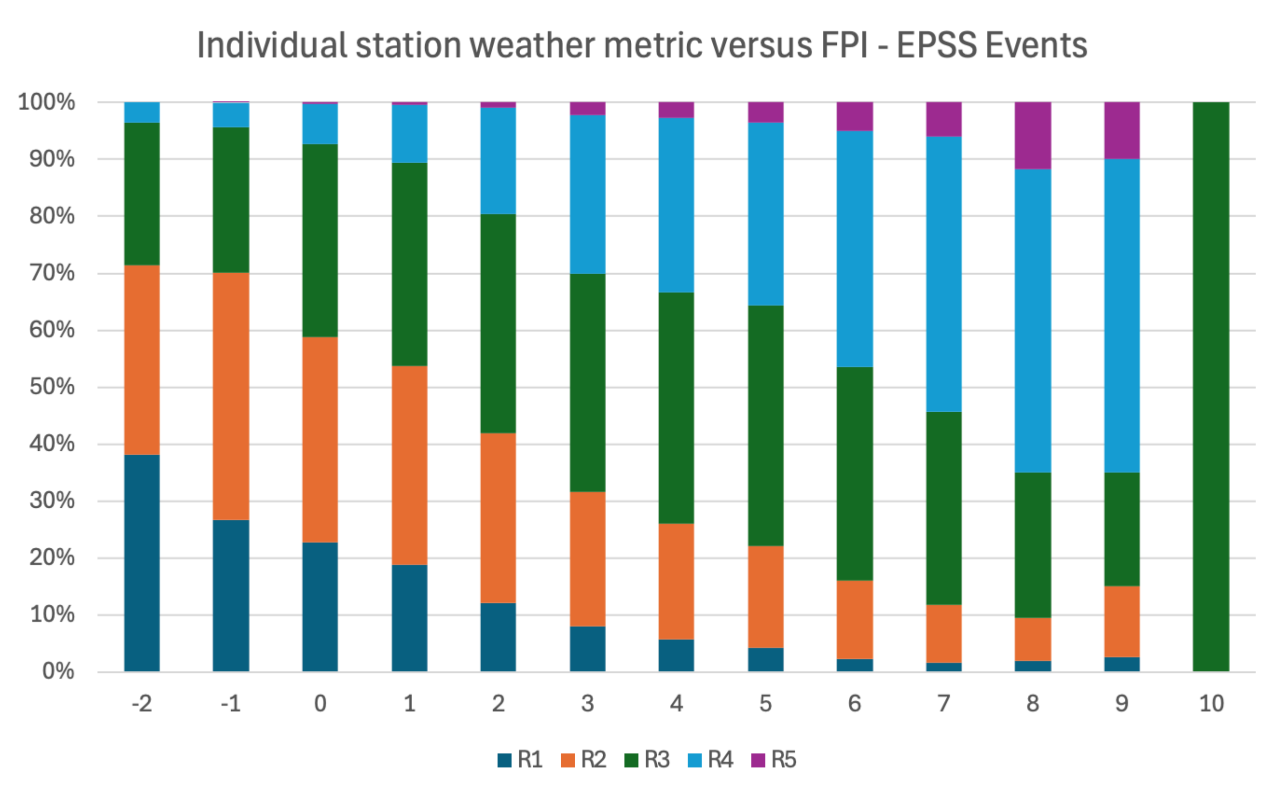

Figure 13 - Weather metric calculated from individual weather station data for all EPSS outages is compared against the FPI value for the circuit associated with the weather station.

In general form, Figure 11 and Figure 13 are very similar: both the extrema weather metrics and the individual station weather metrics show a clear correlation with FPI. The extrema weather metrics show a larger fraction of R1 and R2 FPI levels, but even for individual weather stations over 10% of moderate to severe weather measurements (MGRA metric >5, for instance a RH of 15%, temperature of 85 degrees F, and wind gust of 18 mph would be a 6) that could propagate a wildfire under dry fuel conditions.

3.3.3. EPSS and Covered Conductor

It has been shown by joint studies by the three major utilities that covered conductor provides a substantial decline in fault rates. In the Joint Report authored by SCE, PG&E and SDG&E, an SCE diagram shows this very distinctly:

Figure 8: SCE Faults on HFRA Circuits in 2021

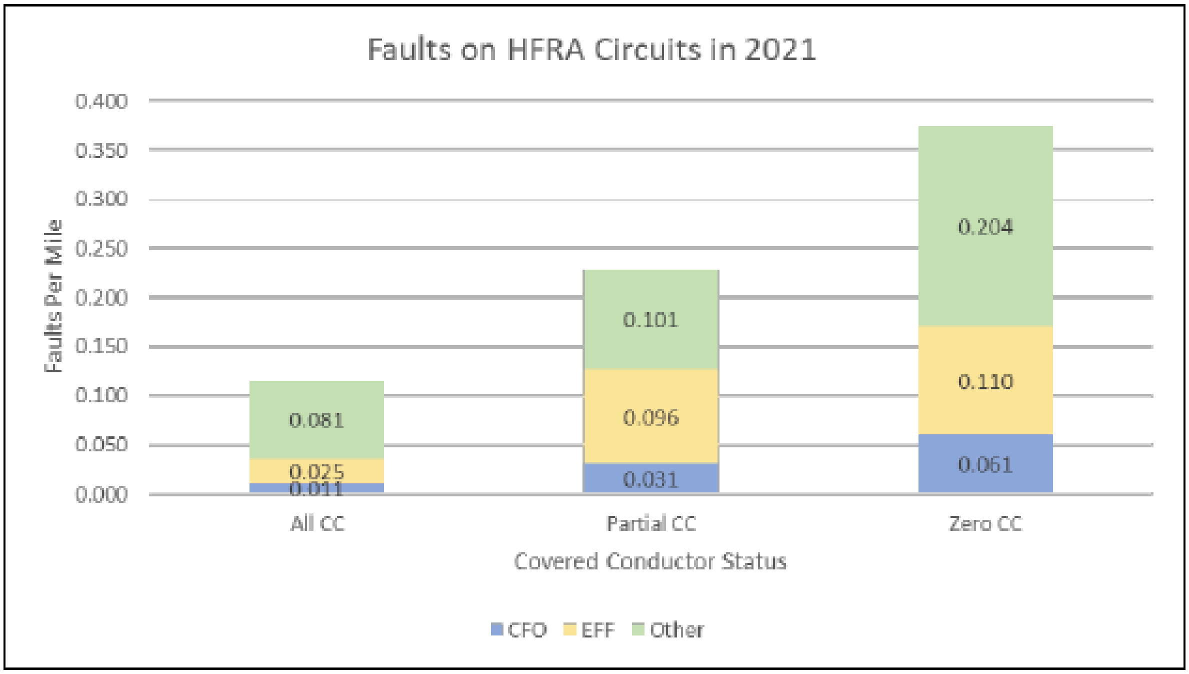

Figure 14- SCE faults on HFRA circuits for circuits with, without, and partially with covered conductor. CFO is "contact from object" and EFF is "electrical facility failure".[81]

Covered conductor significantly reduces the rates of fault. It follows that EPSS outages should likewise be reduced in areas where covered conductor is deployed. PG&E should ensure that when calculating cost/benefit efficiencies for covered conductor these reductions in EPSS outages are taken into account. PG&E currently does not collect any metrics that correlate EPSS and covered conductor.[82] It should be required to do so.

3.3.4. EPSS Conclusions

EPSS trigger conditions correlate with but do not exactly track individual station and circuit extrema weather data. As shown in Figure 13, a significant tail of moderate to severe weather conditions (over 10%) are classified as R1 or R2, probably because PG&E uses WRF wind speed predictions to make the determination of whether R1 and R2 will cause EPSS to be enabled.[83]

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[81] OEIS; TN10587-1_20220211T151544_20220211_SDGE_2022_WMPUpdate_R0; SDG&E 2020-2022 Wildfire Mitigation Plan Update; Attachment H; Joint IOU Response to Action Statement-Covered Conductor; p. 25.
[82] DR Response RAMP-2024_DR_MGRA_001-Q003.
[83] DR Response RAMP-2024_DR_MGRA_002-Q001.

Looking at the extrema, (Figure 11), one also sees that in half of the cases where the extrema weather values are mild to moderate (MGRA metric < 5, for instance an RH of 60%, temperature of 70 degrees F, and wind gust of 25 mph would be a 4) the FPI is ranked R3, R4 or even R5. This suggests that EPSS settings determinations of at least R3 and potentially R4 should also be informed by either WRF wind speed predictions or local conditions that use weather station data and dry fuel moisture. The peak FPI for EPSS outages occurs at R3 (Figure 9), so a reduction of false positives in the R3 bin cause a measurable reduction in EPSS outages under conditions that are less than likely to initiate a significant wildfire.

It may be possible for the combined data set – live local weather station data and fuel moisture plus predicted FPI, to be optimized using a data model to provide an optimal trigger point for enabling EPSS settings, thus reducing false triggers and minimizing the risk of significant fire. Currently, PG&E's EPSS settings are updated once per day, due to limitations in throughput of their control infrastructure, although this could be made more frequent with additional automation.[84] As more frequent updates with live information may reduce EPSS risk, PG&E should submit a proposal to fund further EPSS automation in its GRC.

Recommendations:

- Either WRF wind speed predictions or real-time weather conditions and fuel moisture should be taken into account for FPI=R3 in the same manner that they are for R1 and R2 to ensure that EPSS is not being enabled under conditions not likely to support significant wildfire growth.
- PG&E should study the feasibility of a data model incorporating FPI and live weather and fuel data to come up with an optimized threshold for EPSS settings.
- Because EPSS is "bracketed" on the severe side (FPI=5+) by PSPS, the number of ignitions of unreportable and small fires should not be over-relied on as the metric to measure EPSS success. EPSS has significant impact on reliability and therefore cost/benefit. A cost/benefit study of EPSS thresholds should be performed that balances losses due to small and unreported wildfires against reliability impacts. Any modifications to EPSS thresholds should be incorporated into overall cost/benefit ratios for alternative mitigations.

[84] DR Response RAMP-2024_DR_MGRA_003-Q003.

- PG&E should collect data on its covered conductor deployments that allows it to determine its own value for the effectiveness of covered conductor in preventing EPSS outages.
- PG&E should submit a proposal to improve its EPSS automation in its upcoming GRC.

3.4. PSPS

As shown in PG&E's Figure 1-2,[85] the risk reduction efficiency of PSPS and EPSS together is very high, nearly 90%. PG&E acknowledges that "*PSPS and EPSS are the most Wildfire Risk reducing and cost-effective programs PG&E deploys*."[86] However, there are a number of factors that are driving PG&E to reduce its dependency on EPSS and PSPS and move to hardening solutions, which PG&E considers to be primarily undergrounding:

- Legislation such as SB 844, which direct OEIS and the Commission to use hardening (specifically undergrounding where cost-effective) to improve reliability.
- The OEIS mandate is to eliminate wildfire risk and outages used to prevent wildfires.
- The Commission has directed utilities repeatedly to use PSPS only as a "last resort".
- Adoption of the ICE model has greatly increased the consequences of PSPS.
- From a financial standpoint, PG&E is incentivized to reduce risk through investment of capital infrastructure, while maintaining the ability to efficiently execute PSPS is a cost.

3.4.1. PSPS and Covered Conductor

As MGRA has presented in these comments and elsewhere, there is strong evidence that PG&E has significantly understated the benefits of covered conductor overhead hardening, particularly in conjunction with technological mitigations such as downed conductor detection (DCD) and electronic fault detection as wildfire mitigation. Additionally, the significantly lower cost of covered conductor gives it a substantial advantage over undergrounding in terms of cost/benefit ratio in most cases. However, the argument in favor covered conductor is not as strong for reliability risk, since a typical failure mode during high wind events is for a large tree to fall into

[85] RAMP; PG&E-4; p. 1-6.
[86] RAMP; PG&E-4; p. 1-4.

a power line. PG&E's DCD solution mitigates this problem to a large extent, as shown in the table below from their 2025 WMP Update.

TABLE ACI-PG&E-23-05-3:
IGNITION MITIGATION EFFECTIVENESS: REPRESENTATIVE BLENDED AVERAGE VALUES

Scenario	Blended Average Effectiveness[a]
Alt. 1 – Baseline	0%
Alt. 2 – Underground Primary	97.7%
Alt. 3 – Underground All	99.2%
Alt. 4 – Covered conductor (CC) Overhead with EPSS	78.2%
Alt. 5 – Bare Conductor Rebuild with EPSS and downed conductor detection	60.9%
Alt. 6 – Line Removal w/ Remote Grid	97.7%
Alt. 7 – EPSS including downed conductor detection (DCD)/Partial Voltage (with bare conductor)	60.4%
Alt. 8 – EPSS and PSPS (with bare conductor)	91.3%
Alt. 9 – Rapid Earth Fault Current Limiter (REFCL), CC Overhead, EPSS and DCD	65.0%
Covered Conductor Rebuild – New	66.4%(b)

Assumptions:

- Analysis assumes no Overhead degradation for life of the asset;
- EPSS and DCD are only active when conditions are greater than R1;
- Ground sensitivity on 4 wire systems for high impedance faults similar to DCD mitigation; and
- Mitigation effectiveness for other Environmental caused outages: None for Overhead and All for Underground.

