Safety Policy Division
Staff Evaluation Report
on
PG&E's 2020
Risk Assessment and Mitigation Phase
(RAMP) Application
(A.) 20-06-012

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Executive Summary

The Pacific Gas and Electric Company (PG&Es) Risk Assessment and Mitigation Phase (RAMP) Report provides an initial quantitative and probabilistic assessment of its top 12 safety risks, plans to mitigate these risks, and estimates of costs associated with the proposed mitigations. The mitigation plans and cost estimates are informed by Risk Spend Efficiency (RSE) calculations and alternative mitigations.

The Commission's Safety Policy Division (SPD) is required to review and evaluate PG&E's RAMP Report. Parties will be given an opportunity to file comments to PG&E's RAMP Report and SPD's evaluation report. The RAMP filing and comment process will form the basis of PG&E's assessment and proposed mitigations for its safety risks in the Test Year 2023 General Rate Case (TY 2023 GRC) filing.

This report summarizes the results of the SPD's staff evaluation of PG&E's 2020 RAMP Application, (A.)20-06-012. The 2020 PG&E RAMP application was filed in connection with PG&E's upcoming Test Year (TY) 2023 General Rate Case (GRC), covering proposed expenditures from years 2023 to 2026. This is the first PG&E RAMP application filed pursuant to the terms of the Settlement Agreement adopted through Decision (D.)18-12-015, in the Safety Model Assessment Phase (S-MAP) proceeding (A.15-05-002 et al).

The S-MAP Settlement Agreement specifies the use of a multi-attribute value function (MAVF) to evaluate and rank potential risk events. The MAVF captures the safety, reliability, and financial impact of these risk events. The MAVF is then used to calculate the risk scores for the risk events in PG&E's Enterprise Risk Register. The Settlement Agreement calls for using a minimum of 40 percent weight on the safety component of the MAVF. PG&E raised the safety weight to 50 percent, significantly impacting costs that PG&E proposed to mitigate safety risks such as serious injuries and fatalities.[1]

Since PG&E's last RAMP filed in 2017, several catastrophic wildfires of unprecedented scale in California's recent history ravaged large parts of the state. These wildfires had a drastic impact on the 2020 PG&E RAMP. In the 2017 RAMP, the wildfire risk was ranked fifth out of the 22 risks, just behind employee safety risks. In the 2020 RAMP, wildfires are the top risk with a score almost 26 times higher than the next highest risk score. Table 1 shows the risk names, the likelihood scores, the potential consequence scores, and the risk scores of the 12 twelve risks included in the 2020 RAMP:

[1] TURN identified a cost of $100 Million per fatality mitigated in its informal comments contained in Appendix 4 of this report.

TABLE 1: RAMP Risks Ordered by Multi-Attribute Risk Score

Risk Score	LoRE (Events/Yr)	CoRE	RAMP Risks
24,343	443	55	Ch 10: Wildfire
944	3,417	0.3	Ch 15: Third-Party Safety Incident
526	24,834	0.02	Ch 11: Failure of Electrical Overhead Assets
289	1.9	155	Ch 07: Loss of Containment on Gas Trans Pipeline
99	29,590	0.003	Ch 08: Loss of Containment on Gas Dist. Main or Service
97	8.2	12	Ch 14: Real Estate & Facilities Failure
94	185	0.5	Ch 17: Contractor Safety Incident
90	603	0.15	Ch 16: Employee Safety Incident
70	0.015	4,739	Ch 13: Large Uncontrolled Water Release
16.6	713	0.02	Ch 18: Motor Vehicle Safety Incident
13	5.6	2	Ch 09: Large Over-Pressure Event Downstream of Gas Measurement & Control Facility
7	10.2	0.6	Ch 12: Failure of Network Assets

PG&E's strategy for risk modeling, analysis and mitigation is oriented towards reducing the potential for catastrophic risk events and the consequences of those events. This risk-averse preference is captured through a non-linear scaling function that assigns more weight to higher potential consequences. The non-linear scaling function is then used in conjunction with the MAVF to calculate risk scores for PG&E's top safety risks.

The 2020 RAMP showed marked improvements in risk modeling rigor, data quality, and transparency over previous rate cases. Some of the improvements resulted from PG&E simply complying with the terms of S-MAP Settlement Agreement, while other improvements are the result of PG&E's own initiatives. Overall, PG&E's methodology in the 2020 RAMP Report conforms to the steps outlined in the Settlement Agreement. However, SPD found there is significant room for improvement in the areas of granularity and calculating RSEs for controls.

With respect to granularity, given the highly variable environments and conditions within PG&E's territory, risk analysis should be substantially more granular in many instances. Specifically, SPD staff finds that wildfire risk tranches should be much less expansive. Given the diverse environments and conditions covered by the over 99,000 overhead circuit miles, staff finds it unreasonable to assume a homogeneous risk profile across the tranches used for this RAMP Report and particularly for the three highest Multi-Attribute Risk Scored (MARS) wildfire HFTD[2] tranches. SPD staff also had this concern with the analysis of risks associated with large overpressure events downstream of gas measurement and control facilities, third party safety incidents, and others. These issues are discussed at length in each applicable risk chapter. Based on this analysis, staff concludes PG&E should continue to strive for a deeper level of granularity to better prioritize and evaluate mitigations with high risk reduction benefits.

An essential element of the S-MAP Settlement Agreement is the requirement for the utilities to provide RSE calculations for all mitigations in the RAMP filings. This is intended to enable the Commission and parties to compare the cost-effectiveness of a utility applicants' different mitigations in rate cases. Failing to calculate an RSE for controls leaves the Commission without a benchmarks against which proposed mitigations could be judged. PG&E only provided RSEs for a fraction of the controls described in this RAMP Report. SPD recommends PG&E and all IOUs provide RSE calculations for controls and mitigations or provide an explanation for why it is not able to provide such calculations.

PG&E's risk management approach continues to be reactive to catastrophic events. This was evident in the aftermath of the San Bruno explosion and is now evident in the rapid elevation of the wildfire risk from rank 5 in the 2017 RAMP to rank 1 in the 2020 RAMP. Those tragic events did more to uncover flaws in PG&E's operations, maintenance, and record-keeping than any of the risk assessment approaches employed by PG&E. If nothing else, this track record calls for continued improvements by PG&E and continued rigorous oversight by the Commission.

[2] See Decision 17-12-024 and more information here: https://www.cpuc.ca.gov/firethreatmaps/

Background and Introduction

Pursuant to the revised rate case plan schedule contained in D.20-01-002, PG&E filed its 2020 RAMP application on June 30, 2020. This RAMP application was filed in advance of PG&E's TY 2023 GRC application, which PG&E is expected to file by June 30, 2021. This RAMP application, covering years 2023 to 2026, has been given Commission proceeding number A.20-06-012.

Pursuant to the rate case plan in D.20-01-002 and as directed by the Scoping Ruling in A.20-06-012, SPD has been tasked to perform an evaluation of PG&E's RAMP application. This report summarizes the results of the evaluation.

This RAMP is the first PG&E RAMP that is subject to the terms of the Settlement Agreement adopted in the S-MAP Proceeding, A.15-05-002 et al.

The SPD evaluation team would like to acknowledge the contributions made by the various intervenor parties in the PG&E RAMP proceeding, including California Public Advocates (Cal Advocates), FEITA Bureau of Excellence (FEITA), the Mussey Grade Road Alliance (MGRA), and The Utility Reform Network (TURN) in written comments and during public workshops and video conferences held in connection with this proceeding.

Explanation of terms

RAMP Report – The main PG&E RAMP document in Attachment A of the RAMP application is referred to by PG&E as the "RAMP Report." Supporting workpapers are also included as part of the RAMP Report.

2020 RAMP – Since PG&E's 2017 RAMP filing, IOUs and the CPUC have referred to RAMP Applications by the calendar year in which the application is filed. PG&E refers to this Test-Year 2023 RAMP application (A.20-06-012) that was filed in calendar year 2020 as the "2020 RAMP."

TY 2023 GRC – The CPUC and IOUs 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 calendar year 2021 as the "TY 2023 GRC." The 2020 RAMP was filed in connection with the TY 2023 GRC, covering years 2023 to 2026.

Scope and Methodology of Evaluation

PG&E's RAMP Report contains 12 major risk chapters (Table 2), along with four chapters addressing other factors impacting PG&E's risk assessment (Table 3).

TABLE 2. Risk Chapters

RAMP Report Chapter	Risk
7	**Gas Operations**: Loss of Containment on Gas Transmission Pipeline
8	**Gas Operations**: Loss of Containment on Gas Distribution Main or Service
9	**Gas Operations**: Large Overpressure Event Downstream of Measurement & Control Facility
10	**Electric Operations**: Wildfire
11	**Electric Operations**: Failure of Distribution Overhead Assets
12	**Electric Operations**: Failure of Electric Distribution Network Assets
13	**Power Generation**: Large Uncontrolled Water Release
14	**Corporate Real Estate**: Real Estate & Facilities Failure
15	**Enterprise Health and Safety**: Third Party Safety Incident
16	**Enterprise Health and Safety**: Employee Safety Incident
17	**Enterprise Health and Safety**: Contractor Safety Incident
18	**Enterprise Health and Safety**: Motor Vehicle Safety Incident

TABLE 3. Chapters on Other Risk Factors

RAMP Report Chapter	Other Factors
6	**Pandemic Impact Assessment**
19	**Other Safety Risks**
20	**Cross-Cutting Factors**
21	**Steady State Operations**

Following the order of the RAMP Report, this evaluation first examines the soundness and adequacy of the overall risk assessment and evaluation approach and whether that approach complies with the MAVF process specified in the S-MAP Settlement Agreement. Each risk chapter is then evaluated in detail. One aspect of the evaluation revolves around the analysis of Risk Spend Efficiency (RSE) scores. RSE of a mitigation program is defined as the amount of risk reduction divided by the cost of the mitigation program. The verification of mitigation cost estimates is beyond the scope of this evaluation. To the extent that there are uncertainties and potential errors in PG&E's mitigation cost estimates, those uncertainties and potential errors would carry through to the RSE calculations, leading to potential errors in the mitigation decisions. The cost estimates should be substantiated in the TY 2023 GRC.

The Scoping Memo in the PG&E RAMP proceeding enumerates the following questions to be considered in the evaluation of PG&E's RAMP Report:

1. Whether PG&E's RAMP Report and analysis is complete and in compliance with D.14-12-025, D.16-08-018 and the S-MAP Settlement adopted in D.18-12-014.

2. Whether PG&E acted reasonably in the instances where it exercised discretion in implementing the requirements of the S-MAP settlement.

3. Whether there are gaps in identifying risks and considering mitigation options:
   a. Whether key safety risks have been properly identified, assessed, and analyzed.
   b. Whether risk analysis is adequately supported.
   c. Whether effective mitigation programs have been developed and defined with sufficient granularity.
   d. Whether cost effectiveness of mitigations has been reasonably assessed and analyzed.
   e. Whether alternatives have been fully considered and adequately discussed.
   f. Whether safety and other risks associated with Public Safety Power Shutoffs (PSPS) have been fully and adequately considered.

4. Whether the MAVF and RSE calculations are reasonable and consistent with the S-MAP settlement.

5. Whether PG&E's analysis is transparent and allows for independent validation of its results.

Key Differences between 2020 RAMP and 2017 RAMP

PG&E's 2020 RAMP has incorporated improvements over risk evaluation methodologies presented in the prior RAMP and in previous rate cases. Some improvements are attributable to implementation of the S-MAP Settlement Agreement, while other improvements are the result of PG&E's own initiatives.

Improvements are evident in the greater use of data derived from PG&E's own historical frequency and consequence experience, and reduced reliance on less applicable industry-wide data or the judgements of subject matter experts. There are also improvements in modeling rigor through the much wider use of probabilistic functions to describe the stochastic behavior of risk drivers and event consequences in the risk bow tie. Refinements were also made in the reclassification of some risk drivers as cross-cutting factors affecting multiple risks.

There are also many similarities between the current 2020 RAMP and the 2017 RAMP. Prior to the adoption of the MAVF framework in the Settlement Agreement in D.18-12-014, PG&E was already using a version of the multi-attribute concept to calculate risk scores in their 2017 RAMP. In the 2017 RAMP, PG&E referred to the risk scores obtained by this method as multi-attribute risk scores (MARS). In the 2020 RAMP, PG&E continues the use of event-based bow ties that was first used in the 2017 RAMP to perform risk analysis using a very similar MAVF, with only minor difference in the attributes and the corresponding attribute weights.

Although not explicitly stated, risks are conceptually treated the same way in both RAMPs. Risks are represented in the risk bow tie, including the risk drivers, the sub-drivers, the trigger event frequencies (or probability functions), the triggering event, the consequence scenarios (and their probability distributions), and the cross-cutting factors.

One key difference between the 2017 RAMP and the 2020 RAMP is that PG&E is no longer presenting the worst-case probable events (also called P95 or "tail average") risk scores evaluated at the 95th percentile. These P95 risk scores were meant to capture PG&E's aversion to low-frequency, high consequence events. In the 2017 RAMP, PG&E presented the risk scores evaluated at both the expected (or 50th percentile) value and the 95th percentile.

In the current RAMP, PG&E dispenses with the P95 concept and instead uses a scaling function to transform the values of the various attributes measured in natural measurement units into scaled dimensionless units. As described in Chapter 3 of Attachment A of the RAMP Report, PG&E uses a non-linear scaling function, as is permitted under Row 6 of the Settlement Agreement, to assign more weight to the high end of the range of the natural measurement units in order to capture PG&E's aversion to high consequence outcomes. In the current RAMP, only one set of risk scores is produced at the expected value, but with the scaling function applied to capture PG&E's risk aversion to high consequence outcomes.

Another change in the current RAMP is that PG&E has migrated from using the commercial simulation software @Risk to instead relying on its own simulation routines developed in-house using the Python computer language. PG&E characterizes this migration as an improvement over commercial software as it has given PG&E greater modeling flexibility.

PG&E's Risk Selection Process

The Settlement Agreement in Step 1B, Row 8 specifies the process the utilities must use to select risks to be concluded in the RAMP. The process begins with the enterprise risk register, which PG&E refers to as the Corporate Risk Register (CRR). It currently contains 33 event-based enterprise (or corporate) risk events. The RAMP Report does not describe how the 33 risk-events were derived.

The Settlement Agreement in Step 2A, Row 9 then describes the process whereby the initial enterprise risks in the risk register are evaluated for safety impacts on and given an initial safety-only score. The resultant safety-only scores are then sorted, with the top 40 percent to be included in the RAMP.

PG&E applied this step to the 33 risks in the CRR. Of these 33 CRR risks, 26 had a safety score greater than zero. These 26 risks were then sorted, and the top 40 percent cutoff produced the top 11 safety risks. PG&E also applied an additional mechanism: it included any residual risks that were within 20 percent of the lowest safety score in the aforementioned risks. This mechanism resulted in one additional risk, leading to a total of 12 safety risks to be included in the 2020 RAMP.

These 12 RAMP risks were then fully evaluated using PG&E's full Multi-Attribute Value Function, which considered reliability and financial impacts in addition to safety. The risk evaluation then proceeded through the additional steps specified in the Settlement Agreement.

The process PG&E utilized to select the enterprise-level safety risks to be included in the 2020 RAMP Report conformed to the requirements laid out in the Settlement Agreement. PG&E's use of an additional mechanism to include marginal risks within 20 percent of the 40 percent cutoff mark helped to ensure a more conservative and inclusive selection of safety risks.

Compliance of PG&E 2020 RAMP with S-MAP Settlement Agreement

This section evaluates PG&E's compliance with the terms of the S-MAP Settlement Agreement, which consists of the following steps (see pg. 33 of Decision D.18-12-014):

- Step 1 A – Building a Multi-Attribute Value Function (Rows 1 – 7).
- Step 1 B – Identifying Risks for the Enterprise Risk Register (Row 8).
- Step 2A – Risk Assessment and Risk Ranking in Preparation for RAMP (Rows 9 – 11).
- Step 2B – Selecting Enterprise Risk for RAMP (Row 12).
- Step 3 – Mitigation Analysis for Risks in RAMP (Rows 13 – 25).

In addition to the above steps, the Settlement Agreement also lists requirements of Global Items in Rows 26 to 33.

Under Row 30 of the Settlement Agreement, intervenors may request sensitivity analyses of the utility applicant's models via the discovery process. Four intervenor parties, including Cal Advocates, FEITA, MGRA, and TURN, as well as SPD staff requested that PG&E rerun the simulations on some specific risks using different assumptions and different parameters from those used by PG&E in the RAMP Report. PG&E re-ran the models on those risks using the assumptions and parameters as specified by the intervenor parties and SPD staff. At the request of SPD staff, the four intervenor parties also prepared informal comments[3] on the results produced from their individual scenario runs to give detailed interpretations to the results.

This portion of the evaluation draws from insights contained in intervenors' informal comments. The intervenors' informal comments are included for reference as Appendices 1 to 4 at the end of this report.

Overall, PG&E's methodology in the 2020 RAMP Report conforms to the steps outlined in the Settlement Agreement. However, SPD found there is room for improvement in the areas of granularity and calculating RSEs for controls.

Tranches lacking in homogeneous risk characteristics

The Settlement Agreement defines a tranche as "a logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment." Row 14 of the Settlement Agreement specifies that the tranche selections would be sufficiently granular so that "each element (i.e., asset or system) contained in the identified tranche would be considered to have homogeneous risk profiles (i.e., considered to have the same LoRE and CoRE)."

[3] The four intervenor parties circulated their informal comments through e-mails to the service list in the PG&E 2020 RAMP proceeding on November 2, 2020.

Given the diverse regions within PG&E's territory, risk analysis should be substantially more granular in many instances. As examples, SPD staff found that wildfire risk tranches were too expansive. PG&E's 30,000 circuit miles cover highly variable environments and conditions that are not adequately reflected in the tranches used for this RAMP Report. Staff also had this concern for the analysis of risks associated with large overpressure events downstream of gas measurement and control facilities. For example, the risk from larger diameter and/or higher-pressure transmission lines is greater than for smaller/lower pressure transmission lines, which could provide additional tranche groupings. These issues are discussed in more detail in subsequent sections. Suffice it to say, PG&E should continue to strive for a deeper level of granularity. Ideally, improvements on this analysis can be made when they submit their wildfire mitigation plan and prior to filing their TY 2023 GRC. SPD staff make this recommendation understanding that there are constraints with data availability and possible increases in risk modeling uncertainty as large tranches are divided into finer tranches with fewer data points per tranche.

RSE Calculations

One essential element of the S-MAP Settlement Agreement is the requirement for the utilities to provide RSE calculations for all mitigations in the RAMP filings. Specifically, Row 26 in the S-MAP Settlement Agreement requires the utility applicant to "provide a ranking of all RAMP mitigations by RSE." This requirement was intended to enable the Commission, intervenors, and the public to compare the cost-effectiveness of a utility applicants' different mitigations in rate cases. Being able to compare mitigations based on their cost-effectiveness was a primary impetus behind the Joint Intervenors' Approach (JIA) proposed in the first S-MAP, which eventually led to the S-MAP Settlement Agreement.

RSE calculations and ranking of all RAMP mitigations by RSEs are fundamental to the MAVF risk evaluation approach adopted in the S-MAP Settlement Agreement.

Beginning with its 2017 RAMP, PG&E drew a distinction between existing mitigations and proposed mitigations by referring to existing mitigations as "controls." PG&E clarified that controls are primarily existing and compliance-based mitigations.[4] While there may be valid reasons for distinguishing existing compliance-based mitigations (i.e. controls) from new and proposed mitigations, these controls should also be evaluated for cost effectiveness, as those RSEs provide benchmarks against which proposed mitigations could be judged. Failing to calculate an RSE for controls undermines the intent of Row 26 of the Settlement Agreement. SPD recommends PG&E and all IOUs provide RSE calculations for controls and mitigations or provide an explanation for why it is not able to provide such calculations.
PG&E cited "reduced preparation time, and the need to advance urgent wildfire safety work" as the reasons for its failure in the current RAMP to evaluate risk reduction

[4] PG&E RAMP Report, pg.1-15

achieved through existing controls and to provide the corresponding RSEs.[5] For this RAMP, PG&E only provided RSEs on two control programs: Leak Management (in Ch. 8) and Enhanced Inspection Program (in Ch. 11). At a meeting between SPD staff and PG&E representatives on Nov. 3, 2020, a PG&E representative stated that PG&E will provide RSE calculations for all controls in its upcoming TY2023 GRC application.

Other observations

1. **Lack of consideration for uncertainties in the estimates.** PG&E's risk modeling approach has gained substantial mathematical and probabilistic rigor over the last few rate case cycles, but it still presents results as point estimates evaluated at their expected values. Although presenting results at the expected values is partially a feature of the Settlement Agreement, nothing in the Settlement Agreement prevents PG&E from incorporating uncertainties when presenting the risk evaluation results. There would be value to stakeholders in rate case proceedings if PG&E provided not only the risk scores and RSEs but also confidence intervals associated with the risk scores and RSEs. Although mitigation decisions should be based largely on RSE rankings, those decisions should also consider the uncertainty of each estimate. For example, it is possible that a mitigation option with a high RSE may also have a very wide confidence interval, while an alternative mitigation with a slightly lower RSE may have a much narrower confidence interval. In such a scenario the preference for the mitigation option with a higher RSE may be less clear cut and some judgement may be needed to arbitrate between the two mitigation options.

2. **Lack of justification to apply a 50-50 weighting between PG&E data and industry-wide data.** PG&E provides no justification for selected weights combining PG&E's own data with industry-wide data. On the gas transmission risks, for example, PG&E assigned 50 percent/50 percent weights to combine PG&E's frequency data with industry-wide data. SPD staff recommend that PG&E should apply techniques based on credibility theory[6] to arrive at appropriate weightings for different risk data sets to maximize the applicability of the resultant data.

3. **The non-linear scaling function PG&E used in this RAMP to apply more weight to high consequence events can result in very costly risk mitigation decisions.** PG&E stated in Chapter 3 of the 2020 RAMP Report its risk management philosophy is focused on reducing catastrophic risk events, also known as low frequency, high consequence events.[7] To operationalize this risk aversion, PG&E uses a non-linear

[5] PG&E RAMP Report, pg.1-6.

[6] Credibility theory is a branch of probability and statistics theory predominantly used by insurance companies to combine a company's own limited loss experience with industry-wide loss data to improve the confidence of the combined data applicable to the insurance company. The same techniques can be readily adapted to applications outside of the insurance field. More information can be found here: Kaas, Rob & Goovaerts, Marc & Dhaene, Jan & Denuit, Michel. (2002). Credibility theory. 10.1007/0-306-47603-7_7.

[7] PG&E 2020 RAMP Report, pg. 3-2, Section B.

scaling function. PG&E cited the "greater potential uncertainty surrounding catastrophic events, and their potential to disrupt communities and operations" as justifications for PG&E's preference to be risk-averse.[8] Non-linear scaling functions are permitted pursuant to Row 6 of the Settlement Agreement.

TURN's informal comments (Appendix 4), in arguing for the use of a linear scaling function, use a counterexample[9] to demonstrate what TURN characterizes as an "irrational" mitigation decision that would result from strict application of PG&E's non-linear, risk-averse scaling function. In the hypothetical counterexample, TURN illustrates that PG&E would prefer to reduce the expected fatalities from 11 to 10 for a high consequence event (for a net avoidance of one fatality) over the reduction of one fatality for ten low-fatality-count events (for a total avoidance of ten fatalities). In direct economic terms, the mitigation decision presented in TURN's counterexample could be viewed as irrational. However, this view does not take into account the secondary societal costs as well as the hugely negative psychological impacts and disproportional disruptions on affected communities caused by catastrophic events. When those secondary societal costs and negative societal psychological impacts are taken into consideration, the conclusion of an irrational mitigation decision is no longer so clear cut.

While not using the term "irrational" PG&E concurred with TURN's assessment of their model saying, "[g]iven a choice between two mitigations that theoretically reduce the same expected amount of loss, one of which is targeted at catastrophic (low frequency, high consequence) risk events and another that is targeted at routine (high frequency, low consequence) risk events, our preference is to select the mitigation that targets the catastrophic events because of the uncertainty of their frequency and consequence.[10]" They go on to say that the consequences of catastrophic events are more destructive, disruptive, and disproportionately affect impacted communities.

Under the backdrop of a general rate case, TURN asks a legitimate question as to whether a highly risk-averse risk management strategy may be predominantly benefitting the utility shareholders' financial interests at the expense of ratepayers'. In the first S-MAP decision, D.16-089-018, Ordering Paragraph 6 directed PG&E and the other three large energy IOUs to "*remove shareholders' financial interests from consideration in their risk models and decision frameworks used to support rate case expenditure proposals …*" The Commission should examine whether PG&E's non-linear, risk-averse scaling function may be conflicting with this Commission directive. While simpler, the use of a linear function is not straightforward. Given that, in the

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[8] PG&E 2020 RAMP Report, pg. 3-48, Section B.

[9] Counterexample is found in Section 3.1 on page 8 of TURN's informal comments.

[10] PG&E 2020 RAMP Report, pg. 3-2 and pg. 3-3, Section B.

past few years, catastrophic events have resulted in substantially more public serious injuries and fatalities, more property destruction, more community devastation than more frequent, low impact incidents, this issue warrants further discussion and evaluation.

4. **The high safety weight of 0.5 relative to the financial weight of 0.25 in the MAVF results in an implied value of statistical life (VSL) of $100 Million.** The VSL can be viewed in the GRC context as monetary costs ratepayers would be asked to pay for a reduction in mortality risk. Both MGRA and TURN made this observation in their informal comments. It should be noted this implied VSL amount is approximately ten times larger than the VSL estimates published by several U.S. federal government agencies.

5. **PG&E's use of empirical and lognormal distributions to model the wildfire risk may not be appropriate.** In both its initial protest and informal comments, MGRA provided reference sources to support the assertion that wildfire frequency and severity behavior follow the power law distribution. Since PG&E does not use the power law distribution to model the wildfire risk in the 2020 RAMP, PG&E is underestimating the wildfire risk, assuming the validity of the reference resources provide by MGRA. One feature of the power law distribution is that the mean based on historical data would always underestimate the true mean. PG&E's use of historical data to estimate the mean would therefore underestimate the wildfire risk. PG&E should address this concern by revisiting its wildfire modeling approach to determine whether it should replace its current model with power law distributions.

Safety Culture and Compensation

In Chapter 5 of its RAMP, PG&E outlines several programs designed to strengthen and improve their safety culture. These include taking officers and directors to the field to interact with and observe hourly employees, requiring that safety be part of hiring criteria in all jobs, requiring that every employee have a safety-related performance objective in their annual plan, providing training on safety leadership, and surveying attitudes and beliefs about safety within the company.

SPD and Wildfire Safety Division (WSD) continue to monitor PG&E's safety culture and performance. At least three ongoing activities are currently underway to evaluate if PG&E is improving and evolving its safety culture and making progress on public, contractor, and employee safety outcomes include:

1. Safety Certification and Safety Culture assessment conducted by the Wildfire Safety Division pursuant to public utilities code Sec. 8389 (c).

2. Implementing a reorganization following their bankruptcy (D.20-05-053), which includes several safety related reforms, regionalization, and a new enhanced oversight and enforcement process carried out by the Commission.

3. Ongoing safety culture review pursuant to the Order Instituting an Investigation on safety culture (I.15-08-019). PG&E prepares quarterly reports that summarize their implementation of recommendations from NorthStar, the third-party consultant hired to investigate PG&E's safety culture. Oversight by the Commission and NorthStar is ongoing in the aftermath of the bankruptcy to ensure that PG&E continues to progress its Enterprise Safety Management System (ESMS) and evaluates the sustainability of the safety culture initiatives implemented to date.

PG&E has tied its governance and some compensation models to safety outcomes. Their plans appear to be consistent with direction it has received from the Commission and industry best practices. The Commission, through enforcement of decisions and ongoing investigation will continue to monitor PG&E's progress in this area.

EVALUATION OF INDIVIDUAL RISK CHAPTERS

Chapter 6: Pandemic

Risk Description

PG&E conducted a rudimentary, qualitative assessment of the risks associated with the COVID-19 Pandemic based on conversations with Risk Management Teams within PG&E and their Emergency Operations Center (EOC). PG&E described the steps they took to protect their workforce, and based on limited data and anecdotal information, PG&E speculated about impacts to risk drivers stemming from the public's and their employees' experiences during the pandemic. With the limited information available, three general risk themes emerged:

a. New working conditions presenting human performance concerns;
b. Changes in the public's contact with PG&E assets; and
c. Concerns over prolonged delays in non-essential work.

PG&E acknowledges that this is not an exhaustive list of potential COVID-19 Pandemic related risks, stating that "many issues that may arise as the pandemic continues and as we begin to transition back to a new normal post pandemic environment at work, schools, home, transportation, shopping, etc." With these general concerns in mind, PG&E surveyed their Risk Management Teams about how COVID-19 may impact the risks for which they are responsible.

Observations

First, PG&E did not explain or describe any efforts to reduce the effects of the pandemic on human performance. Presumably, they are using their Employee Assistant Program, Peer Volunteer Program, and Employee Health Screenings and Health Coaching controls to help mitigate the impacts of the additional challenges posed by the pandemic, but how they are doing this was not mentioned.

Second, PG&E did not provide details about the potential impacts associated with deferral of nonessential maintenance. They acknowledged "the impact of a prolonged delay in non-essential work is unknown at this time," but then went on to say that subject matter experts expressed concern that "the likelihood of risk events could increase if delays in non-essential work were to continue for the foreseeable future." They also stated that their subject matter experts "expressed concern that a prolonged public health response to the pandemic may impact the supply chain for critical parts and equipment by requiring suppliers to remain closed." More detail about the specific concerns expressed from the interviews would improve SPD's ability to evaluate these potential risks.

Finally, a developing risk that could occur in the upcoming year could be a significant number of gas and electrical shutoffs. To protect customers who have experienced disruptions in employment or otherwise lost income due to the pandemic, the Commission passed [Resolution M-4824](), extending the emergency customer protections from D.19-07-015 and D.19-08-025 through April 16, 2021, with an option to extend. According to Energy Division,[11] as of the end of September 2020, approximately 439,000 residential customers across all IOUs had over $500 in arrearages, a 166 percent growth compared to September 2019 (over 274,000 additional customers). If these customers do not enroll in payment or arrearage management plans and their outstanding balances continue to accrue, they could be at risk of disconnection when the disconnection moratorium is lifted. Without relief these customers could be exposed to risks associated with failure of medical equipment, high temperatures, a lack of refrigeration and the associated health and safety risks.

Bow tie

PG&E did not generate a bow tie analysis for the risks and consequences of the pandemic. With scant data to rely on and given the lack of recent precedent, PG&E provided a brief qualitative analysis of the risks associated with COVID-19.

As discussed below, PG&E provided some speculation as to how risk drivers considered in other chapters could be impacted by disruptions in employees' lives and broader, societal changes modifying behavior patterns amongst large segments of the public.

Exposure

Of the three risk themes identified by PG&E, the pandemic is expected to impact two risks and have a more ambiguous effect on one risk. PG&E expressed concern about risk drivers associated with human performance and the prolonged deferral of non-essential work. For third-party contacts with PG&E infrastructure, the analysis indicates there could be a reduced risk of accidents resulting from reduced vehicle traffic.