(a) These are averages based on review of 8 years of outage history between 2015 and 2022. This historical review differs from the methodology used to calculate the annual effectiveness reported by PG&E for any given year.

All of these effectiveness values represent a blended average effectiveness at the circuit segment level with the exception of "Alt. 9 – REFCL, CC Overhead, EPSS and DCD" which is a substation effectiveness score. Not all substations are capable of having REFCL applied, and it cannot be isolated to a circuit segment only.

The approach to calculating outage risk considered the following outage types, however they were deemed not applicable and therefore excluded:

No improvement for existing Underground Type outages; and

All company-initiated outages, Community Wildfire Safety Program and PSPS outages fire forest/grass outages – potential wildfire cause outage/force out.

(b) The mitigation effectiveness value for CC used in the WBCA (66.4%) is similar to the value arrived at as part of the joint California IOUs CC effectiveness study for 2022 (64%). See PG&E's 2023-2025 WMP, Revision 1, April 26, 2023, page 900.

Table 12 - PG&E's ignition mitigation effectiveness table for alternative mitigations.[87]

PG&E's risk reduction effectiveness for covered conductor is listed at 66.4%, while EPSS including DCD is listed with an effectiveness of 60.4%. Combined, these would have an effectiveness of 86.7%. If MGRA's estimate of covered conductor effectiveness based on SCE field data is used instead (85%), the risk reduction using EPSS/DCD would be 94%. This is very good, but is an average over all ignition drivers. As wind speeds increase, faults from equipment damage and vegetation contact increase as a high polynomial or exponential dependency, so the potential for

[87] PG&E 2025 WMP Update; p. 55.

ignition under catastrophic conditions likewise increases. Worst-case scenarios, such as 100 year wind events with many fall-in trees would still present a substantial risk. PSPS, therefore, cannot be avoided for above-ground equipment, but the frequency, duration, and extent can be substantially reduced by raising the threshold.

3.4.2. PSPS and Thresholds

The effect of a raised PSPS threshold can be studied using wind data from utility and other mesonets. PG&E's weather station network has grown to more than 1,500 weather stations, each placed to represent weather conditions proximate to its infrastructure. It began installing stations in 2018, and continues to deploy new ones. These stations provide wind speed measurements every 10 minutes.[88]

In MGRA Data Request 1, Question 5, MGRA requested that PG&E do a wind exceedance study over all PG&E weather station history, measuring the number of measurements that exceed four thresholds: 58 mph, 65 mph, 70 mph, and 84 mph. PG&E responded with the file RAMP-2024_DR_MGRA_001-Q005Atch01.xlsm, which was analyzed and posted as an MGRA workpaper as RAMP-2024_DR_MGRA_001-Q005Atch01-Wind-jwm.xlsm. Result of the analysis summarized over all of PG&E's weather stations is presented in the table below:

[88] DR Response RAMP-2024_DR_MGRA_001-Q005.

Number of Stations	Gust Threshold (mph)	Annual Count
	58	199
	65	101
	70	59
	84	14
Measurements above threshold		**Total Count above threshold**
	58	20382
	65	6972
	70	3021
	84	409

Table 13 - Effect of wind gust threshold on number of PG&E weather stations exceeding threshold more than once yearly and total number of measurements over threshold.[89]

Analysis resulting in Table 13 is described in Footnote 89. The "Count" data represents the number of stations exceeding threshold annually, and is a proxy for the geographical "extent" of the PSPS events. It is interesting to note that only 199 stations out of PG&E's >1,500 annually exceed a 58 mph wind gust, implying that high wind risk is a localized problem. Raising the threshold to 65 mph would drop the number of stations to 100, reducing the number of stations (and by proxy area) affected by half. Only half again of these stations experience wind gusts of over 70 mph annually, implying that annual PSPS would only be necessary on a small fraction of circuits. Circuits regularly experiencing conditions of excessive wind are good candidates for undergrounding and should be given priority.

The total count above threshold measures the number of 10 minute measurements observed across the PG&E service area in HFTD Threat Districts 2 and 3 above threshold for all stations over

[89] Workpaper RAMP-2024_DR_MGRA_001-Q005Atch01-Wind-jwm.xlsm.
Description of analysis:
PG&E's raw data was modified by adding a calculated start year column (Tab MGRADR1_Q005). Data was selectively copied to the Gust Rates Tab using several criteria: 1) wind gust data only (this is more accurate than "average" wind speed for PG&E weather station design) 2) data starting in 2019 and ending in 2023 (2018 and 2024 data sets do not represent an entire year). Columns were added to sum the number of exceedances over all years, and also to calculate the mean number of gust exceedances annually. If the number of annual exceedances was 1.0 or greater, a "CountYr" column was set to 1. A number of weather stations reported only 1 exceedance event in their history, and this event exceeded 84 mph. This was flagged as an error condition and these stations were not used in the summary. A pivot table was constructed on Tab "Tables" and the summaries presented in Table 13 were performed.

the entire history. This proxy is influenced by the frequency, extent, and duration of extreme weather conditions. It shows a somewhat steeper drop off with rising threshold than does the count proxy, showing a 3X reduction between 58 and 65 mph and a 8X reduction between 70 and 84 mph. The 6,000 exceedance measurements (representing 1,000 station-hours) over 58 mph is small considering that PG&E claims to have analyzed 300 million weather station measurements (50 million station-hours) in order to produce its data set.[90] This indicates that conditions meriting PSPS constitute a small fraction of the overall PG&E service area over geography and time.

Recommendations:

- When modeling PSPS consequences using backcasting for covered conductor alternative mitigations in its GRC, PG&E should include the effect of an increased PSPS wind speed threshold (65 mph for example).
- PG&E should present data with its GRC using its analysis of post-PSPS patrol damage and risk reports to determine the residual risk for covered conductor if wind speed thresholds were to be incrementally raised to 65 mph.

4. CONCLUSION

The MGRA analysis presented in these comments deeply explores some of the key areas in which PG&E's risk profile and methods have dramatically changed since its previous RAMP filing. Hopefully, SPD can make use of these observation as it prepares its own recommendations.

Many of the analysis results are based on extensive calculations, usually derived from PG&E data request responses. Many data request responses, as data request responses themselves note, took considerable time and effort on the part of PG&E staff, who performed analyses even when disagreeing with the premise or when a difficult computation might have been performed as part of the MGRA analysis itself. This effort is acknowledged, and the current analysis honors this effort with significant additional processing and conclusions. It was a correct decision by PG&E to make these efforts. The MGRA analysis demonstrates the utility of the data and analysis, which is available for future PG&E use.

[90] Op. Cite.

As a whole, the MGRA analysis presents a dramatically different vision than that proposed by PG&E. PG&E's model for the future is "undergrounding world" where wildfire risk and reliability risk are slowly and methodically eliminated wherever they exist over the next decades, at very great expense to the ratepayers. The results presented in the MGRA analysis, in contrast, allow a different vision to emerge: a world where wildfire safety and reliability risks are eliminated at a much greater pace and at significantly lower cost, where undergrounding has its proper place as a tool but is not a "cornerstone" of the risk reduction.

The battle over these visions will not occur in the RAMP, but rather in the GRC and in PG&E's upcoming SB 884 undergrounding application. The RAMP outputs therefore – MGRA's recommendations – are designed to inform the upcoming applications. We would ask SPD and other intervenors to incorporate or support these recommendations in this proceeding.

Submitted this 9th day of October, 2021,

By: __/S/____***Joseph W. Mitchell***____________________

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APPENDIX A – MGRA WEATHER ANALYSIS DETAILS

1. ORIGINAL PG&E DATA

PG&E provided Excel spreadsheets in response to MGRA data requests MGRA_001-Q001 and MGRA_001_Q002. These were:

1.1. RAMP-2024_DR_MGRA_001-Q001Atch01.xlsx

This file consists of data representing 307,357 outages that occurred on EPSS-enabled circuits between 1/1/2021 and 7/31/2024.

This file provides the following fields which were used in the MGRA analysis:

- Feeder Name
- Date Outage
- Time of Outage
- Circuit EPSS Enabled
- Basic Cause
- Supplemental Cause
- Outage #

1.2. RAMP-2024_DR_MGRA_001-Q002Supp01Atch01.xlsx

This file is comprised of 94,366 outage records recorded between 1/1/2021 and 1/9/2024. PG&E did not apply circuit-level FPI forecasts for EPSS until 2022, and the earliest date in their archive containing that data is late April 2022.[91] PG&E was asked to provide temperature, humidity, and wind gust speed from the nearest stations to the point of the outage. PG&E collected multiple weather entries per outage from multiple weather netwoks including [92], and collected 1,003412 data points.

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[91] PG&E DR Response MGRA_001-Q002.
[92] ???

PG&E notes that "*weather stations from multiple weather station networks are mapped to each circuit. For this request PG&E provided the weather conditions reported at any station from the multiple networks (PG&E, ASOS, RAWS, etc) associated to the circuit experiencing the outage. As such, multiple readings may be included for each outage, which represent the different readings for each weather station mapped to the circuit*."[93]

This file provides the following fields that were used in the MGRA analysis:

- Feeder Name
- Date Outage
- Time of Outage
- Temperature (F)
- Relative Humidity
- Max Wind gust (mph)
- Utility Fire Potential Index (circuit based)

1.3. Initial analysis and screening.

Files were all sorted in time order, using start date as primary sort and time of outage as secondary sort. Unfortunately a unique outage ID was not provided in the latter file, so the analysis created its own unique outage identifier. This identifier was comprised of three fields:

"DateOfOutage-TimeOfOutage-FeederName"

This field was then used to cross-reference between the differrent PG&E spreadsheets.

For Basic Cause, a filter was replied removing outages meeting the following categories.

- Company Initiated
- Wildfire Mitgation

[93] DR Response RAMP-2024_DR_MGRA_001-Q002Supp01.

1.4. Merging

In order to place all data being analyzed into one file to reduce the chance of reference errors and for easier access, sheets were copied from the original P&GE Excel spreadsheets into a "master" analysis workbook:

RAMP-2024_DR_MGRA_001-Q002Supp01Atch01-EPSS-processed-jwm

Data obtained by reference was sometimes replicated into separate columns or sheets by Value in order to speed computation time and lessen the chances of future reference errors.

2. ANALYSIS AND PROCESSING OF PG&E WIND AND OUTAGE DATA (SHEET MGRA WEATHER OUTPUT Q2)

2.1. Determination of "worst case" weather conditions near outage

Each row in this sheet consisted of an individual weather station measurement at the time of outage, along with circuit information.

For set of weather data grouped by outage the following additional fields were calculated:

- Maximum Temperature (F) measured in the circuit area
- Minimum Relative Humidity measured in the circuit area
- Maximum Wind Gust (mph) measured in the circuit area

It should be noted that these three extreme values do not necessarily occur at the same weather station, but instead are intended to show the "worst case" weather values that had been experienced by the circuit at the time of the outage.

2.2. Assignment of weather records to outages

The row of each outage is calculated and recorded in Row N (first_outage_row).

2.3. MGRA Local Weather Risk Score

To what degree to weather variables determine the likelihood that a wildfire will ignite from an electrical spark and to what degree a wildfire ignited by utility equipment will spread and become a danger is a problem that has been addressed in abundant literature, and which PG&E has taken into account with its Fire Potential Index (FPI). PG&E's FPI Model, which had its last major modification in 2021,[94] is based on WRF analysis PG&E's 30-year climatology dataset on a 2 km by 2 km grid, combined with a USFS fire occurrence dataset in the PG&E territory. This is a linear regression model that classifies fire weather into five categories R1-R5.[95] FPI figures prominently in the decision to activate EPSS on a circuit or to initiate a PSPS event.

In order to come up with a local metric that can be used to compare FPS data against local weather data, an additive metric was constructed from weather station values according to the following mapping (Sheet WFRiskLookup):

Temp(F) max	45	60	78	90	130
Temp(F) min	0	45	60	78	90
Score	-1	0	1	2	3
RH max	0	25	50	70	90
RH min	25	50	70	90	100
Score	3	2	1	0	-1
Wind gust mph max	10	20	30	40	120
Wind gust mph min	0	10	20	30	40
Score	0	1	2	3	4

Table 14 - MGRA additive fire weather severity metric based on temperature, humidity, and relative humidity readings from weather stations.