For human performance, PG&E indicated that the various stresses placed on employees due to the pandemic could increase safety risks. These stressors include increased childcare responsibilities, closeness to individuals who are have become sick with or have died from COVID-19, stress induced by social isolation, and other impacts. Because this situation is unique in recent history, PG&E is not able to quantify the impact of these stressors, but they are concerned that they could lead to a marginal increase in accidents or errors.

One possible risk reduction benefit of the pandemic is a decrease in third-party contact with PG&E electric and gas system assets due to extended shelter-in-place and social distancing orders. Third-party contact with PG&E assets is a driver in a number of PG&E's safety risk models.

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[11] October 16, 2020 Memo to Commissioner on "COVID Related Energy and Gas statistics."

Finally, PG&E indicated concerns regarding the impact of prolonged deferral of non-essential work, stating that “the efficacy of some discretionary risk control programs could be less than what is currently included in models due to lack of skilled and qualified workforce availability for deployment in the field because of shelter-in-place and social distancing orders, supply chain disruptions or the inability of partnering organizations to provide support services that PG&E relies upon for risk control.” However, on pages six to seven they state, “PG&E’s Electric Operations will continue performing electric work consistent with the Governor’s priorities for essential services and for the safety of our customers and communities…” They then go on to list all the activities they are still undertaking in order to safeguard PG&E infrastructure and the public. As a result, aside from unspecified concerns from their internal discussions with subject matter experts, it is not clear what the risk exposure of the aforementioned “prolonged deferral of non-essential work” would be.

Summary of Findings

Given the unprecedented nature of the COVID-19 pandemic, PG&E’s analysis is understandably limited. PG&E indicated that they would collect data and continue to improve their understanding of impacts of the pandemic to model risks and potential mitigations.

While this is a reasonable first analysis of the impacts, the effects of the pandemic are likely to continue at least through the spring and summer of 2021. In the coming months, as PG&E prepares its general rate case, they should continue to evaluate the extent of the risk exposure and ensure risks are mitigated to the maximum extent possible.

Recommended solutions to address findings and deficiencies

PG&E should further evaluate the identified risks on human performance identified in their application and explain what efforts they are undertaking to help their employees and contractors endure the societal impacts of the pandemic. For example, if PG&E has increased efforts and outreach through their Employee Assistance Program, Peer Volunteer Program, and Employee Health Screening and Coaching to assist their workforce in coping with the impacts, they should explain these efforts as risk mitigations for human performance.

PG&E should provide more specific information and examples of possible impacts associated with prolonged deferral of nonessential work and possible impacts on the supply chain of necessary materials. The RAMP application does not include specific examples of either making it difficult to evaluate the gravity or extent of the identified risk.

RAMP Risk (Ch. 7): Loss of Containment on Gas Transmission Pipeline

Risk Description

This RAMP chapter examines the risk that natural gas transmission pipelines will lose containment, potentially resulting in human injury, loss of service, and financial loss. It does not include the risk of large overpressure events downstream of measurement and control stations, which is analyzed separately in Chapter 9 of the PG&E TY2023 RAMP Report.

Bow tie

The bow tie presents risk drivers and their frequencies on the left of the diagram, with risk consequences and associated frequencies on the right. The score of 289 is fourth highest of the 12 RAMP risks and considerably lower than the scores for the top three risks: Wildfire (24,343), Third-Party Safety (944) and Failure of Distribution Overhead Assets (526).

Observations

Staff finds the bow tie presentation conforms with the Settlement Agreement, although some parties have objected to PG&E's use of risk event frequency rather than risk event likelihood as the value for LoRE. Staff believes the PG&E use of frequency is a practical way of accounting for risk when more than one event is expected per year, such that the likelihood is greater than one.

Exposure

Risk exposure is presented as the 6,682 total miles of gas transmission pipeline in the PG&E system.

Observations

Transmission lines are the backbone of supply to PG&E's operations, and generally operate at high pressure with large pipe diameters over long distances. Using miles of pipeline is consistent with the examples provided in the definition of "exposure" in the Settlement Agreement.

Tranches

PG&E created four tranches based on operating pressure conditions and affected population. When operating pressure is 20 percent or less of the pipe material SMYS (Specified Maximum Yield Strength), studies have shown that a leak is more likely than a rupture. The consequences of a rupture are generally more severe than of a leak. PG&E uses an Impacted Occupancy Count (IOC) of 10 persons within the potential impact radius as threshold for severity of impacts on people in the area affected.

Observations
The two high-SMYS tranches account for most of the exposure, 75 percent of the 6,822 miles, and 80 percent of the total risk score. These tranche choices are logical. However, additional categories which affect the likelihood of a risk event such as age of the pipe materials and geographic locations including earthquake fault zones, agricultural land subject to tilling, or urban settings likely to experience excavations could improve the analysis and result in more targeted mitigation.

Risk Drivers
The nine primary risk drivers are chosen from the list of pipeline integrity threats established in the American Society of Mechanical Engineers (ASME) Standard B31.8S such as Third-Party Damage, External and Internal Corrosion, Construction Threats, and Incorrect Operation. PG&E added cross-cutting threats such as seismic and physical attack.

Observations
Staff finds the identified risk drivers are appropriate factors that contribute to the likelihood of failure, as defined in the Settlement Agreement.

Risk Driver Frequencies
According to the RAMP Report, the event frequency data is a combination of PG&E's incident history and Federal Pipeline and Hazardous Materials Safety Administration (PHMSA) national data for the same period. The PHMSA data was used to estimate risk driver frequencies that are not included in the PG&E Transmission Integrity Management Program (TIMP) risk model which focuses on safety, rather than reliability or financial outcomes.

Seismic events are a cross-cutting driver. Seismic frequency was generated from PG&E's Seismic Earthquake Risk Assessment (SERA) model (Chapter 20). The frequency of seismic events is 0.20, or once in five years.

Observations
Each driver is assigned a frequency in terms of events per year based on the likelihood of risk event per unit of exposure (LoRE,) multiplied by the exposure (pipe miles) to produce the event frequency for the whole gas transmission system. The baseline year is set to 2023, so the historical data should be adjusted to account for expected mitigations from 2020-2022. Staff could not confirm from the RAMP Report or the Workpapers that this adjustment was made for Chapter 7. However, staff does not expect that the total driver frequency of 1.9 events per year would change significantly during the 2020-2022 period, so the risk score would not significantly change from such an adjustment.

The small number of events, 1.9 events per year for the entire PG&E gas transmission system, is consistent with staff expectations that events leading to loss of containment on transmission pipelines are rare. The greatest driver frequency is third-party damage at 0.33 events per year or one in three years. This frequency is consonant with recent third-party ruptures in the San Joaquin Valley. In the last 10 years, excavation equipment operators have dug into PG&E transmission pipelines on two occasions[12] resulting in ruptures with fire, fatality, and serious injuries. The dig-in at the Fresno County Sheriff's facility next to Highway 99 produced a tower of fire that shut down the highway and damaged the railroad line. The excavators had not followed the "Call-Before-You-Dig" procedures before the work.

Staff finds the risk driver frequencies are reasonable.

Outcome Frequencies

Loss of Containment outcomes are either ruptures or leaks. The highest frequency outcome is leaks, at 49 percent of the total outcome occurrences. Cross-cutting (c-c) factors add another 2.4 percent of leak outcomes for a leak total of 51 percent. Ruptures account for 39 percent while the Seismic c-c-factor adds another 9.6 percent for a total rupture outcome of 49 percent.

Observations

Rupture outcomes occur almost as often as leaks, which makes sense considering that many transmission pipelines operate at high pressures relative to yield strength as noted in the tranche section. Staff finds that the outcome frequencies are reasonable.

Cross-cutting factors

PG&E included four cross-cutting factors as risk drivers: seismic, physical attack, record keeping and information management (RIM), and skilled and qualified workforce (SQWF). The seismic factor accounted for 11 percent of the driver events, while the other factors had small impacts. Staff finds the choice of cross-cutting factors reasonable.

Consequences

This chapter's consequences were based on incident outcome data that included both PG&E and PHMSA incidents. Consequence scores incorporate safety, reliability, and financial risk attributes. The scores are dimensionless numbers that are intended to allow comparisons between one risk and another, and to support measurement of risk level changes.

Table7-4 of the RAMP Report presents the consequences in their natural units, such as equivalent fatalities for the safety risk, dollars for financial risk, etc. The safety

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[12] April 17, 2015 in Fresno, November 13, 2015 in Bakersfield.

consequence for all risk outcomes is 1.0 equivalent fatalities (EF) per year, which corresponds to a safety attribute score of 128. 99 percent of this safety score is due to rupture outcomes.

Observations

In Chapter 8, a similar safety outcome in natural units of 1.176 Equivalent Fatalities (EF) produced a lower safety attribute risk score of 72. The risk score is the product of LoRE times CoRE. The CoRE in Chapter 8 is lower because of the MAVF process, which incorporates the low frequency of outcomes that produce a safety result.

The reliability attribute score of 154 is higher than the safety score of 128. That result seems reasonable since loss of containment on a transmission pipeline can interfere with delivery of gas to large numbers of customers.

The safety consequences conform with Staff expectations.

Controls and Mitigations

Controls

Most of the controls are based on the gas safety rules in CPUC GO-112F, which incorporates the PHMSA federal code 49 CFR Part 192. All the controls were in effect in the 2017 RAMP Report for the TY 2020 GRC and are expected to continue. Such controls include leak survey, corrosion control, and public awareness.

Mitigations

Six current programs are proposed to continue for the 2023-2026 period, although two will be combined into one program (M5 Shallow Pipe, M6 Exposed Pipe). No new mitigations are proposed.

Risk Spend Efficiency

For each mitigation, PG&E presents an RSE figure. RSE is the ratio of risk score reduction divided by the cost to achieve the reduction (multiplied by a scaling factor of 1000 for readability). The RSE values are expected to guide decision makers in the GRC on whether to approve ratepayer funding for the proposed mitigations. Some mitigations may offer more cost-effective risk reduction than others.

As with nearly all the controls in this RAMP Report, none of the Chapter 7 control programs were evaluated for RSE. Chapter 8's evaluation of risk for gas distribution systems provides an RSE for one control program, leak management (C4), which is useful for comparison to the RSE's presented here. The proposed mitigations have considerably lower risk spend efficiencies than the example control program, as shown in Table 7-1.

TABLE 7-1. Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026

Program	Expense ($000s)	Capital ($000s)	Risk Score Reduction	Risk Spend Efficiency
C4 Leak Management (control)	291,957	-	153.6	0.716
M1 In Line Inspection Upgrades		628,234	44	0.100
M2 Strength Testing	378,019		37.9	0.140
M3 Vintage Pipe Replacement		146,890	4.2	0.040
M4 Valve Automation		140,167	8.7	0.080
M5 Shallow Pipe		30,809	0.5	0.020
M6 Exposed Pipe		43,660	0.6	0.020

The most expensive mitigation, M1 in line inspection (ILI) upgrades, has an RSE of 0.100 at a cost of $628 million over four years. This mitigation is seven times less effective than just one of the existing control programs, leak management. The proposed cost is in addition to the $495 million already forecasted for ILI upgrades in 2020-2022. The risk score reduction for ILI upgrades is 44, which would improve the baseline score of 289 to 245, or 15 percent. In the best-case scenario, if all the improvement went to safety rather than reliability or financial risk, a 15 percent reduction of the one equivalent fatality expected per year would save 0.15 EFs per year or 1 full EF every 7 years.

The most effective mitigation is M2 strength testing with an RSE of 0.14 and a cost of $378 million. Yet this proposal is five times less effective than the C4 leak management control.

While these mitigations were all previously approved in rate cases, examination of the risk spend efficiency may provide opportunity for cost reductions in some programs to allow spending on other more effective mitigations.

Alternatives Analysis

PG&E presents two alternative mitigations, considered in combination with the other proposed mitigations. The alternative analysis included estimated risk reduction and RSE.

The first alternative would mitigate the risk to transmission pipe from rising sea levels caused by climate change. PG&E identified 36 miles of pipe located in flood-prone areas and near the coastline that could be affected by sea level rise. Cost estimates were based on the vintage pipeline replacement program costs, and the project would be completed over 30 years. PG&E rejected this alternative because there are nearer-term risks to address, and because of low risk reduction and low RSE. Staff agrees with PG&E's decision.

The second alternative seeks to mitigate third-party dig-ins of transmission pipelines. PG&E would install GPS tracking devices on 50 percent of the approximately 14,000 backhoes, excavators, and graders in the State. PG&E would monitor the devices to find when equipment was in proximity to a gas pipeline and then dispatch a regionally based employee to contact the excavation contractor to prevent a dig-in. PG&E assumes that one out of five dig-in events could be prevented by this method.

Observations

The GPS tracking alternative has an estimated RSE of 0.14, a program expense of $34 million over four years and a risk score reduction of 3.4. Those estimates**,** while low in effectiveness, are similar to current mitigations. PG&E has not rejected the idea but has not proposed it either. Third-party excavation is the largest risk driver for pipeline rupture, so this alternative, while challenging to implement, could be an effective approach. PG&E states it will continue to evaluate the idea and may proceed with a pilot program to test the feasibility.

There may be practical difficulties with cooperation and coordination with the owners and operators of several thousand pieces of excavation equipment. The greatest shortcoming may be the time delay from GPS detection to PG&E response. The excavator could begin digging before a PG&E representative can contact them, which may be part of the reason for the expected one-in-five effectiveness. Staff suggests the concept could be expanded to include an on-board alarm for the equipment operator that alerts when a pipeline is nearby.

Summary of Findings

For this set of risks, staff finds that PG&E has followed the expected risk assessment format including the bow tie analysis, risk driver selection, consequence determination, and risk spend efficiency calculation. Staff is concerned that the proposed mitigations have very low risk spend efficiencies and a high cost to ratepayers compared to the existing controls. Although the proposed mitigations would continue from programs approved in previous rate cases, there is now a clear view of the risk spend efficiency of those programs, which gives the Commission the opportunity to consider more effective proposals across the entire PG&E risk portfolio.

Staff notes that the Risk Score of 289 for this risk is 84 times less than the top-ranked Wildfire risk.

This chapter does not discuss whether the risk frequencies based on historical PG&E data have been adjusted for the expected risk level at the start of 2023.

Staff agrees with TURN and MGRA that PG&E's choice of scaling and boundaries for the MAVF have a significant influence on the magnitude of outcomes, for example that equivalent fatalities are valued at ten times greater than the broadly accepted federal figure for Value of Statistical Life.

Recommended solutions to address findings and deficiencies

PG&E should revisit the MAVF calculations based on intervenor recommendations for scaling and ranging of the outcome natural values. The resulting outcomes should produce a new set of risk scores, risk reductions, and RSEs.

The low RSE and high costs should be thoroughly examined by the Commission and intervenors in the TY 2023 GRC. One element to consider is the relative size of this risk, and the spending adopted to reduce it vs. the higher risk items such as Wildfire risk.

PG&E should continue to develop the concept of placing GPS trackers on excavation equipment with the added feature of a built-in alert to the operator if a pipeline is nearby.

RAMP Risk (Ch. 8): Loss of Containment on Gas Distribution Main or Service

Risk Description

This chapter examines the risk that natural gas mains, service pipelines, and service risers in PG&E's Distribution system will lose containment, potentially resulting in human injury, loss of service, and financial loss.

Observations

The risk description is reasonable.

Bow tie

The bow tie presents a risk score of 99, the fifth-highest of the 12 RAMP risks and considerably lower than the scores for the top three risks: Wildfire (24,343), Third-Party Safety (944) and Failure of Distribution Overhead Assets (526).

Observations

Although some parties have objected to PG&E's use of risk event frequency rather than risk event likelihood as the value for LoRE, the bow tie presentation conforms with the Settlement Agreement requirements. PG&E's use of frequency is a practical way of accounting for the consequences of a very large number of events, at more than 29,000 a year.

Exposure

Risk exposure is presented as the combination of total miles of main and service pipeline (112,000 miles), total number of service risers (four million risers) and remaining cross-bore sites that have not been examined (767,000 sites).

Observations

The Settlement Agreement defines exposure in terms of miles of pipe and similar measurements. The total mileage of gas main and service pipeline is large, along with cross-bore sites, due to the extensive area of California covered by the system. The number of PG&E service risers is listed as four million in the narrative but the workpapers present a value of 3.56 million[13]; meanwhile, the PG&E website provides a figure of 4.4 million gas customers. There is a large discrepancy between number of customers and number of risers, which brings into question the correct number to represent exposure for this risk.

[13] Workpaper GO-LOCD-1.

Tranches

PG&E chose to create 12 risk tranches to inform the consequence analysis; they have increased the number of tranches in response to comments from earlier RAMP versions. Plastic pipe is expected to have a different risk profile than steel, and larger population densities near the pipe mean more people are at risk than for lower population densities. PG&E created four tranches for mains and four for service lines, each divided by population high or low and steel vs. plastic pipe material. Two additional tranches focused on service risers in high and low populations, and another two examined cross-bore threats inside and outside San Francisco. Detailed risk scores for each of the tranches is given in PG&E's Table 8-2.

Observations

The tranche with the highest risk score was plastic service lines in high population areas: 20 percent of the total risk. The risk exposure of plastic pipe in high populations is double that of steel.[14] Service lines as a group provide 43 percent of the risk, while gas mains of all kinds contribute 40 percent. The tranche analysis suggests that potential mitigations should be considered for both service lines and main pipelines.

PG&E comments that further subdivision of gas distribution assets in the future is under consideration. For example, the pipe materials could be divided into installation date ranges to better define risk for various pipe ages. That grouping seems appropriate in view of the major proposed mitigations that address vintage pipe material. Staff assumes this approach has not yet been performed due to incomplete data.

Risk Drivers

The risk drivers are chosen from the well-established pipeline threats described in the PHMSA integrity management rule of CFR 49, Part 192 Subpart P: Equipment Failure, Incorrect Operation, Corrosion, Excavation Damage, Material/Weld Failure, Natural Forces, and Other Outside Forces. PG&E added additional cross-cutting threats such as seismic and physical attack, and included the category of cross-bore damage, which is a significant component of the outside force threat.

Observations

Staff finds the risk drivers are appropriate factors contributing to the likelihood of failure, as defined in the Settlement Agreement.

Risk Driver Frequencies

Each driver is assigned a frequency value in terms of events per year based on the likelihood of risk event per unit of exposure (LoRE,) multiplied by the exposure (pipe miles or number of service risers). The event frequency data is taken from PG&E's own data. Seismic event frequency was generated from PG&E's Seismic Earthquake Risk

[14] Workpaper GO-LOCD-1

Assessment "SERA" model (Chapter 20). The baseline year is set to 2023, so the historical data from 2010-2019 was adjusted to account for expected mitigations from 2020-2022.

The large number of events, 29,590, is dominated by gas leaks. Most leaks on the gas distribution system result in minor, if any, consequences. The greatest driver frequency is equipment failure at 65 percent of the total.

Observations

Staff finds the risk driver frequencies are appropriate to quantify the risk drivers and the outcomes.

Outcome Frequencies

Outcomes are divided into categories, such as Minor-Severe, Major-Severe, etc. Each outcome category has an associated frequency. The Major category is based on the PHMSA definition of a significant event, while the Minor category covers non-significant events. The "Minor-Severity Low" outcome category has the highest outcome frequency at 80 percent.

Observations

Staff finds that the outcomes agree with the expectation that most gas leaks on distribution mains, services, or risers will have minor or no consequences.

Cross-cutting factors

PG&E included six cross-cutting factors in the analysis, five of which appear as event drivers. The sixth, emergency preparedness and response, is only a consequence factor. Overall, the cross-cutting factors contribute only 131 of the total 29,590 expected events. However, the cross-cutting sub-driver of Major Seismic has a large impact on outcomes: with only a 0.9 event/year frequency it produces the largest outcome, at 38 percent of the total risk score.

Observations

Staff finds the incorporation of cross-cutting factors is appropriate.

Consequences

According to the PG&E background material in Chapter 3, consequence outcomes were modeled using Monte-Carlo simulations. Those consequences feed into the MAVF risk score calculation. Chapter 8 consequences were based on incident data from both PG&E incidents and PHMSA national incidents, weighted 50-50 because the number of PG&E incidents alone is insufficient to model outcomes with. Consequence scores incorporate safety, reliability, and financial risks. The risk scores are dimensionless numbers that are intended to allow comparisons between one risk and another, and to support measurement of risk level changes. Table 8-4 of the RAMP Report breaks down the consequences into natural units, such as equivalent fatalities for the safety risk, dollars for financial risk, etc. The safety consequence for all risk drivers combined is 1.176 equivalent fatalities per year, which corresponds to a safety score of 72. This safety score component is the largest contributor to the total risk score of 99.

The highest consequence category is “Major-Seismic” with a CoRE of 44 and a frequency of occurrence of 0.003 percent. The expected natural unit safety outcome for this event is 0.57 equivalent fatalities a year, about half of the total safety consequence.

Observations

Staff finds that the outcomes are consistent with expectations of risk for gas distribution systems and follow the Settlement Agreement guidelines.

Controls and Mitigations

Controls

Existing controls are based on the gas safety rules in CPUC GO-112F, which incorporates the PHMSA code in CFR Title 49 Part 192. All the controls were in effect in the 2017 RAMP and are expected to continue. Such controls include leak survey and repair, corrosion control, preventive maintenance, and training.

One new control entitled Distribution Integrity Management Program (DIMP) is proposed for this RAMP period. The program began as a mitigation in 2017-2019 and is expected to become a control in 2021. This mitigation developed as the “DIMP Emergent Work” program from an analysis performed under the DIMP rule of 49 CFR Part 192. PG&E determined that an emerging threat to pipeline integrity required the replacement of curb valves in the city of San Francisco. Hundreds of curb valves have already been replaced as a mitigation. Staff expects the change to a control program in 2021 is planned because the bulk of known valves will have been mitigated by then.

Mitigations

Five current programs are proposed to continue for the 2023-2026 period. A new fitting mitigation program begins in 2023. This program will mitigate plastic fittings known to have a high failure rate due to manufacturing defects.

Two of the mitigations, for replacement of vintage steel and vintage plastic pipe materials, have been reclassified from controls to mitigations since 2020 because they have a finite end; they are not expected to continue as control programs.

Risk Spend Efficiency for Controls and Mitigations

For each mitigation and for one of the controls, PG&E offers an RSE value. The RSEs are expected to guide decision makers in the TY 2023 GRC on whether to approve ratepayer funding for the proposed mitigations. Some mitigations may offer more cost-effective risk reduction than others.

Observations

This chapter provides one of the few instances where PG&E has provided an RSE value for a control program, which can serve as a benchmark to compare new mitigation proposals. RSE is the ratio of risk score reduction divided by the cost to achieve the reduction (multiplied by a scaling factor of 1000 for readability). The leak management control program has an RSE of 0.716. The RSE for the leak management control program was calculated from the risk increase if the control program was stopped. PG&E stated there was not enough time to determine RSE for the other control programs.

The proposed mitigations have considerably lower efficiencies than the example control program as shown in Table 8-1.

TABLE 8-1. Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026

Program	Expense ($000s)	Capital ($000s)	Risk Score Reduction	Risk Spend Efficiency
C4 Leak Management (control)	291,957	-	153.6	0.716
M2 New Valve Installations	-	30,314	2.1	0.095
M4 ECISS (isolated steel)	4,161	-	<0.001	<0.001
M5 Pipeline Replace (Steel)	-	771,707	10.1	0.018
M6 Pipeline Replace (Plastic)	-	2,398,295	35.8	0.021
M7 Cross Bore Legacy Inspect.	128,880	-	3.7	0.04
M8 Fitting Mitigation	59,881	-	2.3	0.05

The most expensive mitigation, M6 plastic pipeline replacement, has an RSE of 0.021 at a cost of $2.4 billion over four years. The steel replacement program, M5, has a similar RSE of 0.018 at a cost of $0.77 billion. These mitigations are on average 37 times less effective than C4 leak management. The proposed M6 plastic pipeline cost is in addition to the $1.1 billion already forecasted for 2020-2022.

The risk score reduction for M6 plastic pipeline replacement of 35.8 is roughly one-third of the current risk score of 99. The largest attribute of the risk score as shown on the 2020 RAMP Table 8-4 is safety: 72 out of 99. The safety attribute is based on the natural unit outcome of approximately 1.2 equivalent fatalities (EFs). If the safety score is reduced by one-third, the expected EFs would decrease from 1.2 per year to 0.8 per year at a cost of $2.4 billion. Over a l 30 year period, this reduction avoids 12 equivalent fatalities, which roughly equates to a cost of $200 million per EF on a non-discounted basis. This cost is many times the commonly accepted Value of Statistical Life of about $10 million.[15]

In this RAMP chapter, PG&E provides support for continuation of the plastic pipeline replacement program, citing testimony in the 2020 GRC of CUE[16] and OSA[17] advocating replacement at a greater rate than proposed by PG&E. The current RAMP proposes to continue replacement at the 2020 rate case settlement agreement level.

Staff has learned from a data request response that the pre-1985 plastic replacement program is expected to continue beyond this rate case period until 100 percent of all vintage plastic pipe is replaced. This RAMP highlights that the program has a very high cost and very low risk spend efficiency.

In 2014, the CPUC's Risk Assessment and Safety Analytics section (RASA) published a report on Aldyl A pipeline risk.[18] Aldyl A is the Dupont tradename for the primary type of plastic pipe installed before 1985. The report found that different vintages of pre-1985 plastic pipe carry varying levels of risk and advised utilities to base their risk mitigation plans on the specific years of installation and plastic material composition. A better approach to mitigate pre-1985 plastic pipe risk would be to determine the specific vintage and plastic composition of the pipe before committing to an expensive excavation and replacement of pipe that may present no particular risk.

In response to Staff's data request PG&E confirmed that the M6 plastic pipeline replacement mitigation expects to replace 100 percent of vintage plastic regardless of the conditions of a particular segment. For example, Aldyl A is known to be more susceptible to failure due to stress created by rocky soil, excessive bending, or squeezing. Will the condition of segments be considered to determine replacement? The Commission and intervenors should seek more detail in the TY 2023 GRC.

Alternatives Analysis

PG&E presents two alternative mitigations, considered in combination with the other proposed mitigations. Evaluation included cost, risk reduction, and RSE.

The first alternative is to apply fire retardant coating on above-ground, encased plastic distribution pipe spans in high fire threat districts. Only 3.9 miles of the entire PG&E

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[15] A common example of the Value of Statistical Life is published by the Department of Transportation: https://www.transportation.gov/office-policy/transportation-policy/revised-departmental-guidance-on-valuation-of-a-statistical-life-in-economic-analysis. The guidance VSL was $9.3 Million in 2016.

[16] CUE: Coalition of Utility Employees

[17] OSA: Office of Safety Advocates, CPUC.

[18] Hazard Analysis and Mitigation Report on Aldyl A Polyethylene Gas Pipelines (https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=8947)

distribution system fall into this category. PG&E rejected this alternative based on low risk reduction and low RSE.

The second alternative would remove vintage plastic and steel gas pipe and replace it with all-electric service. This approach would contribute to the overall State goals of reducing fossil fuels and greenhouse gas emissions. For this alternative, PG&E provided a cost estimate for “deactivating pipelines and retrofitting homes based on readily available cost data.” For the purposes of this RAMP Report, PG&E made far-reaching assumptions including that:

a. Pipeline deactivation would not impact gas system hydraulics;
b. All additional investment in existing gas customers would cease;
c. No upgrades to the electrical system would be necessary for the additional load;
d. Electrification would be 100 percent effective in reducing all gas distribution mains and services risk drivers; and
e. Potential risks to the electric system were not considered in the risk model.

Observations

Staff agrees with PG&E’s rationale for rejection of the electrification alternative, and PG&E’s statements that: “Implementing this alternative involves higher costs compared to just pipe replacements. Additionally, this alternative would require new laws mandating all customers agree to the conversion. PG&E is not pursuing this alternative to its full extent due to customer affordability impacts and limitations on their ability to mandate fuel source options, as well as regulatory and feasibility limitations. While PG&E is choosing not to implement this program at this time, PG&E will continue to evaluate the feasibility of converting individual projects to electric service on an individual project basis.”

Summary of Findings

Staff finds that PG&E has followed the expected risk assessment format including the bow tie analysis, risk driver selection, consequence determination, and risk spend efficiency calculation. Staff is concerned that the proposed mitigations have very low risk spend efficiencies and a high cost to ratepayers compared to the existing controls. Although the high-cost vintage pipeline replacement mitigations would continue from programs approved in the previous rate case, there is now a very clear view of the risk spend efficiency of those costly programs, which presents the Commission with the opportunity to consider their merits of these efforts in comparison to other more effective proposals across the entire PG&E risk portfolio. Staff notes that the Risk Score of 99 points for this risk is 240 times less than the top-ranked Wildfire risk.

Staff finds that the tranches chosen are logical groupings of assets with similar risk profiles, but these tranches could be further divided to better assess risk.

Staff is concerned that the number of risers chosen for exposure purposes does not match the reported number of gas customers. Normally each customer should have a riser. The 2020 RAMP value of 3.56 million may under-represent exposure if there are 4.4 million gas customers served.

Staff agrees with intervenors that PG&E's choice of scaling and boundaries for the MAVF have a significant influence on the magnitude of outcomes; for example, equivalent fatalities are valued at ten times greater than the broadly accepted Federal figure for Value of Statistical Life.

Recommended solutions to address findings and deficiencies

Staff recommends that PG&E should revisit the MAVF calculations based on intervenor recommendations for scaling and ranging of the outcome natural values. The resulting outcomes would produce a new set of risk scores, risk reductions, and RSEs.

Staff recommends that the low RSE and high costs should be thoroughly examined by the Commission and intervenors in the upcoming GRC. The relative size of this risk, and the spending adopted to reduce it, should be compared to higher risk items such as wildfire.

Tranches should be chosen to align with groups of assets that have known risk distinctions. PG&E has identified vintage pipe materials as higher risk than non-vintage and has proposed mitigations to address them. It would be logical to create tranches for such material differences.

The discrepancy between gas riser exposure and number of gas customers should be explained by PG&E.

RAMP Risk (Ch. 9): Large Overpressure Event Downstream of Gas Measurement and Control Facility

Risk Description

This chapter examines the risk that a Measurement and Control (M&C) pressure regulation facility will fail to control downstream gas pressure below the maximum safe level. When that level is exceeded, the pipe may leak or rupture. Both transmission and distribution facilities are included in this chapter. A large overpressure (OP) event is defined by the extent that the maximum allowable operating pressure (MAOP) has been exceeded, according to CPUC/PHMSA definitions.

Bow tie

The bow tie analysis presents a risk score of 13. This score is the second lowest of the twelve RAMP risks and considerably lower than the top three risks: Wildfire (24,343), Third-Party Safety (944) and Failure of Distribution Overhead Assets (526).

Observations

The low risk score is reflective of the design of gas pipeline pressure control systems. California gas safety regulations dictate design standards that support safe operation. Measurement and control facilities normally have an overpressure protection (OPP) device installed downstream of the main regulator, so both must fail to lose control of gas pressure.

Staff notes that the relative risks scores may change depending on the results of the intervenor's suggestion to alter the MAVF scoring parameters.

Exposure

The total exposure is 4,624 M&C stations. These stations contain pressure regulation equipment that controls gas pressure downstream of the stations.

Observations

There are many stations installed on the thousands of miles of PG&E transmission and distribution pipelines. The exposure parameter is consistent with the Settlement Agreement definition. The more stations overall, the greater the risk.