[94] OEIS Docket # 2023-2025-WMPs Pacific Gas and Electric Company; 2023-2025 Wildfire Mitigation Plan R62023-2025 R6; July 5, 2024.pp. 104, 932-933.
[95] R.18-10-007; PACIFIC GAS AND ELECTRIC COMPANY; 2021 WILDFIRE MITIGATION PLAN – REVISED; JUNE 3, 2021; p. 74.

The three score values are added together for each measurement to give a value ranging from -2 to 10. For example, a measurement of 70 degrees F, relative humidity of 30, and wind gust speed of 15 mph would have a score of 4. This is of course a limited metric because it does not contain key features that FPI does such as vegetation type or dry fuel moisture, and it has not been calibrated against actual fires. However it does has use as a comparison to determine 1) how well the FPI metric is able to predict local ground conditions and 2) the variation of wildfire-related weather components occurs across the landscape.

2.4. Tab MGRAWeatherOutputMax

This is a simplified version of the "MGRA weather output Q2" sheet, in which only the outages are copied over along with their maximum temperatures, minimum humidity, and max wind gust recorded on any weather station during the outage. This was done to provide a stable copy of the outage data without unstable references.

2.5. Tab MGRAOutageMax

This sheet merges the two data sets from Data Request 1 Questions 1 and 2, using the created "ID" field as the key. For each outage it keeps only the maximum temperature and wind gust values and minimum humidity recorded at any nearby weather station at the time of the outage. Cause information is also included.

2.6. Graphs Tab

This sheet contains a pivot table that is constructed from the data on Sheet MGRAOutageMax. The data from this pivot table was used to construct a number of graphs and tables in Section 3.3. Specifically these tables and graphs refer to outages only, rather than individual weather station readings. FPI values are plotted as well, but only for outages with EPSS settings, since these are the only outages associated with FPI readings.

2.7. EPSSWeatherMetrics Sheet / Graphs 2 Tab

This is a simplified version of MGRA weather output Q2 Sheet, copied by value and containing only the information necessary to provide all weather station data for each outage as well as the FPI for each outage. This data is used in the Graphs 2 Sheet to create a pivot table containing all weather station records, as opposed to all outage records in Graph 1. This data is intended to provide information regarding local variation of weather in the area of the outage and how it may vary from the “max/min” weather values or the FPI.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39M) to Submit Its 2024 Risk Assessment and Mitigation Phase Report.	Application 24-05-008

INFORMAL COMMENTS OF SMALL BUSINESS UTILITY ADVOCATES

On May 15, 2024, Pacific Gas and Electric Company (PG&E) filed its Risk Assessment and Mitigation Phase (RAMP) report and associated Application (Application) requesting that the Commission both direct the Safety Policy Division (SPD) to review and report upon the contents and close this proceeding subsequent to PG&E's incorporation of SPD's evaluation into its 2027 test year general rate case (GRC) proceeding. As part of the established RAMP process, the Commission is seeking informal comments from stakeholders to gather diverse perspectives and insights on PG&E's risk assessment and proposed mitigation strategies. These informal comments are intended to inform the SPD's review and help ensure that a wide range of concerns and input from stakeholders are considered before the RAMP findings are incorporated into the upcoming GRC.

Given the significant impact that PG&E's risk assessment and mitigation strategies have on small businesses and other ratepayers, SBUA has carefully reviewed the RAMP filing and identified several key areas of concern that warrant particular attention. We also acknowledge that PG&E has made strides in improving its risk assessment methodology since the 2020 RAMP, particularly in its more granular approach to tranching. However, significant concerns and room for improvement remain.

In the Scoping Memo and Ruling, several issues were identified that SBUA, on behalf of small business customers in PG&E's territory, has an interest in. We respectfully ask Safety Policy Division staff to include these issues in their analysis and evaluation of PG&E's RAMP. These issues are the following:

- **Completeness and Compliance of PG&E's RAMP Filing**: As part of ensuring PG&E's RAMP filing is complete and in compliance with RAMP related and governing decisions, SBUA requests that the SPD include assessing whether PG&E's risk quantification methodology, tranche definitions, and Risk Scaling Function adequately capture small business interests and vulnerabilities.
- **Adequacy of PG&E's RAMP Model and Risk Analysis for Mitigation Projects**: How PG&E selects and implements specific mitigation projects and programs has a direct impact on the small businesses in PG&E's territory, so a determination of whether PG&E has adequately used its RAMP model and risk analysis model is key for establishing effective mitigation projects and just and reasonable rates. SBUA requests that the SPD address how these specific mitigation projects impact small commercial customers.
- **Modeling for PSPS and EPSS**: SBUA urges careful scrutiny of PG&E's modeling of risks and mitigations for Public Safety Power Shutoffs (PSPS) and Enhanced Powerline Safety Settings (EPSS), as these dramatically impact small business customers. As SBUA has stated, these customers have a high interest in infrastructure integrity, customer and public safety and energy resilience. Without adequate modeling of the risks and mitigations for PSPS, the issue of having adequate electric power stability will not be addressed.. For example, a small restaurant business needs to refrigerate its food, have lights on for serving customers, and requires power for water supply. . Not only can PSPS directly impact a small business's ability to operate, but if the risks associated with PSPS

are not adequately modeled and addressed, this may result in negative impacts on the rates small business customers pay. PG&E's approach to this modeling, detailed in Exhibit (PG&E-4), should be evaluated for its consideration of small business operational needs and potential rate impacts. Furthermore, SBUA emphasizes the need for thorough assessment of wildfire mitigation risk reduction effectiveness, reliability improvements, and associated costs. As outlined in PG&E's Wildfire risk analysis (Exhibit PG&E-4), these factors significantly affect small businesses' ability to operate safely and pay reasonable rates. Effective measures for infrastructure integrity and public safety from wildfire mitigation risk and reduction and their cost impact are crucial for the ability of a small business to operate as well as to pay only just and reasonable rates. The Commission should examine whether PG&E's proposed mitigations, including their Cost-Benefit Ratios, adequately balance risk reduction with cost-effectiveness for small business ratepayers. SBUA recommends that the SPD pay particular attention to and specifically address how PG&E's PSPS and wildfire mitigation strategies account for the unique vulnerabilities of small businesses, including their limited capacity to absorb extended outages or increased rates.

- **Implementation of the Environmental and Social Justice Initiatives**: Whether PG&E has reasonably implemented the Environmental and Social Justice Pilot study and other related directives ordered in D.22-12-027, and whether the Application aligns with or impacts the achievement of any of the nine goals of the Commission's Environmental and Social Justice (ESJ) Action Plan, are of high importance to small business customers. PG&E's ESJ Pilot Study Plan implementation should be thoroughly evaluated for its impact on small businesses, particularly those in ESJ communities. SBUA urges the SPD to assess not only how PG&E's Application aligns with the nine goals of the ESJ Action Plan but also how it impacts small businesses in those ESJ communities. Of particular interest are Action Items #1 and #6, which address equity in risk evaluation and the impact of risk mitigation investments on disadvantaged and vulnerable communities. SBUA recommends examining whether PG&E's approach adequately considers the unique challenges faced by small businesses in these communities, including potential rate impacts and service reliability issues.

In conclusion, SBUA urges the Commission to carefully consider the unique needs and vulnerabilities of small businesses as it evaluates PG&E's RAMP application. SBUA looks forward to reviewing and commenting on the Safety and Policy Division report after it is filed.

Informal Comments of The Utility Reform Network (TURN)

on PG&E's RAMP Report

A.24-05-008

October 9, 2024

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Informal Comments of The Utility Reform Network (TURN) on PG&E's RAMP Report

TURN appreciates the opportunity to present these informal comments on PG&E's RAMP Report. The comments first discuss issues that are generally applicable to PG&E's risk modeling. TURN then addresses issues specific to PG&E's modeling in relation to the Wildfire risk. A recurring theme in these comments is concern regarding PG&E's implementation of the Cost Benefit Approach (CBA) ordered in D.22-12-027. While these comments speak to many problems that TURN has identified, TURN did not have the time and resources to comprehensively review all aspects of PG&E's risk modeling. Accordingly, TURN's silence on any aspect of PG&E's RAMP submission should not be viewed as TURN agreement with PG&E's methodology or conclusions.

A summary of TURN's recommendations appears in the Appendix to these comments.

1. PG&E's One-Size-Fits-All Electric Reliability Calculation Ignores Geographical Variability in Interruption Cost Estimation

The Lawrence Berkeley National Laboratory (LBNL) Interruption Cost Estimate (ICE) Calculator is a tool designed to estimate the economic costs of electric service interruptions across different customer categories (residential, commercial, industrial).[1] The model considers various explanatory or independent variables such as duration of the outage, time of day, specific industry impacts, among others to predict cost per (outage) event.[2]

The ICE Calculator is primarily equipped to handle outages lasting 24 hours or less, making it less effective for modeling the economic impacts of longer or consecutive outages. The underlying data for the model is partly outdated, relying on surveys that are over 15 years old, which may not accurately reflect current economic conditions and customer behaviors. The Commission's decision acknowledged these limitations and directed IOUs to use the most current version of the ICE Calculator for standard dollar valuation of electric reliability risks or justify the use of an alternative model.[3] [4]

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[1] https://emp.lbl.gov/projects/economic-value-reliability-consumers#:~:text=The%20Interruption%20Cost%20Estimation%20(ICE)%20Calculator%20%2C%20a%20Berkeley%20Lab,economic%20costs%20of%20power%20interruptions.

[2] The regression models underlying the ICE Calculator's calculations may use as many as 23 variables for Medium and Large Commercial & Industrial (C&I) customers, and 22 variables for both Small C&I and Residential customers (See tab "Model" in PG&E Workpaper, RM-RMCBR-6).

[3] D.22-12-027, pp. 31, 32.

[4] Literature on electric reliability highlights biases in contingent valuation survey-based cost estimates that the ICE calculator is based on. PG&E's \$3.17/CMI translates to a cost per unserved kWh of \$4.50 for residential customers in California, which is significantly higher—about 1,223%—than the upper

The ICE calculator calculates the costs per event and unserved kWh for medium and large C&I, small C&I, and residential sectors by first applying the appropriate coefficients from the probit and generalized linear model (GLM) outputs. This is where the use of regression model outputs ends. The calculator then divides these costs per event by the "SAIDI value", to derive the cost per Customer Minutes Interrupted (CMI) for each customer class.[5] Finally, a weighted average of the aforementioned outputs is obtained by using the "number of customers" by sector. Through this method, PG&E's use of ICE calculator arrives at a combined cost of $3.17 per CMI (2023) for all customers, which it subsequently uses to quantify electric reliability costs across its electric risks.

PG&E argues that updating the ICE Calculator is premature due to the outdated data and assumptions of the current model and notes the challenges in determining the appropriate explanatory variables and their granularity.[6] PG&E further states that while it may be straightforward to input the number of customers at an appropriate granularity (for example, by fire-risk based geographic tiers), it is unclear what to assume for other explanatory variables and their granularity.[7]

TURN recognizes that, while the ICE 2.0 update, expected by the latter half of 2024,[8] is likely to yield more refined reliability metrics based on updated data and assumptions, immediate incremental improvements should not be delayed for the sake of a perfect solution. A key enhancement would be recalculating electric reliability using more detailed customer location data, reflecting the highly locational nature of electric reliability metrics such as service interruptions (See **Table 1** below). TURN also highlights that the variables used in the ICE Calculator's regression models, referred to as explanatory or independent variables, differ from

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market-based estimate from a well-cited 2021 study in "Energy Economics" suggesting costs range from $0.12 to $0.34 per kWh unserved across the US (California-specific: $0.23/kWh unserved). Reference: https://www.sciencedirect.com/science/article/pii/S0140988321001754?casa_token=7SYDpDibb9YAAAAA:FbWiwVBj1biwg4tvJyECQ-_A8rNvO5pwV6EmWN4PxUhqhCBpUy1iXG_t-mSh1KKhTpI01gPKuhtp

[5] PG&E RAMP Report, p. 2-15, Table 2-6 - PG&E uses territory-wide SAIDI value of 120 (2013-2022)

[6] PG&E RAMP Report , p. 2-57, lines 12-22.

[7] PG&E RAMP Report, p. 2-57, lines 31, 32. Although PG&E emphasizes household income as a "significant contributor" (p. 2-58) in the ICE Calculator's reliability value, the impact of income is relatively moderate (compared to, say, the outputs' sensitivity to SAIDI values). For instance, using PG&E's median California income of $56,862 results in a CMI of $3.170, whereas 2022 incomes at the 10th percentile ($29,000) and 90th percentile ($305,000) yield CMI values of $3.167 and $3.197, respectively (https://www.ppic.org/publication/income-inequality-in-california/).

[8] PG&E RAMP Report, p. 2-57, lines 23-25.