Tranches

PG&E chose six tranches grouped by homogenous risk profile for this chapter's risk assessment, three for transmission and three for distribution. The transmission tranches are Complex Stations, Simple Stations, and Large Volume Customer Regulator Stations. The distribution tranches are Normal District Regulator Stations, Low-Pressure Stations, and District high pressure regulator and Farm Tap Stations.

Observations

Transmission stations regulate much higher pressures and thus have greater risk than distribution stations. Within the transmission station group, complexity and specialized function are tranche distinctions. For distribution, the tranches are divided by pressure level and regulator design. SPD staff agree these are logical groupings for risk assessment.

However, RASA staff believes greater granularity is possible. For example, the risk from larger diameter and/or higher-pressure transmission lines after a leak or rupture is greater than for smaller/lower pressure transmission lines, which could provide additional tranche groupings. Additionally, staff review of the proposed mitigations and alternatives suggests that the risk for single-run distribution regulator stations that serve 5,000 or more customers is different than the risk for those that serve fewer customers.

Risk Drivers

Two drivers and two cross-cutting drivers contribute to the analysis. PG&E explains that other kinds of pipeline risk drivers established in industry standards like ASME[19] B31.8 S can lead to loss of containment, but this chapter is only concerned with the failure of pressure regulation devices. The two main drivers are Equipment Failure and Incorrect Operations.

Risk Driver Frequencies

PG&E used actual company data for large OP events to determine driver frequencies from the 2012-2019 period. Equipment Failure was the most frequent at 66 percent. Incorrect Operations accounted for 30 percent. The driver frequency adjusted for the 2023 baseline is 5.6 events per year

Observations

The low number of driver events is reasonable considering that the system is designed to prevent overpressure of the pipelines. RASA Staff agrees that it is logical that most of the failures are related to equipment failure rather than the human errors represented by Incorrect Operations.

Outcome Frequencies

The most frequent outcome from the risk model is benign, at 94 percent of the results. Benign means the pipe material withstands the overpressure with no loss of containment or other safety hazard. However, such events can incur financial and reliability risks since the operator may have to take action to assure the continued safety of the downstream pipe and curtail deliveries until allowed to resume operations.

[19] American Society of Mechanical Engineers.

Loss of Containment accounts for the remaining six percent of the outcomes, while results from the cross-cutting drivers add to 0.1 percent.

Observations

Outcome frequencies are presented by tranche in PG&E's RAMP Table 9-2. The highest contributor to total risk is the Transmission Complex Station tranche at 36 percent. While the exposure for that tranche is small at 131 stations or three percent of the total, the high score for reliability appears to drive the overall result. The next highest frequency is for Transmission Simple Stations at 23 percent.

Cross-Cutting Factors

Two cross-cutting drivers impact likelihood while four affect outcomes. Record Keeping Information Management (RIM) and Skilled and Qualified Workforce (SQWF) are risk drivers which contribute to three percent of the events. The total impact on outcomes of cc-factors is 1.6 percent.

Observations

RASA Staff agrees that the cross-cutting factors are appropriate to the risk and it is reasonable they would not have as large an impact as the two main drivers.

Consequences

The PG&E risk model predicts very limited consequences from this risk, which drive the low risk score of 13. The largest component of the risk score is reliability, rather than safety, due to loss of gas service.

Observations

Pressure control is a primary focus of gas safety regulations, so exceeding the MAOP should be a rare event. PG&E's data for the eight years 2012-2019 totals 64 large OP events, for an average of 8 per year. This chapter's 2023 baseline event frequency of 5.6 per year predicts that mitigations in 2020-2022 will reduce the number of events.

While small compared to other risks, the largest safety risk for this chapter comes from the tranche with the greatest exposure, the 2,608 high-pressure district regulator stations on the distribution system. These stations have the largest exposure at 56 percent of the total number of stations, so it is reasonable that they would have a substantial impact.

The choice of tranches may not be granular enough to model the difference in outcomes; for example, models may not show a discernable difference between when a high-pressure transmission pipeline has a rupture with fire in a highly populated area versus a lower-population area. While this risk is focused on the loss of pressure control, if a loss of containment (LOC) occurs then the risk should be modeled at the same tranche level as the other LOC chapters. Such an analysis may not change the results significantly due to the high percentage of benign outcomes but would be closer to the level of rigor expected in the Settlement Agreement.

Controls and Mitigations

Controls
Seven existing control programs are proposed to continue in the 2023-2026 period: C1 Corrective Maintenance, C2 Gas Quality Assessment, C3 Preventive Maintenance, C4 Regulator Station Component Replacements, C5 Reg. Station Rebuilds, C6 Other Operations and Maintenance, and C7 Foundational Activities. One of these, C2, will be combined into C4 going forward.

Observations
Staff notes that controls for this risk are related to required inspections of pressure regulation devices and are well-established activities to reduce likelihood of equipment failure. The gas quality assessment program is important because contaminants in the gas supply can impair performance of pressure regulation devices. For example, excess sulfur dioxide in the gas can deposit solid sulfur on regulator surfaces which prevents full closure of the regulator when pressure is above the set point. Staff finds the controls are reasonable.

Two of the programs, Regulator Station Rebuilds and Regulator Station Component Replacements, are also part of the Steady State replacement programs described in Chapter 21.

None of the controls had an RSE provided, which, as noted in prior chapters, would have been helpful to rank the proposed continuation of controls and the proposed mitigations.

Mitigations
Three existing mitigations are proposed to continue into the 2023-2026 period, while PG&E considers that the current M1-Critical Documents program will be completed before 2023. The three mitigations are aimed at replacement of obsolete equipment or addition of new safety devices: M2-HPR Replacement, M3-SCADA Visibility, M4-OPP Enhancements.

Observations
The M2 mitigation is aimed at replacement of obsolete distribution system "HPR" (High Pressure Regulator) equipment, typically used on farm taps. The replacement devices are said to be less prone to operator error, in addition to reducing likelihood of equipment failure.

M3-SCADA Visibility seeks to add more measurement points on the pipelines to be monitored by the Gas Operations Control Center SCADA system. Remote monitoring of pipeline pressure before and after regulating stations will alert Control Center operators to abnormally low or high pressures so that appropriate measures to avoid risk can be taken.

The M4-OPP Enhancements mitigation improves OPP (overpressure protection) at certain types of regulating stations found to have higher risks than others; pilot-operated stations will be enhanced with slam-shut devices while large-volume customer primary regulator sets will be rebuilt.

Staff is concerned that the sub-categories of M&C stations targeted by M4 should be considered as separate tranches for risk analysis, since PG&E has identified them as targets for specific mitigations.

Risk Spend Efficiency

RSE and risk score reduction is presented for the three proposed mitigations as shown in the Table below.

TABLE 9-1. Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026

Program	Expense ($000s)	Capital ($000s)	Risk Score Reduction	Risk Spend Efficiency
M2-HPR Replacement		74,167	1.6	0.029
M3-SCADA Visibility		95,471	1.9	0.025
M4-OPP Enhancements	21,087	71,352	14.9	0.197

Observations

The best RSE is for M4 at 0.197, considerably higher than the other two mitigations and in a similar cost range. The M4 risk score reduction is almost ten times better than M2 and M3.

However, there are questions about M4 concerning the feasibility for some categories of regulator stations to receive the planned slam-shut OPP enhancement device that are discussed under Alternative 1.

Staff agrees with intervenors that PG&E's choice of scaling and boundaries for the MAVF have a significant influence on the magnitude of outcomes, for example that equivalent fatalities are valued at ten times greater than the broadly accepted Federal figure for Value of Statistical Life. In this chapter, the low safety risk score would then be even lower, further reducing the effectiveness of proposed mitigations.

Alternatives Analysis

P&E states that some of the regulator stations that are planned to have the M4 OPP slam-shut device installed may not be appropriate for that enhancement, so they propose an alternative solution. The inappropriate stations are those "that meet all the following criteria: they are considered critical from a reliability or customer perspective, they feed over 5,000 customers, and they are single-run stations".

A slam-shut device completely shuts off gas flow; the standard dual-run station incorporates secondary pressure regulation that controls pressure within limits and keeps customers supplied.

The alternative considered would be to rebuild all 640 of the 1,100 single-run Distribution District Regulator Stations (DRS) into dual-run stations rather than have a slam-shut installed. PG&E rejected this alternative because the pace of building dual-run stations would only be 30 per year, which would not satisfy PG&E's goal of completing secondary OPP for all the stations by 2027. The RSE for this alternative is 0.02, much lower than the proposed mitigation M4.

Observations

For Alternative 1, it is not clear what will happen to the stations that are not considered appropriate for the slam-shut device if the proposed mitigation M4 were to be adopted. How many of the 640 single-run stations are not appropriate for M4? Will they have no secondary OPP installed and remain at risk for large overpressure events?

PG&E states that the non-appropriate stations would need separate projects to investigate viable secondary OPP. When will those projects be initiated? Why aren't they part of the proposed mitigations for this RAMP?

Alternative 2 is a variation of Alternative 1, but simply states that only some of the single-run stations would be rebuilt, while the rest would be retrofitted, to achieve the goal that all distribution pilot-operated regulator stations would be addressed by the end of the next rate case period (2027). PG&E rejected this alternative because the RSE is lower than the proposed plan.

The RSE for Alternative 2 is 0.02, which is indeed lower than the proposed M4 mitigation RSE of 0.197. However, this plan seems to address all the issues brought up in the Alternative 1 discussion. Since M4 has the preferred RSE, what will happen to the stations that are not appropriate for rebuild or retrofit?

Summary of Findings

PG&E has followed the steps outlined in the S-MAP Settlement Agreement in this chapter. Large overpressure events have a low risk score due to required system designs. The largest attribute of the score is Reliability, even with Safety weighted at 50 percent.

Staff agrees with intervenors that PG&E's choice of scaling and boundaries for the MAVF have a significant influence on the magnitude of outcomes; for example, equivalent fatalities are valued at ten times greater than the broadly accepted Federal figure for Value of Statistical Life. In this chapter, the low safety risk score would then be even lower, further reducing the effectiveness of proposed mitigations.

The Risk Spend Effectiveness for mitigation M4, at 0.197, is one of the higher values for the three gas chapters. However, staff review of the Alternative mitigations raises a concern about which regulator stations would be given secondary OPP under the M4 program. It is not clear what PG&E intends to do with stations considered inappropriate for the slam-shut solution.

The grouping of M&C stations into tranches of similar function is logical but may not be granular enough to account for different loss-of-containment outcomes considering conditions of the pipelines downstream of the stations.

Recommended Solutions to address findings and deficiencies

PG&E should clarify what the proposed M4 program will do in the case of regulator stations considered inappropriate for retrofit of slam-shut devices. How many stations will be left out of the mitigation?

Staff recommends that PG&E should revisit the MAVF calculations based on intervenor recommendations for scaling and ranging of the outcome natural values. The resulting outcomes should produce a new set of risk scores, risk reductions, and RSEs.

Staff recommends that the same tranches chosen for the LOC chapters should be applied to this chapter as sub-groupings of the M&C Station tranches to better model outcomes for loss-of-containment events.

RAMP Risk (Ch. 10): Wildfire

Risk Description

Chapter 10 focuses on Wildfire risk, defined as PG&E assets or activities that may initiate a fire that is not easily contained and endangers the public, private property, sensitive lands, or the environment. Fire ignitions and associated impacts unrelated to PG&E electric system assets are not within the scope of the Wildfire risk chapter.

Approximately 99,000 overhead primary circuit miles in PG&E's electric distribution and transmission system are potential sources of wildfire ignition. More than 30 percent of assets are in High Fire Threat Districts (HFTD). The impacts of climate change coupled with increased development in formerly wildland areas and decades of fire suppression have led to increased consequences from wildfire ignitions – 15 of the 20 most destructive wildfires in California's recorded history have occurred since 2000 and 10 have occurred since 2015. Moreover, PG&E faces significant wildfire challenges because of the size and geography of its service area. PG&E has 5.5 million electric customers across a service territory of approximately 70,000 sq. miles, more than half of which is included in HFTDs.

Observations

Wildfire risk continues to grow in California: five of the 20 most destructive fires in the state's recorded history burned in 2020. Powerlines were conclusively found to be the ignition source for six of California's top 20 most destructive wildfires.[20] Four of the six, including the most destructive wildfire in California's history (the 2018 Camp Fire), were found to be caused by PG&E's powerlines. Any fire ignited in HFTD areas, particularly during red flag warnings and other fire hazard conditions, has a significant risk of causing a destructive, or worse, catastrophic, wildfire. The smoke and particulates from wildfires can also cause unhealthy or hazardous air quality for many Californians living in and outside PG&E's territory. As a result, wildfire risks are appropriately the top safety risk for PG&E's 2020 RAMP Report.

Bow tie

PG&E's MAVF bow tie for its wildfire risk analysis is based on wildfire exposure risks in PG&E's entire transmission and distribution overhead electric system. The wildfire MARS for the entire overhead electric system is 25,127, which represents the pre-mitigation risk score for 2023, post 2020-2022 mitigations and post all controls.[21] (MARS attributes include Safety, Reliability, and Financial Attributes.) This far surpasses

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[20] CAL Fire, "Top 20 Most Destructive California Wildfires," https://fire.ca.gov/media/11417/top20_destruction.pdf (updated November 3, 2020)

[21] Reference PG&E MS Excel file Bowtie v.1.1_WF_errata (July 17, 2020

the second and third highest risks, Third-Party Safety (944) and electric Distribution Overhead (DOH) assets (526).

PG&E included a second wildfire risk bow tie for exposure relevant to only the portion of the system that lies in HFTD areas to show how wildfire risk characteristics differ from non-HFTD areas. Using the HFTD-only bow tie, PG&E calculated a Wildfire MARS of 25,008 for the portion of the system that lies in HFTD areas.

PG&E's risk assessment forecasts 442 annual risk events (ignitions) from 2023-2026 for the entire overhead electric system and 141 risk events per year from 2023-2026 for the portion of the system that lies in HFTD areas.

The 2020 RAMP wildfire risk bow tie differs from the 2017 RAMP risk bow tie in several important ways:

- For exposure, the 2020 bow tie is for PG&E's entire overhead (OH) Transmission and Distribution (T&D) system instead of just the Fire Index Areas (FIA) considered in the 2017 bow tie.
- The frequencies in the 2017 bow tie were based on 2015-16 ignitions reported to the CPUC; the frequencies in the 2020 bow tie are based on reportable ignitions data required by D.14-02-015 Guidelines for 2015-2019, including data from seven additional fires that were not included in PG&E's annual report of ignitions to the CPUC because they were under investigation at the time the report was submitted.
- The 2017 bow tie had several drivers related to equipment failure; the 2020 bow tie has one equipment failure driver but continues to capture the different types of equipment failure as sub-drivers.
- The 2020 bow tie also includes a Seismic Scenario driver that was not present in the 2017 bow tie.
- In the 2017 bow tie, PG&E considered consequences based on categories of overall impact, (e.g., Safety, Reliability, Financial). The 2020 bow tie considers consequences with more granularity based on eight individual tranches in terms of the frequency and risk impact attributable to ten different combinations of fire size and weather conditions, including fires associated with a potential seismic event, all in combination for an aggregated risk score.

Observations

The Wildfire risks for Electric Operations is far and away the largest risk analyzed in this RAMP. The Wildfire MARS is more than 26 times greater than the second-ranked Third Party Safety Incident MARS Score. The overall MARS ranking is appropriate given that wildfire is currently, and for the foreseeable future, PG&E's top safety risk.