"global variables" like the number of customers and/or SAIDI values. These global variables are applied after model outputs are generated and can be adjusted to the specific granularity of geo-tier, tranche, or circuit segment without impacting the regression results.[9]

SPD requested that PG&E recalibrate its risk scores by geographic tiers, specifically the High Fire-Threat District (HFTD) Tier 3-Extreme, Tier 2-Elevated, NONHFTD-EPSS, and NONHFTD-NONEPSS, due to the differentiated Customer Minutes Interrupted (CMI) values reflective of the specific risks and service reliability in each area.[10] Additionally, PG&E was asked to implement the 4 new monetized values of electric reliability consequences to the Reliability Attribute for specific risks including Electric Transmission System-wide Blackout, Failure of Electric Distribution Overhead Assets, Failure of Electric Distribution Underground Assets, and Wildfire with PSPS and EPSS, which PG&E suggested would be tentatively available by end of September.[11] TURN notes that we have not evaluated the latter part of SPD's request, and any subsequent responses from PG&E.

As part of TURN's discovery, we received data on SAIDI distribution and observed significant variations in SAIDI values across the four geographic tiers and among different customer types.[12]

Table 1. Tier-specific SAIDI values (2016-2022 Average)

Customer Category	HFTD Tier 2 Elevated	HFTD Tier 3-Extreme	NONHFTD-EPSS	NONHFTD-NONEPSS
Small Commercial & Industrial (C&I)	454	613	179	103
Medium and Large Commercial & Industrial (C&I)	376	535	152	94
Residential	356	517	139	80

The first part of SPD's request involved the inclusion of the number of customers by the four geographic tiers and resulted in differentiated $/CMI values that reflect the specific risk and service reliability in each area. TURN recommends that the geographic-tier-based $/CMI values,

[9] See tab "Model" and respective variables used in PG&E Workpaper, RM-RMCBR-6.

[10] Response to SPD-002-Q001(a-d)

[11] Response to SPD-002-Q003

[12] Response to TURN-03-Q002b (PG&E noted in its response that the outage to customer mapping dataset only includes outages from May 2015 onwards. Consequently, the historical average of SAIDI is computed for the years 2016 to 2022, rather than the initially requested span from 2013 to 2022)

computed using the varying number of customers per tier, be further refined by incorporating the differentiated average SAIDI values (as opposed to a uniform SAIDI of 120), as shown in Table 2 below.

Table 2. Adjusted $/CMI(2023) by geo-tier based on number of customers and average regional SAIDI values (TURN)[13]

	Number of Customers			$/CMI (2023)	
Geographic Tier	**Residential**	**Small C&I**	**Medium and Large C&I**	**$/CMI (2023) * (SPD)**	**$/CMI (2023) w. regional SAIDI** (TURN)**
PG&E - HFTD Tier 3-Extreme	315,786	29,975	5,168	1.46	1.65
PG&E - HFTD Tier 2-Elevated	152,264	11,237	1,567	2.04	0.62
PG&E - NONHFTD-EPSS	1,143,635	115,614	33,122	2.92	1.27
PG&E - NONHFTD-NONEPSS	3,349,740	312,761	124,103	3.40	3.78
			Weighted Average	**2.46**	**1.83**

*Based on DR SPD-PGE-2024-RAMP-002 and **Based on Response to TURN-03-Q-2. b (avg. SAIDI 2016-2022)[14]

As shown in Table 2, incorporating SAIDI values by geographic tier enhances the accuracy of $/CMI results and reduces the weighted average from 2.46 $/CMI to 1.83 $/CMI by reflecting unique interruption profiles based on historical, tier-specific SAIDI data (2016-2022) provided by PG&E.

TURN's Recommendation

TURN suggests a more nuanced application of the ICE Calculator by incorporating customer location data, at a minimum by geographic tiering, and potentially at more granular levels such

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[13] See TURN Workpapers: Module_1-Estimate_Interruption_Costs_v2.0_HFTD Tier 3-Extreme_avg SAIDI; Module_1-Estimate_Interruption_Costs_v2.0_PG&E - HFTD Tier 2-Elevated_avg SAIDI; Module_1-Estimate_Interruption_Costs_v2.0_PG&E - PG&E - NONHFTD-EPSS_avg SAIDI; Module_1-Estimate_Interruption_Costs_v2.0_PG&E - PG&E - NONHFTD-NONEPSS_avg SAIDI. These TURN workpapers can be accessed at: https://theutilityreform-my.sharepoint.com/:f:/g/personal/ryanagiba_turn_org/EvoolwteS9lHmda2w1ssLDkBPFQ0AU6b_skFeEe3mUq-7w.

[14] PG&E Response to DR TURN-03-Q002b provides SAIDI values for the year 2022 and average SAIDI (2016-2022) by geo-tier. The latter values (i.e. 2016-2022 avg SAIDI) were used in Table 2.

as tranche and circuit segment levels, where feasible. For electric risks where the tranches are not broken at the level of geographical tiers, the use of proxies, such as historical reliability impact by spatial classification, may be appropriate.[15] TURN recognizes the potential challenge in assessing electric risks for tranches that do not directly correspond to geographic tiers.[16] In such cases, we recommend a transparent and consistent framework to ensure that electric reliability assessments accurately reflect the unique risks and service reliability across different regions within PG&E's territory.

TURN believes that a geo-tiered evaluation of $/CMI, using tier-specific average SAIDI values provides more accurate results by considering the varying risk profiles and SAIDI data across different geographic tiers. Using this approach, TURN recommends using the more representative average of 1.83 $/CMI (2023) based on data provided in Table 2.

2. PG&E's Arbitrary Application of California-Specific Adjustments Is Contrary to D.22-12-027 and Results in an Unreasonable Value of Statistical Life (VSL)

D.22-12-027 states that each Investor-Owned Utility (IOU) must calculate the Safety Attribute using one of two prescribed methods: 1) Apply the latest published Department of Transportation (DOT) Value of Statistical Life (VSL), adjusted to the base year of their respective Risk Assessment Mitigation Phase (RAMP) filing, or 2) Choose an alternative VSL from within a range provided by the United States Department of Health and Human Services (HHS), accompanied by a sensitivity analysis to evaluate the Cost-Benefit Ratio (CBR) impact in comparison to the standard DOT VSL.[17]

PG&E does not follow the clear instructions in D.22-12-027. Instead, PG&E opts for a hybrid approach that does not comply with either of the alternatives in D.22-12-027. Rather than simply updating the DOT value using DOT's prescribed data, it adds other California-specific inputs in a way that is at odds with the DOT's methodology. Specifically, PG&E applies California-specific income and wage multipliers to the nationwide DOT VSL calculation to increase the VSL from $13.2 million, the adjusted 2023 base year value under the DOT methodology, to $15.2 million.[18]

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[15] PG&E Response to SPD-03-Q003b, suggests the use of a proxy measure to estimate reliability impact from ignition spread, which is currently not evaluated by geo-tiers.

[16] PG&E Response to SPD-02-Q001 (Supp01).

[17] D.22-12-027, p. 63, ordering paragraph 1.

[18] PG&E RAMP Report, p. 2-10 to 2-11.

PG&E argues that the state's higher income and inflation rates justify this approach.[19] However, PG&E's method is wrong, as DOT guidance makes clear. To correctly apply a California-correction, you would need a meta-analyses of California-specific VSL estimates, and then update them for the base year as provided in the DOT guidance. That guidance emphasizes that "Prevention of an expected fatality is assigned a single, nationwide value in each year, regardless of the age, income, or other distinct characteristics of the affected population."[20] The guidance further notes and provides a methodology to "adjust the VSL to the base year used in the analysis". In fact, the DOT Guidance provides exact links to national inflation and real-income data in footnotes 10 and 11 of the guidance, presumably to avoid using incorrect base year adjustment.

The DOT approach respects the complexity of VSL determinations by incorporating diverse datasets that likely include California populations but are not limited to them. The DOT's $9.1 million VSL estimate for 2012 is based on the average VSL from 9 selected meta-analyses using the Bureau of Labor Statistics' (BLS) Census of Fatal Occupational Injuries (CFOI).[21] Typically, VSL estimates, based on population-level surveys or contingent valuation analyses, inherently factor in variables such as age, income, and wealth, making them representative of a nationwide valuation. Thus, aside from adjusting for inflation, there is no need for further escalation of the VSL as it encompasses a comprehensive national perspective.

Simplistic adjustments based on the use of state-level economic data like CPI and median wages leads to biased or inaccurate VSL estimations. Furthermore, the VSL study referenced by PG&E to justify its California-specific adjustment, emphasizes the need for using comprehensive and detailed demographic, occupational, and economic data—including industry-specific risks, socio-demographic variables like age and ethnicity, and job-related factors such as wages and work experience—to potentially enhance the accuracy and relevance of VSL adjustments within California.[22] Applying a constant ratio-based adjustment to the nationwide Value of Statistical

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[19] PG&E RAMP Report , p. 2-9, lines 24-26 and p. 2-10, lines 1,2.

[20] Departmental Guidance: Treatment of the Value of Preventing Fatalities and Injuries in Preparing Economic Analyses, March 2021, p. 4, found at: https://www.transportation.gov/sites/dot.gov/files/2021-03/DOT%20VSL%20Guidance%20-%202021%20Update.pdf

[21] Departmental Guidance: Treatment of the Value of Preventing Fatalities and Injuries in Preparing Economic Analyses, March 2021, p. 6, Table 1.

[22] "Updating Value per Statistical Life Estimates for Inflation and Changes in Real Income" (Apr. 2021), available at: https://aspe.hhs.gov/sites/default/files/2021-07/hhs-guidelines-appendix-d-vsl-update.pdf

Life (VSL) estimate, using only wages and Consumer Price Index (CPI), introduces biases from omitted variables and lacks mathematical and logical soundness.

TURN's Recommendation

TURN recommends the use of $13.23 million as the 2023 VSL, based on escalation of the DOT VSL from 2012 ($9.1 million).[23]

Alternatively, analysis conducted by the California Air Resources Board (CARB), suggests a mid-point California-specific VSL of $9.0 million (2013) which translates to $12.33 in 2023 dollars, after applying an adjustment factor (1.37) based on California-specific CPI-U.[24] [25]

3. Risk Averse vs. Risk Neutral Scaling Functions

3.1. PG&E Has Not Demonstrated the Reasonableness of Its Extreme Scaling Function

The risk scaling function PG&E proposes to use is categorized into three distinct regions based on financial levels and the degree of risk adjustment. Slope 1, ranging from $0 to $10 million monetized levels of attributes, represents the risk-neutral region where a linear, 45-degree progression indicates a consistent and proportional adjustment to risk across this range. Slope 2, from $10 million to $1 billion, is termed the "insurance-based" risk region, characterized by a steeper slope of 2.0. Slope 3, from $1 billion to $1.25 billion, termed as the "Capital-Markets" risk region, displays a very steep slope of 7.5, signifying an almost infinite willingness to pay (or a potential squared or cubic convex function) at higher monetized levels of an attribute.

PG&E's graphical depiction of its scaling function (the figure below on the left) is not drawn to scale and masks how drastically it increases consequence values compared to a risk neutral function, particularly in the third risk region, as shown in the to-scale figure on the right.

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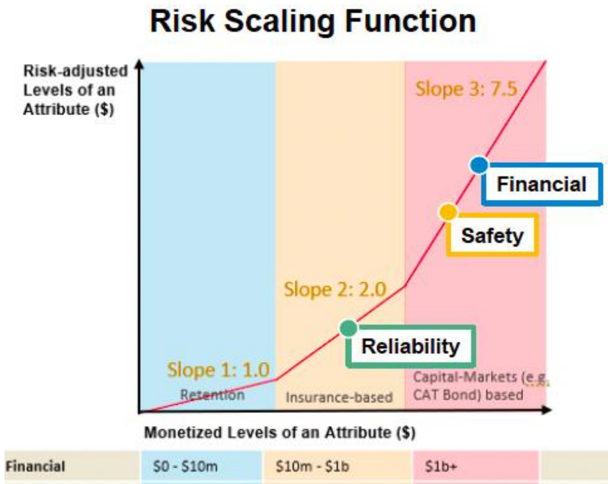
[23] PG&E Workpaper, RM-RMCBR-6 (Rows 3-26)

[24] "Review of Mortality Risk Reduction Valuation Estimates for 2016 Socioeconomic Assessment", 2016, p. 17. https://ww2.arb.ca.gov/sites/default/files/2021-10/SCAQMD%20Mortality%20Risk%20Reduction%20Valuation.pdf

[25] Use of a California-specific CPI-U escalator is appropriate for a California-specific VSL.



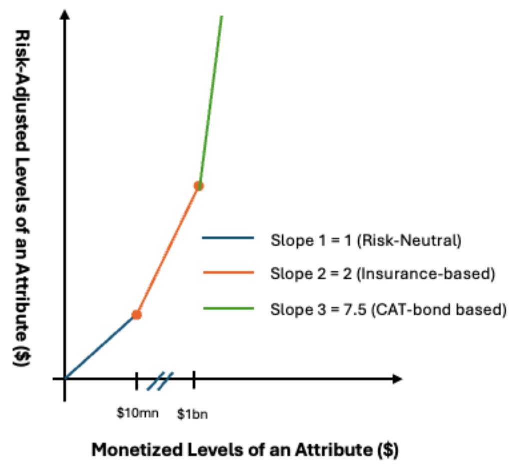


Figure 2. PG&E's Depiction of its Risk Scaling Function (Post-Filing Workshop, Slide 36)

Figure 1.PG&E's Risk Scaling Function, drawn to scale.

PG&E has not justified its use of such an extremely convex scaling function compared to a risk-neutral function.

PG&E avoids the central question of whose risk preference is being expressed. PG&E is a regulated monopoly, and it is the interests of the ratepayers and the general public that are relevant. Because PG&E is spending ratepayer money, the scaling function should reflect the ratepayers' attitudes toward uncertainty. The Commission has made it clear that the utilities' risk models should not be based on shareholders' financial interests and should remove such considerations from their decision-making frameworks.[26]

There is no reason to believe that the people of California, or a single utility's ratepayers, can be characterized as having a single preference for risk or attitude toward uncertainty. The preference will be personal and variable. PG&E has not addressed the difficulty of determining the preferences of groups as large as the California public or the diverse body of PG&E ratepayers. Nor has PG&E shown that its scaling function betters reflects the attitudes of these groups to risk than a linear scaling function.

To the contrary, PG&E does little to disguise the fact that its "market-based" approach is based not on its customers' risk attitude but based on PG&E's "risk management objective,"[27] which,

[26] D.16-08-018, p. 123.

[27] PG&E RAMP Report, p. 2-20.

as an investor-owned utility, is indisputably driven by the financial interests of the company's shareholders. PG&E's three-tiered "risk financing strategy" is based on the "management of losses *by firms*,"[28] and is not an approach to risk that many of its customers would recognize. Participants in the "cat bond" market are typically institutions, not individuals. While individuals and households often purchase insurance, the reasons for doing so vary as does the coverage chosen by each individual. The range of insurance products available reflect consumers with a broad range of preferences.

In addition, it is important not to confuse risk-aversion with aversion to bad outcomes. Most people would spend money to avoid a bad outcome. Under a risk neutral function, a utility's ratepayers would be expected to spend twice as much money to avoid twice as many deaths or twice as much financial loss. But PG&E's scaling function implies preferences that most people are unlikely to share, namely that not every dollar and not every life is valued equally. For example, PG&E's function values a reduction of 11 fatalities to ten fatalities at least ten times more than a reduction of one fatality to zero. While everyone wants to avoid catastrophic events, PG&E has not made the case for why ratepayers should be expected to pay ten times as much to avoid one fatality if that fatality is part of an 11-fatality event, as opposed to a single fatality event.

The impact of PG&E's scaling function is to make mitigation activities appear more valuable than they would otherwise be if they were evaluated using a linear scaling function. This serves the company's financial interest in justifying higher expenditures, including higher capital spending on which the utility's shareholders collect a profit.

In short, PG&E and its shareholders may be as risk averse as its scaling function implies, but PG&E has utterly failed to demonstrate that it is fair to ascribe the same level of risk aversion to its customers who are paying the bills.

3.2. Consistent with D.24-05-064, PG&E's GRC Showing Should At Least Supplement Its CBR Calculations with CBRs Based on a Linear Scaling Function

Notwithstanding TURN's concerns with PG&E's approach, PG&E is free to present the results of its risk analysis using its preferred scaling function. It is up to the Commission whether to view PG&E's results, including its CBRs, as reasonable and useful for decision-making purposes. The preceding section offers reasons why the Commission should be skeptical of relying on modeling results based solely on PG&E's preferred scaling function and why understanding how PG&E's approach compares to a risk-neutral alternative. However, without running the data through PG&E's models, it is often difficult to predict for a given mitigation

[28] *Id.*, p. 2-22 (emphasis added).

how much PG&E's preferred scaling function will affect the CBR calculation compared to a risk-neutral scaling function. The only reliable way to understand this impact is for the utility to present, for comparison purposes, CBRs using a linear scaling function.

In D.24-05-064, the Commission held that utilities basing their analysis on a convex scaling function as a means of addressing uncertainty must supplement their analysis by also presenting risk-adjusted attribute levels using a linear scaling function.[29] This requirement applies to PG&E because the utility readily admits that it uses a convex scaling function to address uncertainty concerning the frequency and consequences of catastrophic events.[30]

D.24-05-064 was effective on May 30, 2024, after the May 15, 2024 due date for PG&E's RAMP submission, and therefore does not apply to this RAMP proceeding. However, the revisions to the RDF indisputably went into effect on May 30, 2024 and thus apply to all events occurring after that effective date, including the GRC that PG&E will file in May 2025.

Nevertheless, in response to TURN discovery, PG&E asserts that it is not required to abide by the requirements of D.24-05-064 and provide CBRs based on a linear scaling function.[31] PG&E contends that risk modeling requirements that do not apply to a utility's GRC unless they also applied to the utility's RAMP.[32]

The Commission made no such statement in D.24-05-064, nor in any other decision. If this were the Commission's intent, it could have said so in D.24-05-064. But the Commission did not delay the effectiveness of any of the decision's provisions. This silence contrasts starkly with D.22-12-027, in which the Commission expressly delayed the implementation of the wholesale changes in the new RDF adopted in that decision – transitioning from the MAVF to the CBA approach -- specifying that the new approach would apply beginning with this PG&E RAMP.[33]

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[29] D.24-05-064, p. 97, and Appendix A, p. A-8, Row 7. The decision states on page 97: "We also agree with MGRA that use of the risk scaling function is not necessary to address uncertainty. The concern with uncertainty can be addressed through the topic of tail risk, as addressed in Rows 5 and 24 of the RDF and affirmed with this decision (see sections 7 and 8 above). *To ensure that IOUs will transparently demonstrate to decisionmakers that the risk scaling function is not being used to address uncertainty in the model*, but instead is focused on expressing the axiological preferences of the utility, we include additional language to Row 7 that draws from TURN's proposal." (Emphasis added.)

[30] PG&E RAMP Report, p. 2-2 to 2-3. *See also* pp. 59-60, where PG&E acknowledges that its scaling function addresses at least one type of uncertainty ("epistemic" uncertainty).

[31] Response to TURN DR 11, question 1.

[32] *Id.*

[33] D.22-12-027, p. 63.

PG&E has been aware of the modified Row 7 requirement since May 2024 and has had, and continues to have, ample time, to address it in its upcoming GRC. Unlike the transition to the CBA ordered in D.22-12-027, the requirement to supplement its CBR calculations with values based on a risk neutral function does not require development of an entirely new modeling framework. Notably, PG&E states that it has no objection to providing alternative *risk scores* based on a linear scaling function.

As the Commission stated in D.24-05-064, this CBR information is necessary to "transparently demonstrate to decisionmakers that the risk scaling function is not being used to address uncertainty in the model . . ..."[34] This requirement does not require PG&E to endorse the CBR results based on a linear scaling function -- only to provide those alternative results as a matter of transparency and for comparative purposes.

TURN urges PG&E to re-visit its position and to announce that it will comply with the clear requirements of D.24-05-064 in its GRC submission.

4. PG&E's GRC Filing Should Allow the Commission and Intervenors to Compare the Cost-Effectiveness of Alternative Mitigations on an "Apples to Apples" Basis

The purpose of utility risk modeling is to allow the utilities, Commission, and intervenors to assess, explore, and understand utility risk to then propose mitigations that balance risk reduction with costs. As the Commission stated "the objective of the S-MAP is to fulfill the state's policy of ensuring that the Commission and the energy utilities place the safety of the public and utility employees as the top priority, and for the Commission to carry out this priority safety policy consistent with the principle of just and reasonable cost-based rates."[35] Under D.22-12-027, a key output of this risk modeling is a cost-benefit ratio (CBR), which provides cost-effectiveness values for multiple mitigations.

The presentation of CBRs to-date by all the utilities, including PG&E, is misleading when alternative mitigations are capable of serving a similar risk mitigation purpose. Rather than calculating the cost-effectiveness of mitigations on an "apples-to-apples basis" whereby each mitigation is assumed to be deployed to the same risk area, the utilities calculate CBRs based only on the utility-specific *proposal,* which usually entails deployment of its preferred mitigation to the highest-risk areas or tranches, while other mitigations are assumed and modeled as mitigating risk to other, lower-risk areas. These calculations do not lend themselves to direct comparisons of CBRs. CBRs calculated based on this methodology are thus only relevant to the

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[34] D.24-05-064, p. 97.

[35] D.18-12-014, p. 6.

utility's proposal, rather than alternatives which would deploy alternative mitigations to the same risk area or tranche as the utility's proposal.

Ideally, utilities would calculate CBRs based on deploying mitigations to the same tranche and same number of miles which would allow for an apples-to-apples comparison of cost-effectiveness. For example, such apples-to-apples comparisons would be appropriate for competing wildfire system hardening alternatives, such as covered conductor and undergrounding, and for replace versus repair alternatives for gas and electric infrastructure.

At minimum, PG&E should allow the Commission and intervenors to conduct these comparisons at their own accord, with the ability to examine multiple alternatives. For example, TURN appreciates that, several weeks after TURN requested it, PG&E created a spreadsheet tool that allowed us to compare the cost-effectiveness of system hardening initiatives when deployed to the same tranche or risk area, as well as modify inputs like the number of miles and unit costs.[36] In its GRC, whenever alternative mitigations can be deployed to reduce risk, PG&E should provide a similar tool with its workpapers for all top risk areas when it files its GRC. At a minimum, PG&E should be prepared to provide such a tool upon request to interested parties and the Commission within the customary 10 business-day data request cycle.

5. PG&E's Wildfire Risk Modeling

5.1. PG&E Inaccurately Estimates the Financial Consequences of Wildfire Risk

The financial consequence of wildfires is based primarily on the assumed number of structures destroyed multiplied by an assumption that each structure is worth $1 million.[37] This $1 million value per structure is based on the weighted average (by number of structures) from 2015-2017, which PG&E has maintained from its 2020 RAMP "given the high variability of average dollar damage per structure year to year."[38]

The $1 million per structure assumption is outdated and does not reflect a reasonable assumption. Indeed, 2017 was the only year in which this damage value reflected reality – in every other year from 2015-2022, the dollar damage per structure was less, in many years significantly less. From 2020-2022, the $1 million assumption overstated actual recorded data by an average of 324%.

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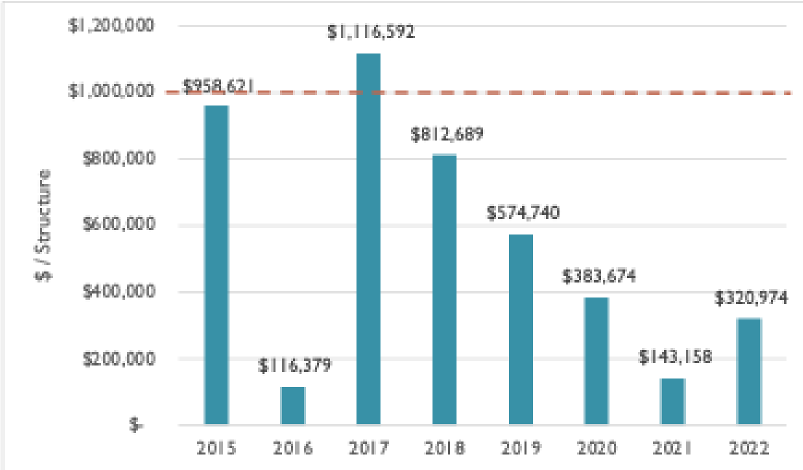
[36] This Excel tool was sent via email to TURN and is called "WLDFR OH, UG comparison tool_Final_7-15-24.xlsx."

[37] EO-WLDFR-7_CalFire Large+ Fires 2015-2022, tab "Consequence_Destructive."

[38] Response to DR TURN-5, question 2(f).

Figure 3. Dollar Damage per Structure Destroyed (Recorded)



A more realistic assumption that incorporates significantly more data is for PG&E to use the weighted average (by number of structures) from 2015-2022 – approximately $723,000.[39] This is a more accurate and robust estimate than arbitrarily retaining the 2015-2017 weighted average from the 2020 RAMP.

Incorporating this recommendation has a significant impact on the baseline wildfire risk score. **By itself, this change lowers the wildfire risk score by 26% in each year from 2027-2030**.[40] Making this change would also generally reduce the CBRs for PG&E's wildfire mitigations as there would be less risk to mitigate for the same cost.