HFTD areas account for 99 percent of the wildfire risk. The forecasted risk events are based on 2015-2019 historical ignitions with adjustments. For comparison, PG&E calculated the MARS for the portion of the system only in HFTD areas as 25,008. Since this is more than 99.53 percent of the MARS of 25,127 for the entire OH electric system, SPD finds that wildfire bow tie risk analysis using the entire service territory for its exposure allows for MARS to be heavily allocated to PG&E's HFTD wildfire risk tranches. As PG&E explained, in their 2017 RAMP, PG&E only assessed risk in their Fire Index Areas (before HFTD areas were defined) but they expanded their risk analysis for their entire territory per statutory requirement. Since 99.5 percent of the Wildfire risk is in their HFTD areas, PG&E must ensure that MAVF modeling capabilities are fully utilized to sufficiently focus risk analysis on these areas.

Exposure

Exposure to Wildfire risk is based on approximately 81,000 miles of distribution primary overhead circuits and about 18,000 miles of transmission overhead circuits, all of which are included in the current Wildfire operational risk model as required for the Wildfire Mitigation Plans (WMP).

The total HFTD exposure is 30,936 circuit miles of overhead (OH) distribution and transmission assets including 25,400 distribution and 5,525 transmission OH circuit miles. PG&E also lists substations as exposure risks including 203 in HFTD which include switching stations and other facilities. PG&E assigned one circuit mile for each substation for modeling purposes.

In relation to other CA utilities, 51 percent of the share of all CA IOUs HFTD Tier 3 exposure is within PG&E's service territory. Additionally, 76 percent of the share of all CA HFTD Tier 2 is in PG&E's service territory.

Tranches

PG&E identified eight tranches for Wildfire risk that they state reflects similar risk profiles.

The eight tranches presented in PG&E's RAMP MAVF risk analysis are:

- <u>HFTD Areas – Distribution (Hardened)</u>: n=171 circuit miles or < one percent of system mileage.
- <u>HFTD Areas – Distribution (To be Hardened)</u>: n=6,929 circuit miles or seven percent of system mileage.
- <u>HFTD Areas – Distribution (Remainder)</u>: n=18,310 circuit miles or 19 percent of system mileage.
- <u>HFTD Areas – Transmission</u>: n=5,525 circuit miles or six percent of system mileage.
- <u>HFTD Areas – Substation</u>: n = 1 circuit mile representing 203 of 942 total substations.

- Non-HFTD Areas – Distribution: n=55,300 circuit miles or 56 percent of system mileage.
- Non-HFTD Areas – Transmission: n=12,600 circuit miles or 13 percent of system mileage.
- Non-HFTD Areas – Substation: n=1 circuit mile representing 739 of 942 substations.

Observations

Two HFTD Distribution tranches, with about 25,000 circuit miles, account for more than 92 percent of the total wildfire MARS as follows:

- HFTD Distribution (To Be Hardened) is seven percent of Exposure Risk (by total PG&E Overhead Distribution & Transmission miles) and more than 45.4 percent of the MARS; and
- HFTD Distribution (Remainder) is 18.5 percent of Exposure Risk and 47 percent of the MARS.

The HFTD Transmission Tranche, with more than 5,500 circuit miles, accounts for 6.5 percent of the total wildfire MARS. These three HFTD tranches together, with 98.93 percent of the total wildfire Risk Score, include more than 30,000 circuit miles or more than 30 percent of PG&E's total overhead Distribution and Transmission circuit miles.

The S-MAP Settlement Agreement defines a tranche as "a logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment." With respect to Mitigation Analysis for Risks in RAMP, the Definition of Risk Events and Tranches element requires IOUs to "strive to achieve as deep a level of granularity as reasonably possible."[22] In consideration of PG&E's RAMP filing, extensive discussions in RAMP Workshops, Scenario Analysis informal workshops in September and October 2020 and Intervenor informal comments, staff finds that PG&E should provide as much granularity as reasonably possible, particularly for the three highest risk scored HFTD wildfire risk tranches for the TY2023 GRC filing. SPD finds that PG&E should consider how to model these three high Multi-Attribute Risk Score tranches with more granularity and specifically with significantly less circuit miles in each tranche for the TY2023 GRC.

In prior comments, staff found that "All HFTD wildfire risk tranches are insufficient and require significant further granularity."[23] Staff listed the following to support their finding:

- All five HFTD tranches should be minimally separated into Tier 3 and Tier 2 tranches.

[22] Decision 18-12-015 Attachment A, S-MAP Settlement Agreement, Row 14, pg. A-11.

[23] On July 29, 2020, SPD issued an agenda item, dated July, 28, 2020 for the July 30 PG&E RAMP Wildfire Risk Mitigation Plan Workshop which included initial SPD identified deficiencies.

- Having only three T&D HFTD tranches, which encompass more than 30,000 circuit miles, is insufficient for risk analysis since circuit risks, equipment risks, vegetation contact risks and other risk profiles within these existing tranches lack homogeneity.
- Prioritization modeling for vegetation management, equipment maintenance and replacement, and circuit prioritization for covered conductors are examples of tools that can be utilized to divide tranches into more granular, homogenous risk profiles.
- The tranches utilized in other electric operations RAMP risks provide examples of existing tranches that, if divided into the four HFTD T&D circuit miles, could result in more granular risk profiles.
    - For example, the five tranches for failure of electric distribution OH assets (e.g. Small Conductors 22k+ circuit miles; High/Mod/Poor reliability performance circuits; and ACSR circuits in corrosion zones) may have risk profiles related to wildfire risks and may improve tranche granularity if used to further refine current tranches especially if based on momentary and sustained outages, often indicative of electrical faults.
- Regionalized or localized tranches would result in more localized wildfire mitigations.

Staff understands that further dividing HFTD into Tier 3 and Tier 2 tranches may not be reasonably possible due to circuits traversing multiple Tiers. SPD suggests PG&E consider other methods to further divide the three largest wildfire risk tranches relevant to the likelihood and consequences of wildfire risks. The Settlement Agreement requires PG&E to subdivide its group of assets or its system into tranches to demonstrate how mitigations will reduce wildfire risks. PG&E is required to base the determination of tranches on how the wildfire risks and assets are managed by the utility, data availability, and model maturity, and to strive to achieve as deep a level of granularity as reasonably possible.

PG&E's determination of wildfire risk tranches by dividing wildfire risks based on whether they are in HFTD or non-HFTD areas is supported by the CPUC's D.17-12-024, which adopted regulations to enhance fire safety in the HFTD including the new HFTD map consisting of three areas (Zone 1, Tier 2 and Tier 3) to General Order 95. As stated in D.17-12-024, HFTD Tiers 2 and 3 consists of areas where there is an elevated or extreme risk (including likelihood and potential impacts on people and property) for destructive utility-associated wildfires.

However, staff believes additional granularity would improve the analysis. Specifically, SPD suggests PG&E further divide its overhead Distribution and Transmission powerlines by some appropriate combination of (1) assets and (2) subsystems of its very large electric system by geographic location relevant to wildfire risks.

For PG&E's distribution system, assets can be first divided into tranches by classifications. PG&E has already done this by identifying only circuit miles that are overhead power lines as having wildfire exposure, excluding underground power lines. Additionally, PG&E should consider dividing their assets by system voltage and perhaps by scheme of connection (i.e. radial, loop, network, multiple or series) and number of conductors (2-wire, 3-wire, 4-wire, etc).[24] PG&E could also evaluate dividing their assets by load types (residential, commercial, street lighting, railways, etc.) in instances where this could help further tranche assets. If PG&E divides its assets into groups of classification, such as a group for all 12.47 kV overhead lines and assets, then PG&E MAVF risk analysis would provide more specific MA risk scores for these types of assets and proposed mitigations could be assessed by risk reduction scores specific to these assets/subsystems.

Staff recommends PG&E consider all ways that would provide granular tranches for MARS and proposed mitigations for reducing risk scores to be as granular as possible. Since primary circuits or "feeders" are one of the main elements of a typical distribution system usually operating in the range of 4.16 to 34.5 kV and supplying the load in a well-defined geographical area,[25] HFTD Distribution overhead circuit lines could be tranched by types of primary circuits or line sections if the risk profiles of the feeder(s) and/or circuit segment(s) is deemed to be homogenous. If the feeder is deemed to have varying degrees of risk profiles, then a feeder (i.e. asset) could be divided into its line sections for allocating its sections to appropriate individual Tranches.[26] Alternatively, PG&E could consider tranching circuits by groups of 'zones of protection' rather than line sections if there are a definitive clear endpoint for each zone.[27]

PG&E's rationale for the determination of its two very large HFTD Distribution Tranches was to capture the circuit miles that it proposes to "harden" from 2020 through 2026 within PG&E's HFTD along with the remainder of planned unhardened overhead lines in its HFTD. PG&E's identification of these two Distribution Tranches, along with the third much more granular HFTD Distribution Tranche that includes only 171 circuit miles that were hardened in 2019, is based on the CPUC's identification of HFTD in PG&E's service territory.

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[24] Standard Handbook for Electrical Engineers, 13th Edition, Donald G. Fink / H. Wayne Beaty, p 18-5.

[25] Standard Handbook for Electrical Engineers, 13th Edition, Donald G. Fink / H. Wayne Beaty, p 18-2.

[26] A line section is defined by IEEE Std 100-1992 to be "a portion of an overhead line or a cable bounded by two terminations, a termination and a tap point, or two tap points."[26] Since IEEE Standards Association (SA) no longer maintains Std 100 and has transitioned to an online dictionary, the only definition included in an active standard currently is from IEEE Std 1547.7-2013, IEEE Guide for Conducting Distribution Impact Studies for Distribution Resource Interconnection. Per IEEE Std 1547.7-2013, Line Section is defined as "The smallest Area electric power system (EPS) section that could be energized by the distributed resource (DR)."http://dictionary.ieee.org, available with a free IEEE account

[27] Zones of protection are logical divisions of the power system used to isolated faulted sections, i.e., generators, transformers, buses, transmission lines, distribution lines or cable circuits, and motors. Zones are classified as primary and/or backup. IEEE Std 3004-2016 http://dictionary.ieee.org

As seen in PG&E's Bowtie data shown in Table 10-1 below, the HFTD – Distribution Hardened tranche, with 171 circuit miles of exposure (0.17 percent) has a MARS of 150 or 0.6 percent of the total wildfire MARS of 25,127.

TABLE 10-1. Multi-Attribute Risk Scores by Tranche

Risk	Tranche	Aggregated	Electric Reliability	Financial	Safety	Percent Risk Score	Percent Exposure
Wildfire	HFTD - Distribution - Hardened	150.07	5.65	85.80	58.62	0.60%	0.17%
Wildfire	HFTD - Distribution - To Be Hardened	11411.04	422.45	6455.65	4532.95	45.41%	7.01%
Wildfire	HFTD - Distribution - Remainder	11811.48	444.81	6763.12	4603.55	47.01%	18.53%
Wildfire	HFTD - Transmission	1635.13	60.27	938.86	636.00	6.51%	5.59%
Wildfire	HFTD - Substation	0.00	0.00	0.00	0.00	0.00%	0.00%
Wildfire	non-HFTD - Distribution	114.35	15.64	74.79	23.92	0.46%	55.95%
Wildfire	non-HFTD - Transmission	4.35	0.62	2.87	0.86	0.02%	12.75%
Wildfire	non-HFTD - Substation	0.08	0.01	0.05	0.02	0.00%	0.00%
Total Multi-Attribute Risk Score (MARS)		25127					

Since these circuit miles had covered conductor and other hardening completed in 2019, this tranche has a lower risk profile than the other HFTD Distribution tranches and therefore a much lower MARS. On the other hand, it is unlikely that the two non-Hardened HFTD Distribution tranches – with MARS of 11,411 and 11,811, respectively – have homogenous risk profiles for the 6,929 circuit miles and 18,310 circuit miles within each HFTD Distribution tranche. SPD similarly finds that it is improbable that the HFTD Transmission Tranche with a MARS of 1,635 has a homogenous risk profile for its 5,526 transmission circuit miles.

Staff suggests PG&E create as much granularity as reasonably possible for the TY2023 GRC to improve prioritization of mitigations and better reflect risk profiles of its system. More granular tranching of PG&E's system would allow for alternative mitigations to be better assessed for risk reduction benefits to portions of PG&E's system. Increased granularity could reveal alternative mitigations that have high mitigation effectiveness for subsets of PG&E's system. One such alternative mitigation, Rapid Earth Fault Current Limiter (REFCL), is discussed in Alternatives Analysis below. But other areas of PG&E's system, if appropriately 'tranched' may be able to be mitigated effectively with other initiatives.

Once PG&E's distribution has been divided into risk tranches sufficiently by asset categorization and then by circuits or line sections, then mitigation can be more effectively prioritized and outcomes can be assessed based on mitigations or conditions of each circuit or line section. If a circuit or line section was replaced by covered conductor and/or other wildfire mitigation measures, then the mitigation effectiveness for specific drivers (i.e. vegetation, equipment failures, animal etc.) should reflect the mitigation effectiveness on that particular circuit or line section.

Again, PG&E could use a similar approach to the large HFTD Transmission Tranche with 5,525 circuit miles. SPD recommends that PG&E further divide its Transmission assets into geographic sections, either by circuits, line sections, or even line segments for individual tranches with similar risk profiles for specific well-defined geographical areas.

And if these individual tranches are too granular for PG&E to reasonably conduct MAVF analysis, then PG&E could group circuits or line sections by similar risk profiles to make up multiple HFTD Transmission tranches. IEEE Std 100-1992 includes a definition for line segment, a subcomponent of a line section, to be a portion of a line section that has a particular type of construction or is exposed to a particular type of failure, and therefore which may be regarded as a single entity for the purpose of reporting and analyzing failure and exposure data. Hence, in the power engineering industry, transmission line segments have been analyzed by type of construction or by type of failure exposure for purposes of reporting and analyzing failure and exposure data. This power engineering data could be utilized for further wildfire risks analysis by transmission line segments.

Additionally, PG&E should also consider whether additional granularity is warranted for its substation assets, since there is a potential for mitigations to be installed at some of its substations to reduce risks for its Distribution and/or Transmission assets.

Second, SPD suggests that PG&E consider other tools, as well as data utilized to model circuit mile prioritization for 'system hardening,' vegetation management, and equipment maintenance and replacement, for insights into how tranches can be further divided into more granular homogenous risk profiles.

Third, SPD also suggests that tranches utilized in PG&E's Electric Operations Overhead Assets Risks Analysis (Chapter 11) may provide insights, particularly momentary and sustained outage data, that could be relevant to wildfire risks, particularly for assets in HFTD areas. SPD also suggests PG&E consider regions or localities of PG&E's territory, especially in HFTD areas, that could be also utilized for 'tranching' PG&E's system.

Relevant Tranche Scenario Analysis

Based on a system hardening risk prioritization analysis that PG&E had performed for its 2020 GRC based on circuit protection zones, TURN asked PG&E to break down the two highest HFTD Distribution MA Risk Scored tranches into 12 tranches, so that, in total, PG&E would have 18 tranches, instead of the 8 used in PG&E's Report.

Based on data from PG&E's 2019 GRC filing summarized in Table 10-2 below, 60 percent of the risk for the Distribution- To Be Hardened tranche is found in approximately 2,300 circuit miles (see Rows 2-7), or about 30 percent of the 6,900 miles in that tranche. In addition, the Risk Unit per Mile column shows risk is generally higher in the more granular tranches towards the top of the table, falling off considerably beginning with Row 8.