5.2. PG&E Should Base the Mitigation Effectiveness of Covered Conductor on Recorded Data

To calculate the mitigation effectiveness of overhead hardening, which primarily consists of installation of covered conductor to replace bare conductor, PG&E relies on internal subject matter experts (SMEs). SMEs use judgement to categorize the ability of covered conductor to prevent a historical outage. Each category is then mapped to a corresponding mitigation percentage value.[41]

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[39] Response to DR TURN-5, question, 2, attachment 1.

[40] Response to DR TURN-8, question 1, attachment 2.

[41] Response to DR TURN-5, question 4a.

Table 3. Covered Conductor Mitigation Effectiveness Values used by SMEs

Name	Value
NONE	0%
LOW	20%
MEDIUM	40%
MEDIUM-HIGH	60%
HIGH	70%
VERY-HIGH	90%
ALL	100%

This results in an average mitigation effectiveness of 66% based on the drivers of outages examined.[42]

Probabilities assigned by SMEs, based on what is essentially a "best guess," may be a reasonable approach when no other data is available. However, this is no longer the case. PG&E alone has deployed over 1,100 circuit miles of covered conductor since 2018, while Southern California Edison (SCE) has deployed 4,400 circuit miles through 2022.[43] The utilities have also conducted significant laboratory testing of CC for several primary drivers of ignitions.[44]

Based on the extensive data collection accomplished to-date, the use of qualitative judgement from SMEs should be substituted with data-driven analysis on the actual performance of covered conductor. When PG&E has done such an analysis of ignition mitigation effectiveness on hardened circuits, it found a mitigation effectiveness percentage of 79%.[45] However, the utility does not believe the statistic is accurate because covered conductor was installed recently and has not been subject to degradation, some has been deployed in areas as part of wildfire rebuild which has a different risk profile, the utility deploys undergrounding in high strike tree risk areas which could skew the data, and the utility cannot always locate the exact location of an outage to determine if the portion of the circuit that caused it was covered or not.[46]

There are always some challenges with data collection and PG&E should seek to overcome them. It is, at best, unfortunate that PG&E has spent more than $1 billion on a program to install

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[42] PG&E Workpaper: EO-WLDFR-14_2015-2022_Estimated_CC&UG_Effectiveness_Workpaper, tab "Effectiveness Outputs."

[43] SCE 2023-2025 WMP, p. 880, Table CC-1, https://www.sce.com/sites/default/files/AEM/Wildfire%20Mitigation%20Plan/2023-2025/SCE%202023%20WMP%20R2-clean.pdf.

[44] SCE 2023-2025 WMP, p. 880.

[45] Response to DR TURN-6, question 4.

[46] Id.

covered conductor and yet does not appear able or willing to collect and make use of data on the performance of the program to more accurately estimate mitigation effectiveness.

Rather than the qualitative approach currently used, PG&E should base its mitigation effectiveness for covered conductor on the drivers of ignitions in its service territory combined with data from both PG&E's own system and SCE. At minimum, SCE has amassed a large amount of data on mitigation effectiveness by driver, which can be utilized to calculate more accurate mitigation effectiveness values relevant to PG&E's service territory.

5.3. PG&E Includes Inaccurate Assumptions that Overstate the Risk of PSPS

PG&E incorporates two inadequately supported assumptions regarding PSPS risk. Namely, PG&E overestimates the number of customer minutes of outage and understates the effectiveness of PSPS for mitigating wildfire risk. These flaws cause PG&E to understate the benefits of PSPS and overstate reliability impacts of PSPS. As a result, PG&E's baseline risk score for the Wildfire Risk – which incorporates risk reduction and consequences of PSPS and EPSS - is overstated.

PSPS Customer Minutes of Outage

In order to estimate the "risk" of PSPS outages on customers, PG&E uses a "lookback" approach. This approach applies the current PSPS criteria to weather conditions that PG&E's service territory has experienced in the past and identifies the locations where the PSPS criteria would be met."[47] PG&E states the "reliability consequence of a PSPS risk event is modeled with an exponential distribution whose mean is based on the average of customer minutes interrupted per PSPS lookback event."[48] This is then multiplied by a value of lost load (VOLL) to determine consequences in dollar terms.

Examination of historical data on the *actual* deployment of PSPS shows that PG&E's methodology significantly overestimates *modeled* PSPS impacts. For example, PG&E's model includes the year 2023, and estimates <u>722 million</u> customer minutes of outage due to PSPS. Yet the *actual* number of customer minutes of outage in 2023 was <u>only 5.3 million</u>.[49] This represents a difference of over 13,000%. This discrepancy means PG&E's estimate is simply not realistic or an accurate representation of PSPS outage minutes, as shown in the figure below.

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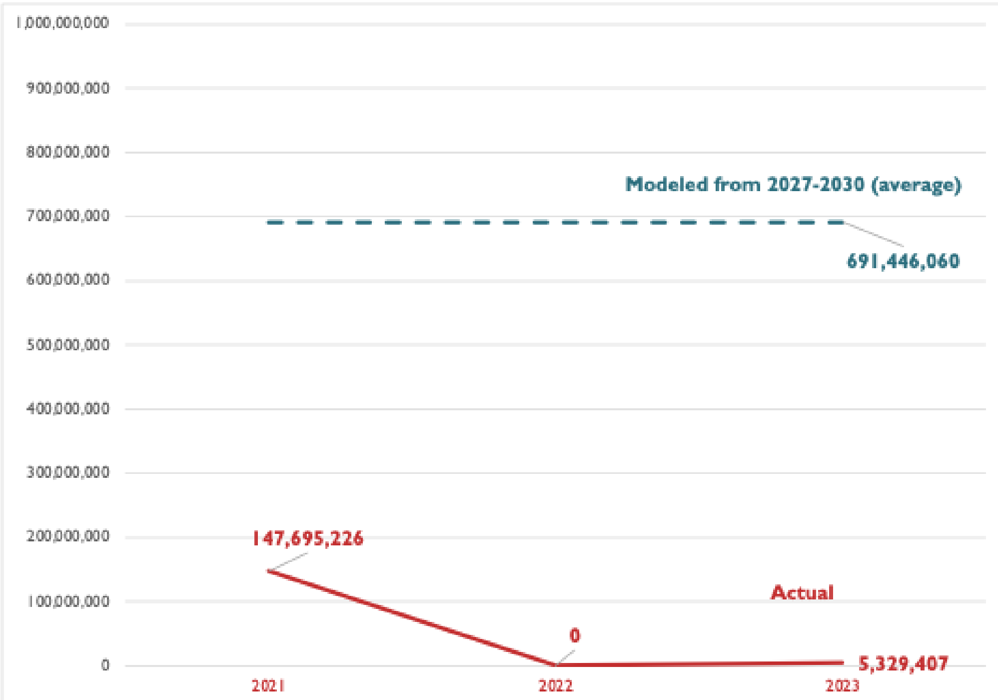
[47] PG&E RAMP Application, PG&E-4, p. 1-9.

[48] Response to DR TURN-2, question 4.

[49] Response to DR TURN-12, question 1.

Figure 4. Forecast Modeled Customer Minutes of Outage versus Actual Customer Minutes of PSPS Outage, 2021-2023



We note that in 2019 and 2020 (not shown in the figure) PSPS customer minutes were above the modeled average; however, we believe these years are not relevant to future forecasts of PSPS outages. First, these years used different PSPS protocols than the one currently in place (the latest was established in 2021).[50] Second, they do not reflect the operational improvements PG&E has made in implementing PSPS, particularly after 2019 when PG&E unnecessarily implemented PSPS to millions of customers in the midst of its bankruptcy using inadequate operational practices.[51]

This improvement is shown in the figure below, which shows the PSPS customer minutes of outage normalized for wildfire risk in each year. Normalization is accomplished by dividing annual PSPS outage minutes by the number of red flag warning circuit mile days, a measure of wildfire risk relevant to the implementation of PSPS.[52]

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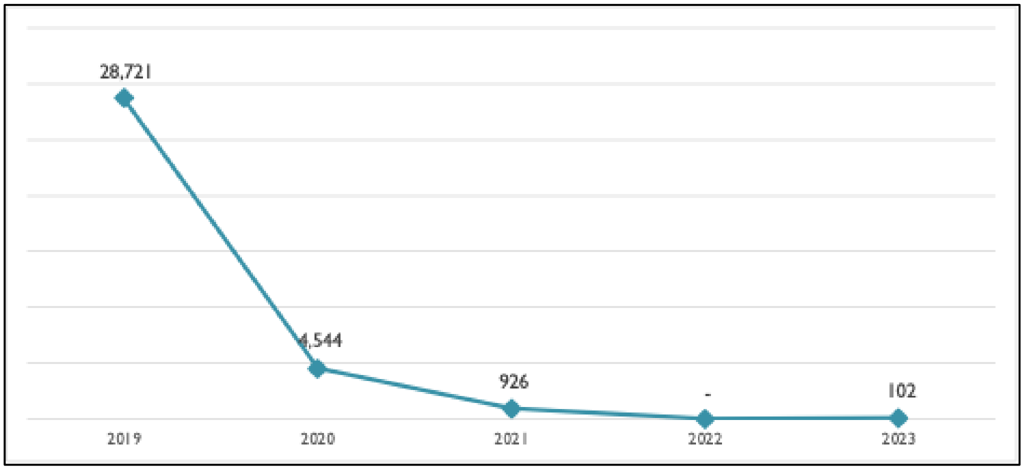
[50] Response to DR TURN-12, question 2.

[51] CPUC, https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-holds-pge-accountable-for-flawed-implementation-of-fall-2019-psps-events.

[52] "A "Red Flag Warning (RFW) Circuit Mile Day" is intended to capture the duration and scope of the fire weather that year. It is defined on page 5 of the 2020 WMP Guidelines to be calculated as the number of circuit miles that were under a RFW multiplied by the number of days those miles were under said RFW. For example, if 100 circuit miles were under a RFW for 1 day, and 10 of those miles

Figure 5. Actual PSPS Customer Outage Minutes Divided per Red Flag Warning Circuit Mile Days, 2019-2023



Normalized for wildfire risk, PSPS outage minutes have decreased by nearly 100% in 2023, compared with 2019.

PG&E's GRC filing should reflect a better estimate of customer minutes of outage for the general rate case period, incorporating the reality that PG&E has become significantly more targeted in its use of PSPS, and that PG&E's current modeling of customer outage minutes does not reflect a reasonable forecast of this risk.

TURN recognizes there are likely several ways to derive a more reasonable estimate. The table below utilizes the statistics discussed above – RFW circuit mile days and outage minutes per RFW circuit mile days – to calculate a reasonable range that PG&E's forecast should likely fall into, with the "maximum" amount representing an upper bound. This upper bound could be used to cap PG&E's statistical distribution curve, which is also a feature of PG&E's model that may need to be re-considered.[53]

As stated above, 2021-2023 are the most relevant years for a forecast of outage minutes per RFW circuit mile day, and we exclude 2022 because there were zero minutes of PSPS outages which may have been an anomalous year.

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were under RFW for an additional day, then the total RFW circuit mile days would be 110." Office of Energy Infrastructure Safety, https://energysafety.ca.gov/wp-content/uploads/docs/misc/docket/336483109.pdf.

[53] As stated above, PG&E uses an exponential distribution which may not be appropriate.

Table 4. Average and Maximum PSPS Customer Outage Minutes Based on Historical Data

	Maximum	Average
RFW Circuit Mile Days (2018-2023)	294,176	163,930
Outage Minutes per RFW Circuit Mile Day (2021, 2023)	926	514
PSPS Customer Outage Minutes	272,415,051	84,249,135

PSPS Mitigation Effectiveness

PSPS should have a very high effectiveness in mitigating wildfire risk, particularly for the most significant fires that happen due to risky wildfire weather likely to trigger a PSPS event. PG&E's estimate of PSPS effectiveness differs by type of fire – destructive, large, and small – shown below.[54]

[54] See PG&E RAMP, p. 1-36. "Destructive: Defined as a CPUC Reportable fire that burns 300 or more acres and destroys no less than 100 structures. Large: Defined as a CPUC-reportable fire that burns 300 or more acres, but destroys < 100 structures. Small: Defined as a CPUC-reportable fire that burns fewer than 300 acres."

Table 5. PG&E PSPS Effectiveness Assumptions and Derivation[55]

Outcome	PSPS Effectiveness	Notes
RFW - Destructive Fires	90.00%	This is based on the lookback analysis of applying the 2021 PSPS guidance to 2012-2020 historical fires with the detected size greater than 1000 acres. The 2021 guidance could have prevented 100% of historical destructive fires during RFW in 2015-2020. However, because the 2021 guidance is calibrated using historical fires, we assume that there could be 1 destructive fire over the same time period that won't be prevented, so the effectiveness is 9 / (9 + 1) = 90%
RFW - Large Fires	50.00%	Percentage of large fires occurred during RFW that are identified as catastrophic based on 2021 PSPS guidance. This is not perfect because the set of fires in Fire Data are only those with detected final size greater than 1000 acres, and there could be large fires that with detected size less than 1000 acres that are below guidance. However, since most of the wildfire risk is accounted for by destructive fires so the error should be small.
RFW- Small Fires	49.71%	This is based on 2020 hazards and damages data. There was 257 damages and hazards found during 2020 PSPS events, multiply that by ignition rate of 7.65% (estimated based on the veg and equipment ignition rate per outage) , and then the likelihood of ignition becoming small fires in HFTD during RFW at 85.48% (estimated based on CPUC reportable 2015-2020) to get the number of avoided small fires being .0765 * 257 * 85.48% = 16.8058. The observed small fires is 17 in 2020, so the effectiveness is 16.8/(16.8+17)=0.497

As PG&E states in the table, the 90% effectiveness for destructive fires is determined by arbitrarily assuming there would have been one fire missed by the PSPS protocol over the historical period examined, despite the fact that this is not the case. Given that there were 10 destructive fires over the period, this resulted in PG&E's 90% effectiveness statistic.

There are two problems with this methodology. First, it is sensitive to the number of fires caused in the historical period, which leads to some absurd conclusions. For example, if there had been 20 destructive fires over the period, adding one missed fire would result in a 95% mitigation effectiveness (19/20); if there had been just 2, it would be 50% (1/2). Second, the assumption that PSPS would miss one destructive fire is arbitrary and not based on data. PSPS criteria is specifically targeted to identify exactly the conditions in which a destructive or large fire is likely to occur.

Furthermore, from a common-sense understanding of PSPS as a wildfire mitigation, PSPS *should* have a near 100% mitigation effectiveness since it involves shutting off power during high-risk conditions that cause large and destructive fires. Given that PG&E's modeling assumption of including one "missed" destructive fire is arbitrary and unsupported, as well as a common-sense judgement regarding the effectiveness of shutting off power during high-risk

[55] PG&E Workpaper: EO-WLDFR-M021_EPSS and PSPS, tab "IN2_PSPS_Effectiveness."

conditions, the effectiveness of PSPS for mitigating destructive fires should be revised to at least 95%.

Regarding the 50% mitigation effectiveness of PSPS for large fires, the relatively low mitigation effectiveness value is driven by a very limited amount of data. Namely, in the utility's analysis of ignitions that occurred on its system from 2015-2020, the analysis finds there were 2 large fires that occurred in 2017 that PG&E claims would not have been mitigated by PSPS – this was divided by a total of four large fires over the period (three large fires occurred in 2016, one of which would have been mitigated by PSPS according to PG&E). However, the analysis ignores 2019 and 2020 when no large fires occurred and PSPS was in place; it could be that PSPS prevented large fires in those years, which therefore don't appear in the data set.

Table 6. PG&E Large Fire PSPS Analysis[56]

Year	Mitigation Effectiveness	Notes
2015	Not included	No large fires
2016	100%	1 large that would have been mitigated by PSPS
2017	33%	3 large, 1 that would have mitigated by PSPS
2018	Not included	No large fires
2019	Not included	No large fires
2020	Not included	No large fires

Similarly, there were no large fires in 2021 or 2023, and one large fire in 2022.[57] From both a conceptual standpoint regarding how PSPS is implemented, as well as data over the several years as PSPS has been in place, PSPS effectiveness for large fires should be significantly higher than 50%.

There is a dearth of data on PSPS effectiveness simply because it is in place and avoiding fires that would have otherwise occurred. Absent a more data-driven approach, given the clear success of PSPS in avoiding large fires PG&E should assume at least a 90% PSPS effectiveness in mitigating large fires. Again, these fires occur under precisely the conditions PSPS protocols are tailored to identify.

[56] Analysis based on TURN-5, question 5, attachment 1.

[57] CPUC Ignition Database, https://www.cpuc.ca.gov/industries-and-topics/wildfires.

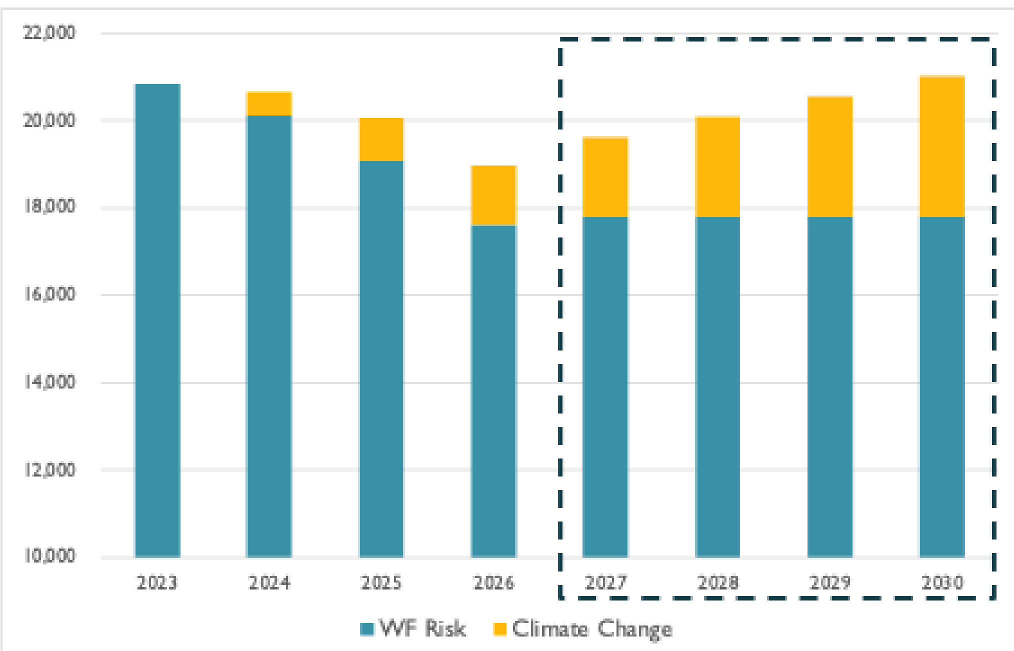
5.4. PG&E's Modeling of Climate Change Risk Is Not Reasonable

PG&E has attempted to incorporate the risk of climate change into its calculations of wildfire risk by increasing the number of ignitions expected to occur during RFW conditions as determined from climate change models, relative to a 2023 baseline:

> Climate impact is modeled as a % increase of ignitions occurring when a Red Flag Warning (RFW) is in place while keeping the total ignition frequency the same. The rate of increase is based on forecast of days above historical 95th percentile Fire Weather Index (FWI) [footnote omitted] provided by ICF climate center for 2030, 2050 and 2080 at Circuit Segment (CS) level for distribution in workpaper CC-CLIMT-14, and at Electric Transmission Line (ETL) level for transmission in workpaper CC-CLIMT-15.[58]

Incorporating climate change has a significant impact on total wildfire risk, comprising 9% of baseline wildfire risk in 2027 to 15% of baseline risk in 2030. Baseline wildfire risk increases by 18% due to climate change from 2023 to 2030.[59]

Figure 6. PG&E Modeling of Baseline Wildfire Risk and Impact of Climate Change



TURN has identified two issues with PG&E's climate change calculation.

[58] Response to DR TURN-5, question 1.

[59] Response to DR TURN-5, question 1(c).

1. The use of climate change models to derive increases in RFW ignitions is not only extremely complex, PG&E's and ICF's modeling assumptions are highly opaque and virtually impossible, at least in the context of a single RAMP proceeding, to replicate, verify, or determine whether the inputs are reasonable.
2. The calculation appears designed to increase the impact of climate change exactly through the rate case cycle (2027-2030), after which climate change impacts would remain constant or *decrease.* At minimum, this is counterintuitive. This finding further highlights the inappropriateness of incorporating this significant driver of wildfire risk as presented, without further Commission understanding and review.

The lack of transparency stems in part from the complexity of the analysis. PG&E utilized an ICF analysis that combines results of eight different climate change models, deriving numerical values that were then compared to a 2023 baseline.[60] The relative merits of this approach and examination of inputs and outputs of ICF's analysis are not possible to determine with the materials provided by PG&E,[61] and, in any event, would require greater time, resources, and expertise than is available or possible in a single RAMP proceeding. There are bound to be numerous nuances and assumptions that drive the results here, and these need to be examined for reasonableness.

To provide just one (relatively simple) example, PG&E/ICF chose the 95th percentile results from the SSP3-7.0 climate change model and compared this to a 2023 baseline. PG&E has not explained why it believes this is the most reasonable scenario and produces the most accurate results. This kind of impactful analytic decision appears to be replicated numerous times in the modeling.

[60] See PG&E workpaper: CC-CLIMT-14_WLDFR.

[61] Response to DR TURN-5, question 1(b).

Table 7. Shared Socioeconomic Pathway (SSP) Scenarios[62]

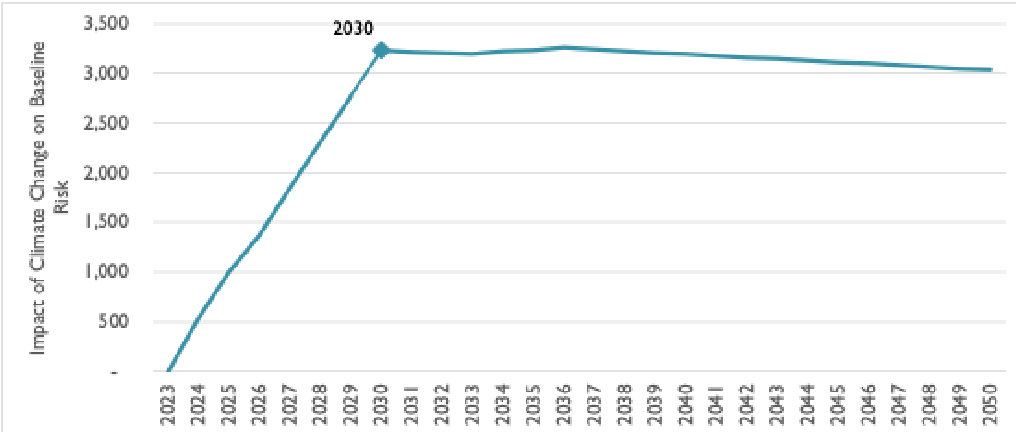
SSP Scenario	Summary Narrative	Temperature Change (2081–2100)	Sea Level Projections (2080-2100)
SSP1-1.9	Holds warming to approximately 1.5°C above pre-industrial levels with a slight overshoot, aiming for net zero CO2 emissions around mid-century.	1.0°C – 1.8°C (1.8°F – 3.2°F) Very Likely	For 1.5°C global warming
SSP1-2.6	Stays below 2.0°C warming relative to pre-industrial levels with net zero emissions targeted for the second half of the century.	1.3°C – 2.4°C (2.3°F – 4.3°F) Very Likely	For 2°C global warming
SSP2-4.5	Aligns with the upper end of current Nationally Determined Contributions (NDCs), predicting warming around 2.7°C by 2100.	2.1°C – 3.5°C (3.8°F – 6.3°F) Very Likely	For 3°C global warming
SSP3-7.0	No additional climate policies under a medium to high emission scenario, with particularly high non-CO2 emissions.	2.8°C – 4.6°C (5.0°F – 8.3°F) Very Likely	For 4°C global warming
SSP5-8.5	High emission scenario without additional climate policies, under a fossil-fuel-heavy development pathway.	3.3°C – 5.7°C (5.9°F – 10.3°F) Very Likely	For 5°C global warming

At this point, TURN simply cannot say whether this assumption is reasonable or what the implications of using other scenarios may be. The Commission and parties need significantly more time and exploration to determine how best to incorporate the climate change variable into risk calculations, particularly given its significant impact on the results.

Lastly, ICF's modeling results are highly counterintuitive. The following figure shows the annual impact of climate change on baseline wildfire risk. Climate change increases baseline wildfire risk at a rising linear rate through 2030, the end of the rate case period, and then has virtually no impact or *decreases* thereafter.

[62] NASA, https://sealevel.nasa.gov/ipcc-ar6-sea-level-projection-tool?psmsl_id=1476&info=true&data_layer=scenario.