TABLE 10-2. TURN's Risk Allocation by Sub-Tranche of "Distribution – To be Hardened" and "Remainder" Circuits

Distribution - To be Hardened Tranche	Incremental Circuit Miles	Cumulative Circuit Miles	LoRE (Events/Year)	Wtd Average CoRE	Tranche Risk	Percent of Total Risk	Risk Units per Mile
2	325	325	2.3	1022.4	2,319	10%	7.14
3	434	759	2.5	956.8	2,427	10%	5.59
4	397	1,156	3.0	812.9	2,415	10%	6.09
5	395	1,551	2.6	911.3	2,355	10%	5.96
6	355	1,906	2.9	837.9	2,436	10%	6.86
7	392	2,298	3.2	741.7	2,376	10%	6.06
8	625	2,922	3.6	676.5	2,403	10%	3.85
9	616	3,538	3.8	625.7	2,380	10%	3.86
10	396	3,933	2.5	491.4	1,211	5%	3.06
11	463	4,396	2.8	431.5	1,196	5%	2.58
12	1,161	5,557	3.2	374.9	1,201	5%	1.03
13	20,038	25,595	37.7	31.7	1,197	5%	0.06
TOTALS	**25,595**		**70.0**		**23,915**	**100.0%**	0.93

Source: TURN analysis of PG&E "Dx Proritization Analysis"

TURN states that even the level of granularity reflected in Table 10-2 is not ideal because, based on PG&E's data, the LoRE and CoRE values for each circuit within each of these tranches differ. For example, TURN states PG&E undoubtedly knows that particular locations within HFTDs are more susceptible to fire weather conditions or high fuel content than other HFTD areas.

TURN opines that PG&E should also consider designing tranches based on the specific characteristics of individual equipment types that tend to increase the likelihood of occurrence of wildfires. For example, TURN states a distribution circuit includes poles, wires, transformers, reclosers, and other identifiable assets as each of these types of equipment has different failure rates and different likelihoods of causing a wildfire. TURN states these differences could be used to create separate equipment-specific tranches. TURN points out that in Chapter 11 of its RAMP filing, PG&E discusses failures of DOH assets by equipment type and has created tranches based on reliability performance. TURN believes it is reasonable to assume that some of these failures can lead to wildfires.

Observations

SPD finds that TURN's requested Tranche Scenario Analysis appears to support that more granular tranches allow PG&E to more accurately reflect the risk reduction benefits of mitigation work that is expected to be completed ***before*** the next GRC period starts in 2023 resulting in a significantly lower baseline TY2023 wildfire MA Risk Score. SPD appreciates concerns that PG&E and TURN acknowledge with the scenario analysis yet SPD finds that TURN's requested Tranche Scenario Analysis appears to make a strong case for the need for further granularity to be achieved in PG&E's wildfire risk tranching, especially in HFTD areas.

Due to SPD's findings and TURN's relevant wildfire risk tranching scenario analysis, SPD recommends that PG&E develop more granular wildfire tranches with corresponding MA Risk Scores that better reflect the LoREs and CoREs in PG&E's system, especially for HFTD areas, for PG&E's TY2023 GRC filing.

With respect to overhead powerline tranching for wildfire risk analysis, SPD recommends that PG&E develop more granular tranches for its overhead powerlines, especially that are within HFTD, through a thorough re-examination of available data and the possible application of machine learning and/or artificial intelligence (AI) data analytics techniques that could help identify more narrow risk profiles than ones that have been currently developed.

Staff recommends PG&E should also consider any insights derived from initial SME proposed initiatives to mitigate wildfire risks, which could help the utility understand how it prioritizes certain assets by common risk characteristics and which would then be classified by its own tranche. SPD also recommends PG&E consider arranging primary circuits and/or line sections into tranches according to well-defined geographic areas, such as counties, if there is enough justification to indicate a homogenous risk profile for circuits and/or line segments within each area.

Staff suggests that PG&E should aim to have no more than 500 circuit miles in tranches with the highest MA Risk Scores per circuit mile and that tranches that have relatively lower MA Risk Scores per circuit mile could have more circuit miles assuming those circuit miles within those tranches have similar risk profiles. SPD's suggestion is based on TURN's data obtained from PG&E's 2019 GRC filing to request a tranching Scenario Analysis (see Table 10-2) and observation that an estimated 60 percent of the risks were in 2,300 miles of the 6,900 Distribution To Be Hardened tranche. TURN's observation was from their tranching Scenario Analysis request where the top 80 percent of the estimated highest risk circuit miles have less than 450 circuit miles each. Tranches of this size are consistent with PG&E's RAMP proposal to progressively increase the pace of System Hardening program from 241 miles in 2020 to up to 509 miles by 2026. Hence, wildfire tranche sizes of no more than 500 circuit miles, especially for the highest risk per circuit mile tranches, should allow much better evaluation of test year and other relevant historical or proposed projects and costs.

Risk Drivers and Associated Frequencies and Associated Risks

PG&E identified six key risk drivers[28] accounting for a forecasted 443 risk events (i.e., ignitions) systemwide per year from 2023-2026 and 141 risk events in HFTD areas:

[28] PG&E also identified many sub-drivers that are not discussed in this summary.

- D1 - Equipment Failure: Systemwide: n=170 ignitions or 38 percent; HFTD: n=38 ignitions or 27 percent
- D2 – Vegetation: Systemwide: n=114 or 25 percent; HFTD: n=63 or 45 percent
- D3 – Third-Party Contact: Systemwide: n=83 or 19 percent; HFTD: n=22 or 15 percent
- D4 – Animal: Systemwide: n=55 or 12 percent; HFTD: n=13 or 10 percent
- D5 – Unknown or Other: Systemwide: n=21 or five percent; HFTD: n=5 or four percent
- D6 - Seismic Scenario (Cross-Cutting): Systemwide: n=.001 or less than one percent

Observations

The highest frequency risk driver in the bow tie analysis for systemwide assets is equipment failure at 38 percent, but in HFTD bow tie analysis, vegetation is the highest frequency risk driver at 45 percent. This illustrates the importance of the percentage of Associated Risks because for the Wildfire bow tie analysis for PG&E's entire territory, the highest frequency equipment failure risk driver is 27 percent of the associated risks while the second highest frequency risk driver, vegetation, is 44 percent of the associated risks.

In their Informal Comments, TURN identified "Failure to Assess PG&E's Operational Failures as a Driver of Wildfire Risk" as the second most significant problem with PG&E's RAMP analysis. TURN states that by excluding the driver of operational failures, PG&E's risk mitigation analysis ignores what is likely the most important mitigation of all – the Plan A of simply doing its work properly.

SPD believes that TURN raised very valid concerns about operational failures as risk drivers that are missing in PG&E's wildfire risk analysis. SPD recommends that PG&E determine an appropriate solution to model operational failures as a risk driver for its TY2023 GRC. SPD also suggests that PG&E consider the impacts of regionalization efforts on operational risks and any anticipated impacts on effective and safe operations, particularly for its complicated electrical system over a vast area of the state of California.

Cross-cutting factors

PG&E presents eight cross-cutting factors in the 2020 RAMP. Four factors were quantified in the Wildfire risk model: Climate Change; Emergency Preparedness and Response (EP&R); Records and Information Management (RIM); and Seismic.

Climate change is accounted for in PG&E's Wildfire risk model on the consequence side of the model by correlating projected future changes in PG&E territory burned with the change in frequency of ignitions that occur during RFWs. This modifies the consequences of an ignition consistent with expected climate-driven changes in the underlying factors that determine the spread and intensity of wildfire. Over time, there is an increase in the proportion of ignitions that occur during RFWs, as well as an overall increase in Wildfire risk due to climate change.

Four cross-cutting factors – seismic scenario, physical attack, skilled and qualified workforce, and records and information management – are also considered risk drivers in the risk bow tie with a collective frequency of less than 0.5 percent.

Observations

Three CCFs are especially relevant to PG&E's wildfire risk modeling for the next GRC cycle: Climate Change; Emergency Preparedness and Response (EP&R); and Records and Information Management (RIM). PG&E integrated Climate Change into its long-term wildfire risk outlook, specifically for wildfire consequences. EP&R is one of the Cross-cutting Wildfire Mitigation programs that PG&E is projecting to utilize as a Mitigation to reduce Wildfire Risk.

Consequences

For the bow tie analysis, there are 10 Outcomes modeled based on Fire Size/Destructiveness, Red Flag Warning (RFW), and Seismic factors. The fire types included are: Catastrophic; Destructive; Large or Small. The RFW is either 'Yes' or 'No'. The Seismic Event is either 'Yes', 'No'; or N/A (Non-Catastrophic outcomes). PG&E's bow tie reflects a TY2023 baseline aggregated Consequence of Risk Event (CoRE) of 57, while individual CoREs range between 0.1 and 17,094.

About 88 percent of the consequences of Wildfire Risk events are due to the small number of ignitions that result in catastrophic fires (defined as fires that burn 100 or more structures and result in a Serious Injury or Fatality). Of these, RFW Fires are 76 percent and Non-RFW Fires are 12 percent of the outcomes. Another 11 percent of the Wildfire Risks event consequences are due to RFW Destructive Fires (seven percent) and Non-RFW Destructive Fires (four percent).

PG&E states its decision to invest in PSPS, which is targeted at reducing ignitions when RFW conditions occur, aligns with mitigating its highest projected risk. PG&E states since 85 percent of wildfire risk consequences are during Red Flag Warnings, this supports PG&E's investment in Situational Awareness Mitigations, such as Improvements in Meteorology, that will improve PG&E's ability to predict and respond to conditions that have the greatest potential for ignitions to turn into more dangerous fires.

Observations

The highest frequency outcome is Non-RFW small fires at 91 percent of risk events but only 0.12 percent of projected risk outcomes for the TY2023 bow tie baseline. The second highest frequency outcome is RFW small fires at 7.8 percent but only 0.01

percent projected risk outcomes. SPD finds that since these two outcomes for small fires are almost 99 percent of risk events that PG&E should consider how to focus its MAVF analysis more heavily on conditions that support large, destructive, and catastrophic fires.

Controls and Mitigations

Per PG&E, controls are currently established measures that modify risk, such as programs required by law or policy, while mitigations are proposed measures designed to reduce one or more of the risk driver frequencies or to modify the consequence outcomes of one or more attributes.

Controls

Below is a list of Controls in the 2020-2026 RAMP (with mapping to 2017 RAMP and/or 2020 GRC):

- C1 – Patrols and inspections – Distribution Overhead (part of C1 2017),
- C2 – Patrols and inspections – Transmission Overhead (part of C1 2017),
- C3 – Patrols and inspections – Substation Overhead (part of C1 2017),
- C4 – Vegetation Management – Distribution Overhead (part of C2 2017),
- C5 – Vegetation Management – Transmission Overhead (part of C2 2017),
- C6 – Vegetation Management – Substation Overhead (part of C2 2017),
- C7 – Vegetation Management –CEMA (C3 2017),
- C8 – Equipment Maintenance & Replacement – Distribution Overhead (part of C8 2017),
- C9 – Equipment Maintenance and Replacement – Distribution Overhead (part of C8 2017),
- C10 – Equipment Maintenance and Replacement – Substation (part of C8 2017),
- C11 – Animal Abatement (C6 2017),
- C12 – Pole Programs (C9 2017),
- C13 – Transmission Structure Maintenance and Replacement,
- C14 – System Automation and Protection (C7 2017 RAMP and part of M15 2020 GRC),
- C15 – Reclose Blocking (M1 and part of M2 in 2017 RAMP and M14 2020 GRC),
- C16 – Design Standards (C11 2017),
- C17 – Restoration, Operational Procedures, and Training (C12 2017)

PG&E states recent improvements to controls include an enhanced inspection process and a new program to assess pole loading in HFTD areas.

Mitigations

PG&E's proposed wildfire mitigations include four broad strategies for understanding and responding to Wildfire risk:

1. Reduce risk through several asset management programs, including a long-term program to harden the distribution system in HFTD areas to lower ignition risk and improve fire resilience.
2. Reduce risk from the vegetation driver by significantly expanding vegetation management activities in HFTD areas beyond compliance requirements.
3. Target the highest risk wildfire conditions (days with high fire threat and high wind in HFTD areas) through the PSPS Program. PG&E recognizes that PSPS, while very effective at mitigating ignitions associated with PG&E assets, is also extremely disruptive for customers and is making significant investments to reduce the impact of future PSPS events on customers.
4. Enhance situational awareness with improvements in meteorology, high definition cameras for fire monitoring, field weather stations and satellite monitoring for better weather tracking and forecasting, and sensors in HFTD areas.

Mitigations in the 2020-2026 RAMP include the following (with mapping to 2017 RAMP and/or 2020 GRC):

- M1 – Enhanced vegetation management (EVM) (M16 2020 GRC),
- M2 – System hardening (M12 2020 GRC),
- M3 – Non-exempt surge arrester replacement (M5 2017 RAMP),
- M4 – Expulsion fuse replacement (C4 2017),
- M5 – PSPS (M13 2020 GRC),
- M6 – PSPS Impact Reduction Initiatives (includes 2020 GRC M10 & M15) (Foundational[29]),
- M7 – Situational Awareness and Forecasting Initiatives (includes 2020 GRC M18, M19, M20, M21, M23 & M24) (Foundational),
- M8 – Safety and Infrastructure Protection Teams (SIPT) (M25 2020 GRC) (Foundational),
- M9 – CWSP PMO (M28 2020 GRC) (Foundational),
- M10 – Additional System Automation and Protection (Foundational), and
- M11 – Remote grid (implemented for the ’20-22 Mitigation Plan)

TABLE 10-3. Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026

Program	Expense ($000s)	Capital ($000s)	Risk Score Reduction	Risk Spend Efficiency
M1-EVM	2,211,877		4,156	2.6
M2-Harden		3,400,802	17,893	7.3

[29] Foundational Mitigations are programs that support other mitigations that reduce Wildfire risk, but do not reduce the risk themselves. Hence, PG&E considers them foundational and does **not** calculate a risk reduction or RSE.

Program	Expense ($000s)	Capital ($000s)	Risk Score Reduction	Risk Spend Efficiency
M4-Fuse Repl.		24,711	18	1.0
M5-PSPS	763,334		16,284	13.8
M6-PSPS Impact Reduction	522,243		Combined w/M5	Combined w/M5

The PSPS and System Hardening mitigation programs have the highest RSE scores and the highest total risk reduction scores. The RSE score for PSPS includes the cost of programs that PG&E is undertaking to reduce the impact of PSPS on customers by reducing the PSPS footprint and shortening restoration times.

Observations

PG&E only calculated RSEs for six non-foundational wildfire mitigations and for cross-cutting mitigation programs which can be most easily observed in PG&E's 'waterfall' risk reduction overview graph along with the associated 2020-2026 wildfire mitigation risk reduction table. Of these seven mitigation programs, PSPS has the highest associated risk reduction score for every individual year between 2020-2026 compared to any other mitigation risk reduction, including System Hardening. Specifically, PSPS was calculated to reduce wildfire risks by between 5,649-5,972 for years 2020-2026, respectively. Meanwhile, System Hardening (M2), was calculated to reduce wildfire risks by 105-1,394 for years 2020-2026, respectively. It is also noteworthy that cross-cutting mitigation programs are shown to reduce wildfire risks by 189-920 between 2020-2026, respectively. In comparison, the only other wildfire mitigation that is shown to reduce substantive risks is Enhanced Vegetation Management (EVM) (M1) by 50-228 between 2020-2026, respectively. SPD provides observations for select Mitigations and Controls below.

SPD finds that several critical wildfire controls and mitigations could be more disaggregated for Risk Reduction and corresponding RSE analysis. SPD recommends PG&E include more individual initiatives for RSE analysis to understand the effectiveness and efficiency of each specific mitigation. SPD discusses select mitigation observations below and suggests similar findings may apply to Controls.

SPD finds that all controls and all foundational mitigations lack RSE modeling and the results to support controls/foundational mitigations as continuing mitigations and/or to provide insight into effectiveness to reduce wildfire risks. SPD also reiterates WSD-002 Deficiency (Guidance-5, Class B) which found that aggregation of wildfire initiatives into programs creates the challenge that ineffective elements of broad programs cannot be determined and future considerations of initiatives within programs can only be analyzed collectively.

M5 PSPS

PG&E lists PSPS as a mitigation tool (M5), despite PSPS being intended as a tool of last resort and the action of shutting off electric utility service for public safety (i.e. Public Safety Power Shutoff) inherently being a measure with its own risks to PG&E's customers, risks that PG&E implicitly acknowledges with the inclusion of M6.