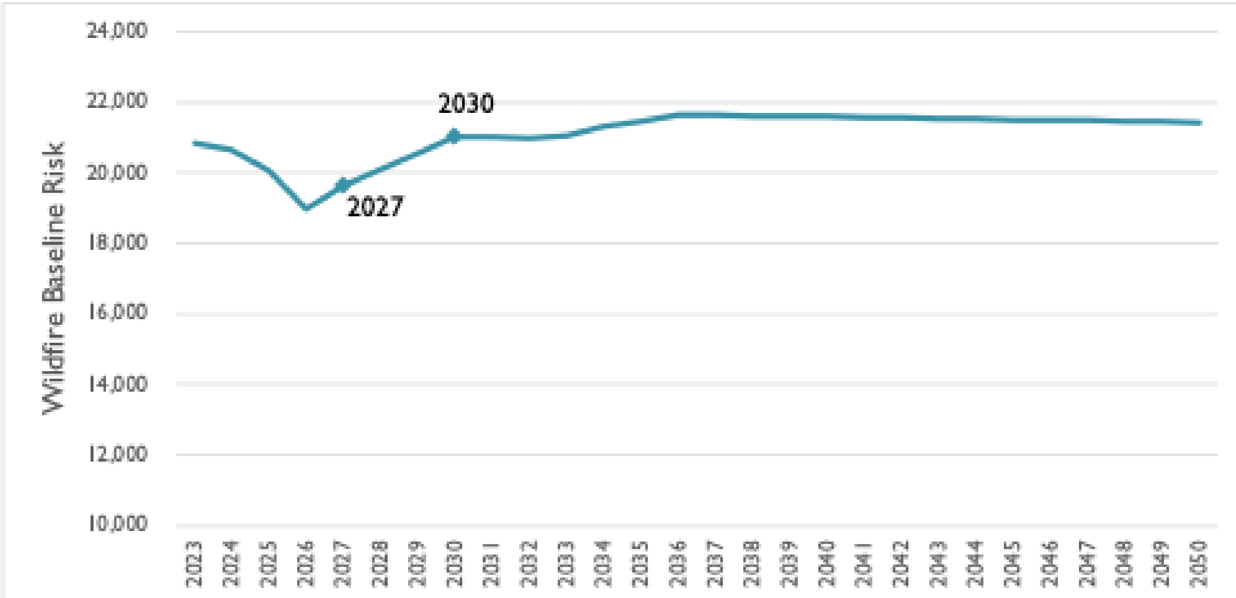
Figure 7. Annual Impact of Climate Change on Baseline Wildfire Risk Score (Risk Units) [63]



This impact is also seen in the wildfire baseline risk score below, which increases from 2027-2030 and then remains effectively flat thereafter. Note too that the impact of climate change completely erases all risk reduction achieved from 2023-2026 from undergrounding and other initiatives on which PG&E is spending billions and for which ratepayers, particularly those who are lower income, are incurring tremendous hardship.

[63] Response to DR TURN-8, question 1, attachment 2.

Figure 8. Wildfire Baseline Risk Score (Risk Units, 2023-2050) [64]



From a common-sense perspective about climate change, these results do not seem accurate, namely that higher temperatures result in a lower or flat increase in annual risk after 2030. PG&E sought to explain these results as follows:

> […]it is not unusual for FWI projections to decrease between two near-term time horizons, as precipitation, wind, and humidity are not increasing or decreasing linearly through time. FWI is a dynamic variable influenced by many different variables pulling it in different directions through time, but temperature will accelerate by late-century (2080) overwhelming any variability in the remaining variables.[65]

At minimum, this underscores that greater understanding and deliberation of these modeling results is required.

While aspects of PG&E's approach may be useful, it is not clear that PG&E's approach is accurate or robust enough to incorporate into the GRC to inform near-term investments. This issue affects all utilities and should be addressed more robustly in the S-MAP process.

In the meantime, while TURN does not oppose some climate change-based increase in risk being incorporated into PG&E's modeling between 2023 and 2030, PG&E's modeled increase cannot be verified, and it is frankly suspicious that climate change impacts should primarily affect the rate case cycle years (2027-2030) and erase all previous risk reduction gains, very likely leading

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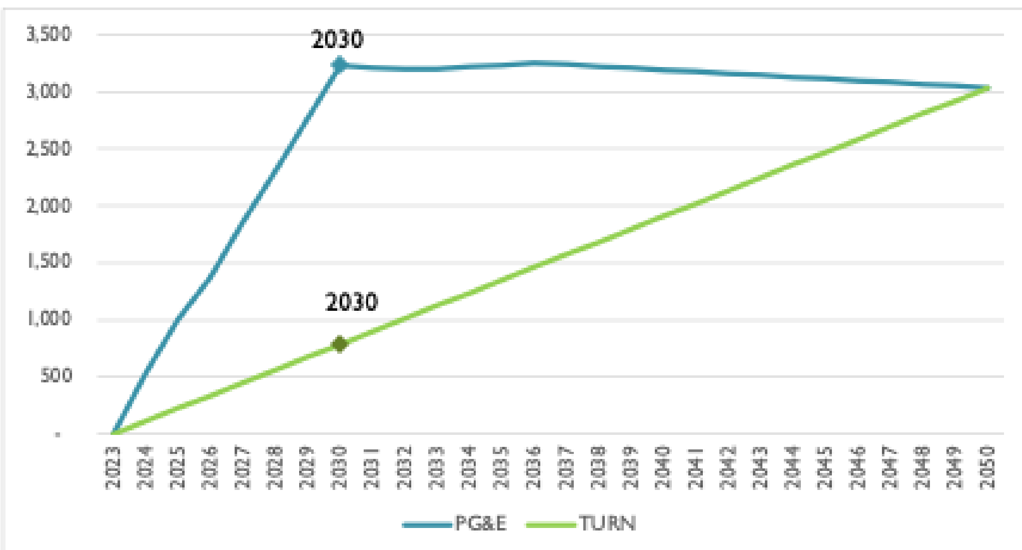
[64] Response to DR TURN-8, question 1, attachment 2.

[65] Response to DR TURN-5, question 1(d).

to dramatic and (until recently) unprecedented proposed spending levels to underground distribution infrastructure, in part based on this calculation.

TURN here offers an alternative approach based on the ICF data used by PG&E. Rather than utilizing results whereby all of climate change impacts' affect only the 2023-2030 time period, PG&E could incorporate a smoothed average estimate of climate change's annual impact based on ICF's results. To accomplish this, we calculate the average impact from 2023-2050 and then set this as the annual incremental amount by which climate change increases the baseline risk score. This approach would allow PG&E to incorporate a more gradual annual increase to the wildfire baseline risk score due to climate change while the Commission and parties explore the topic through a more robust process.

Figure 9. Alternative Estimate of Annual Impact of Climate Change on Baseline Wildfire Risk Score (Risk Units)[66]



5.5. PG&E Draws Incorrect Conclusions from Its Environmental and Social Justice Pilot Study

PG&E's RAMP presents an analysis that purports to show Disadvantage and Vulnerable Communities (DVCs) "receive a disproportionately large share of the benefit from wildfire

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[66] Response to DR TURN-8, question 1, attachment 2.

safety work."[67] The analysis allocates risk to DVC customers in each tranche, assuming risk in each tranche is uniform:

> % DVC customers (CS-freq weighted or CS-risk weighted) represent the percentage of tranche-level frequency or risk allocated to the DVC customers, assuming the circuit segment frequency or risk is allocated equally to each customer served by the circuit segment. This number is equivalent to the weighted average of % of DVC customers in a circuit segment, with the circuit segment frequency (or risk) as a weight.[68]

As stated, PG&E's analysis purports to show that on a risk-weighted basis DVC customers benefit disproportionately from wildfire mitigation work. For example, PG&E notes that in one tranche, based on this methodology, "the DVC customers, which make up 23% of the total customer population, get 29% of the risk reduction value from SH."[69]

There are numerous flaws in PG&E's analysis.

First, even if taken at face value, the analysis is not very compelling and does not actually show that DVC customers "disproportionately benefit." In total, DVC customers (according to PG&E's analysis) represent 29% of the population but receive 31% of the risk reduction "value".[70] This can hardly be viewed as "disproportional."

Further, PG&E's conclusions are not necessarily reasonable when analyzed more holistically. For example, PG&E's risk modeling results and DVC population analysis show that, while 97% of wildfire risk is contained in the HFRA, just 5% of the total DVC population resides there,[71] as shown in the table below. Using PG&E's logic, this means that <u>95%</u> of the DVC population does *not* benefit from programs like system hardening that occur in the HFRA. Further, since 16% of HFRA customers are DVC customers, <u>84%</u> of the beneficiaries of wildfire risk reduction programs (again using PG&E's logic) are non-DVC, even though non-DVC customers represent just 71% of the population (as stated above, 29% of the population are DVC customers).[72] One

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[67] PG&E 6/18/24 Workshop, slide 40.

[68] Response to DR TURN-10, question 3(b).

[69] PG&E 6/18/24 Workshop, slide 40.

[70] PG&E 6/18/24 Workshop, slide 40.

[71] PG&E Workpaper: EO-WLDFR-17_DVC analysis, tab "tranche and consequence."

[72] Id.

could therefore argue based on this data that ***non-***DVC customers disproportionately benefit from wildfire risk reduction in the HFRA.

Table 8. DVC Customers[73]

Total DVC Customers	1,608,416
DVC HFRA Customers	82,801
Total Percentage	*5%*

Total HFRA Customers	505,847
DVC HFRA Customers	82,801
Total Percentage	*16%*

Second, PG&E admits that its analysis allocates risk, and therefore implied risk reduction from wildfire risk reduction programs, uniformly across tranches, without regard to where projects will actually occur. HFRA tranches range from 477 primary and secondary miles to 14,231 miles, covering large geographic distances.[74] It therefore cannot be ascertained what "communities," much less specific customers, will actually benefit from these projects. Put another way, PG&E's methodology of allocating risk evenly across each tranche may have no relationship to how risk reduction accrues to DVCs or other types of communities, a fundamental flaw.[75]

Furthermore, contrary to PG&E's logic, TURN notes that locating an overhead hardening or undergrounding project to mitigate wildfire risk in a particular area does not necessarily benefit only the nearby community. Reducing the risk of wildfires, can provide at least some benefits to all of PG&E's customers, the state, and potentially out of state areas that would otherwise be subject to potentially toxic and harmful wildfire smoke.

Lastly, and perhaps most importantly, PG&E's analysis completely ignores affordability. Based on the lens by which PG&E presents its analysis, *any* amount of a regressive utility bill increase, as long as it reduces wildfire risk, would be "beneficial" to lower-income communities. This conclusion is contrary to any reasonable notion of fairness or equity. On this point alone,

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[73] *Id.*

[74] PG&E Workpaper: EO-WLDFR-17_DVC analysis, tab "tranche and consequence."

[75] Response to DR TURN-10, question 4(c).

PG&E's analysis is simply not useful for determining the extent to which DVCs benefit, or do not, from wildfire risk reduction programs.

TURN recognizes that PG&E's analysis was part of the Pilot Study ordered in D.22-12-027. However, recognizing that this type of analysis is new and in need of significant refinement, PG&E should refrain from stating dubious conclusions in its GRC, as it did at the June 18, 2024 workshop in this case, without a more solid analytic foundation.

This concludes TURN's informal comments.

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Appendix – Summary of Recommendations

- PG&E uses geography-agnostic data to calculate an interruption cost estimate of $3.17/CMI across its territory. This approach does not account for geographical differences in customer distribution and respective reliability impacts. TURN recommends a more nuanced four-tiered evaluation of $/CMI using tier-specific SAIDI values, resulting in an average electric reliability cost of $1.83/CMI.

- PG&E's hybrid approach for the Safety Attribute, applying California-specific adjustments to the DOT's nationwide Value of Statistical Life (VSL) to arrive at a VSL of $15.2 million, is contrary to DOT guidelines on the use of VSL and contrary to D.22-12-027. TURN recommends adhering to DOT guidelines by using the DOT's 2012 Value of Statistical Life (VSL) of $9.1 million, adjusted to $13.2 million for the year 2023.

- PG&E has not demonstrated that its extremely convex scaling function is reasonable. As required by D.24-05-064, PG&E's GRC submission should include alternative risk score and CBR results based on a risk neutral scaling function.

- PG&E's GRC filing should include workpapers that allow intervenors and the Commission to compare the CBRs of alternative mitigations assuming they are performed in the same risk areas. At minimum, upon request, PG&E should provide workpapers enabling such an apples-to-apples comparison within the customary 10 business-day data request cycle.

- PG&E should change its wildfire risk assumption of $1 million per structure destroyed to $723,000, the weighted average (by structures) from 2015-2022.

- The mitigation effectiveness of covered conductor should be based on recorded utility data. This may include data from Southern California Edison where applicable.

- PG&E's risk modeling should incorporate more realistic assumptions for PSPS customer minutes of outage, including an upper bound of around 272 million minutes per year.

- PG&E should assume PSPS mitigation effectiveness of 95% for destructive fires and 90% for large fires.

- In modeling climate change impacts, PG&E should incorporate less drastic annual increases for the rate case period in baseline wildfire risk based on its current modeling results while the Commission allows for more robust analysis of the issue in the S-MAP proceeding.

- PG&E conclusion that disadvantaged and vulnerable communities (DVCs) disproportionately benefit from wildfire risk reduction is poorly supported based on the current iteration of its DVC analysis. PG&E's conclusions about benefits to DVCs should be based on a more solid analytical foundation.