SPD initially identified PG&E's use of PSPS as a mitigation justified by RSE as a Wildfire Safety Division (WSD) compliance deficiency on July 28, 2020. [30] SPD referenced WSD-002 and WSD-003 Resolutions issued on June 11, 2020. Specifically, WSD-002 states "RSE is not an appropriate tool for justifying the use of PSPS. When calculating RSE for PSPS, electrical corporations generally assume 100 percent wildfire risk mitigation and very low implementation costs because societal costs and impact are not included. When calculated this way, PSPS will always rise to the top as a wildfire mitigation tool, but it will always fail to account for the true costs to customers. Therefore, electrical corporations shall not rely on RSE calculations as a tool to justify the use of PSPS.".[31]

Therefore, SPD requested PG&E conduct a Scenario Analysis removing PSPS as a Mitigation in the Wildfire Mitigation Portfolio.[32] To comply with SPD's PSPS Removal Scenario Analysis request, PG&E stated they would also need to remove M6 PSPS Impact Reduction Initiative since it was dependent on M5.

PG&E submitted both workpapers and a PowerPoint presentation dated October 2, 2020 entitled "WF Scenario Analysis Results – Without PSPS in the Portfolio" with associated new calculated RSEs and 'waterfall' graphs. Risk Reduction with PSPS using PG&E's MAVF is shown as a reference in slide three, copied into Table 10XA, including PG&E's associated waterfall graph with the July 17, 2020 errata reflected in the relevant program risk reductions. Then PG&E presents its Risk Reduction without PSPS using PG&E's MAVF in slide four, copied into FIGURE 10-1 on the following page.

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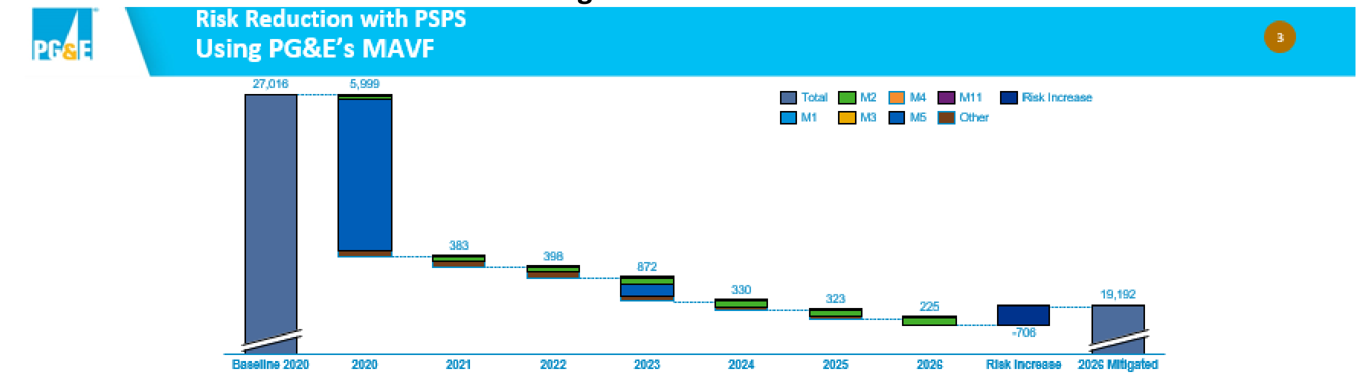
[30] On 7/29/2020, SPD issued an agenda item, dated 7/28/2020, for the July 30th PG&E RAMP Wildfire Risk Mitigation Plan Workshop which included initial SPD identified deficiencies.

[31] WSD-002 pg. 20.

[32] SPD additionally requested PG&E to run a 2nd similar scenario analysis with all Attributes (i.e. Safety, Electric Reliability & Financial) to use Linear and Uncapped functions for the modeling. TURN requested a similar Scenario Analysis but with the adjustment to only modify the Safety & Financial the Electric Reliability attribute functions to be Linear & Uncapped. This report does not address the 2nd SPD Scenario nor TURN's Scenario Analysis although these scenarios may still provide useful information for PG&E to consider for its TY2023 GRC.

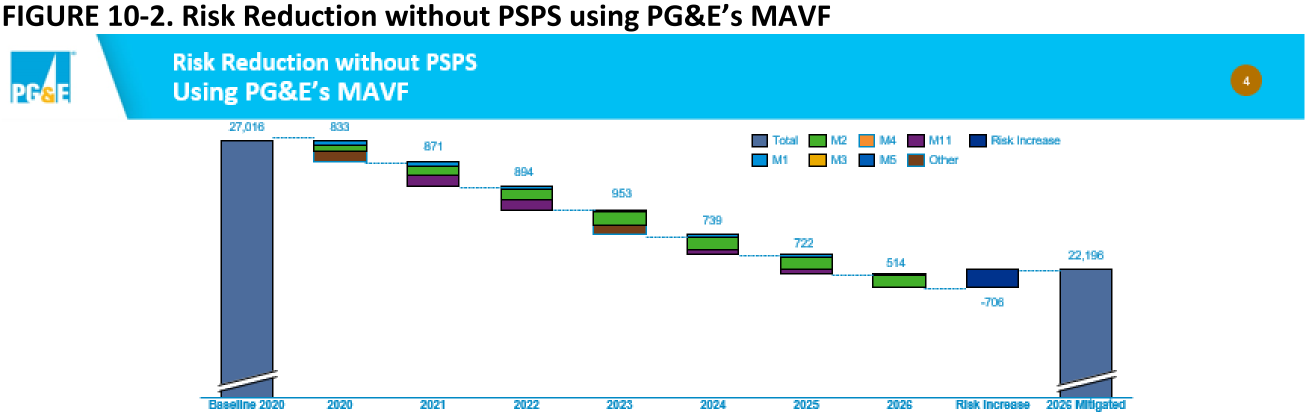
FIGURE 10-1. Risk Reduction with PSPS using PG&E's MAVF



#	Mitigation Programs[1]	2020	2021	2022	2023	2024	2025	2026
M1	Enhanced Vegetation Management	50	81	114	141	168	196	228
M2	System Hardening	105	276	477	700	931	1161	1394
M3	Non-Exempt Surge Arrester Replacement Program	5	13	14	14	14	14	14
M4	Expulsion Fuse Replacement	0	0	0	1	1	1	1
M5	Public Safety Power Shutoff[2]	5649	5634	5615	6046	6024	5996	5972
M11	Remote Grid	1	1	1	1	1	1	1
Other	Cross-cutting mitigation programs	189	376	559	750	844	936	920
	Risk Increase due to Climate Factors in Baseline	0	0	0	-706	-706	-706	-706
	Total	5999	6382	6780	6946	7276	7599	7824

(1) Excludes Foundational Mitigations.
(2) Includes PSPS's Reliability Impact as reducing overall risk reduction.
(3) Risk reduction by program reflects July 17th errata.

FIGURE 10-2. Risk Reduction without PSPS using PG&E's MAVF



#	Mitigation Programs[1]	2020	2021	2022	2023	2024	2025	2026
M1	Enhanced Vegetation Management	204	329	451	559	653	746	842
M2	System Hardening	215	563	963	1418	1875	2325	2775
M3	Non-Exempt Surge Arrester Replacement Program	15	28	29	29	29	29	28
M4	Expulsion Fuse Replacement	1	1	2	2	3	3	3
M5	Public Safety Power Shutoff[2]	0	0	0	0	0	0	0
M11	Remote Grid	2	2	2	2	2	2	2
Other	Cross-cutting mitigation programs	396	780	1152	1541	1727	1907	1874
	Risk Increase due to Climate Factors in Baseline	0	0	0	-706	-706	-706	-706
	Total	833	1704	2598	2845	3584	4305	4820

(1) Excludes Foundational Mitigations.
(2) Includes PSPS's Reliability Impact as reducing overall risk reduction.
(3) Risk reduction by program reflects July 17th errata.

Comparing the percentage MA Risk Reduction Scores for the top wildfire risk reduction programs without versus with PSPS demonstrates one of the problems of including PSPS as a Mitigation, particularly at a system-wide level. SPD calculated these percentages and has included them in Table 10-4 below.

TABLE 10-4.[33] Comparison of MA Risk Reduction Scores with PSPS and without PSPS

SPD Calculations of Associated % of Total Annual Risk Reductions for each Mitigation Annually																
PG&E RAMP Wildfire Mitigation Portfolio with PSPS (Slide 3) for Baseline Comparison																
		PG&E RAMP MA Risk Reduction Scores								**Associated % of Total Annual Risk Reductions**						
		2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
M1	**EVM**	50	81	114	141	168	196	228		1%	1%	2%	2%	2%	3%	3%
M2	**System Hardening**	105	276	477	700	931	1161	1394		2%	4%	7%	10%	13%	15%	18%
M3	**Non-Exempt Surge Arrestor**	5	13	14	14	14	14	14		0%	0%	0%	0%	0%	0%	0%
M4	**Expulsion Fuse**	0	0	0	1	1	1	1		0%	0%	0%	0%	0%	0%	0%
M5	**PSPS**	5649	5634	5615	6046	6024	5996	5972		**94%**	**88%**	**83%**	**87%**	**83%**	**79%**	**76%**
M11	**Remote Grid**	1	1	1	1	1	1	1		0%	0%	0%	0%	0%	0%	0%
	Cross Cutting Mitigations	189	376	559	750	844	936	920		3%	6%	8%	11%	12%	12%	12%
	Risk Increase due to CC	0	0	0	-706	-706	-706	-706		0%	0%	0%	-10%	-10%	-9%	-9%
Total Annual Risk Reduction		**5999**	**6381**	**6780**	**6947**	**7277**	**7599**	**7824**		100%	100%	100%	100%	100%	100%	100%
PG&E's Results for SPD WITHOUT PSPS Scenario Analysis in the Wildfire Mitigation Portfolio from 10/2/2020 Slide 4																
		Revised PG&E Risk Reduction Scores								**Associated % of Total Annual Risk Reductions**						
		2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
M1	**EVM**	204	329	451	559	653	746	842		24%	19%	17%	20%	18%	17%	17%
M2	**System Hardening**	215	563	963	1418	1875	2325	2775		26%	33%	37%	50%	52%	54%	58%
M3	**Non-Exempt Surge Arrestor**	15	28	29	29	29	29	28		2%	2%	1%	1%	1%	1%	1%
M4	**Expulsion Fuse**	1	1	2	2	3	3	3		0%	0%	0%	0%	0%	0%	0%
M5	**PSPS**	0	0	0	0	0	0	0		0%	0%	0%	0%	0%	0%	0%
M11	**Remote Grid**	2	2	2	2	2	2	2		0%	0%	0%	0%	0%	0%	0%
	Cross Cutting Mitigations	396	780	1152	1541	1727	1907	1874		48%	46%	44%	54%	48%	44%	39%
	Risk Increase due to CC	0	0	0	-706	-706	-706	-706		0%	0%	0%	-25%	-20%	-16%	-15%
Total Annual Risk Reduction		**833**	**1703**	**2599**	**2845**	**3583**	**4306**	**4818**		100%	100%	100%	100%	100%	100%	100%

As can be seen from SPD Table 10XC, the removal of PSPS as a Mitigation is not as simple as subtracting the MA Risk Reduction Scores associated with PSPS annually since new MA Risk Reduction Scores are computed for the non-PSPS Mitigations. In the SPD requested WITHOUT PSPS Scenario Analysis, the top three system-wide wildfire mitigations in order of highest MA Risk Reduction Scores are (1) Cross Cutting Mitigations; (2) System Hardening; and (3) Enhanced Vegetation Management (EVM).

In Years 2020-2022 and in Year 2023, the highest risk reducing mitigation is the cross-cutting mitigations with RSEs equivalent to 396-1152 in Years 2020-2022 and RSE of 1541 in Year 2023. Comparatively, System Hardening is the second highest risk reducing mitigation with RSEs of 215-963 in Years 2020-2022 and RSE of 1418 in Year 2023.

[33] Rounding of whole MA Risk Reduction Scores slightly impacted some of the Total Annual Risk Reduction Scores.

Additionally, EVM is consistently the third highest risk reducing mitigation with RSEs of 204-451 in Years 2020-2022 and RSE of 559 in Year 2023.

For PG&E's Scenario Analysis WITHOUT PSPS, Cross Cutting (CC) Mitigations make up 44-48 percent in 2020-2022 and 54 percent in 2023 of the total annual wildfire MA Risk Reduction Scores. In comparison, System Hardening Mitigation makes up 26-37 percent in 2020-2022 and 50 percent in 2023 of total annual wildfire MA Risk Reduction Scores. Additionally, EVM makes up 17-24 percent in 2020-2022 and 20 percent in 2023 of the total annual wildfire MA Risk Reduction Scores.

SPD also finds it is important to note that in TY2023, the Scenario Analysis WITHOUT PSPS includes 25 percent MA Risk Score increase due to Climate Change. SPD finds the Scenario Analysis WITHOUT PSPS allows for an important refinement to be able to begin to evaluate not only non-PSPS Mitigations risk reduction benefits but also impacts of PG&E's assumptions related to wildfire risk increases for the entire 2023-2026 GRC cycle. SPD finds that the impacts and relationships between Cross Cutting Mitigations, System Hardening, EVM, and Increased Climate Change Risk are more difficult to analyze when PSPS is included in the Wildfire Mitigation Portfolio as seen with the second half of Table 10-4.

SPD therefore recommends that PSPS be removed as a mitigation for the TY2023 GRC filing and that if desired, PG&E address PSPS impacts to wildfire MAVF risk analysis in other ways. SPD's recommendation to remove PSPS as a mitigation is in no way intended to discourage PG&E from utilizing PSPS to protect public safety as a measure of last resort and as allowed by the Commission in D.19-05-042. SPD's finding is both a result of WSD's identified deficiency that "RSE is not an appropriate tool for justifying the use of PSPS"[34] and SPD's observations stated above. Finally, SPD suggests PG&E consider alternative methodologies to analyze PSPS in its wildfire risk analysis for PG&E's TY2023 GRC filing.

M2 System Hardening

In SPD's initial deficiencies[35], M2 System Hardening (SH) was provided as an example of a mitigation that was insufficient because it aggregated many separate mitigations. SPD recommends that M2 be divided into individual initiatives, especially for large non-related capital initiatives. Currently, PG&E combined the largest two SH programs, Covered Conductor and Undergrounding, into SH mitigation and calculated one RSE for the System Hardening Mitigation.

Additionally, PG&E included Pole Replacements, Fuse/Cutouts & Switch Replacements with CALFIRE Certified Low Risk Equipment and Transformer Replacements with Fire

[34] WSD-002 pg 20.

[35] On 7/29/2020, SPD issued an agenda item, dated 7/28/2020, for the July 30th PG&E RAMP Wildfire Risk Mitigation Plan Workshop which included initial SPD identified deficiencies.

Resistant FR3 Insulation Fluid into M2 System Hardening. SPD suggests only programs that are directly related to Covered Conductor or Undergrounding should be included in Risk Reduction and RSE calculations for these individual SH programs. Other initiatives that are not required as part of Covered Conductor or Undergrounding should be separated into unique Mitigations with their own Risk Reduction and RSE calculations similar to PG&E's current M3 Non-Exempt Surge Arrestor Replacement Program and M4 Expulsion Fuse Replacement Program.

SPD recommends that PGE& provide MA Risk Reduction Scores, costs, and RSEs for individual initiatives, as much as reasonably possible. Additionally, SPD recommends that PG&E provide appropriate mitigations associated with other SPD observations, findings, and recommendations for its wildfire MAVF model changes in its TY2023 GRC.

Controls

SPD also recommends PG&E provide RSE calculations or estimates for its controls. While the Settlement Agreement lexicon does adopt definitions that distinguish between "controls" and "mitigations," it remains important to have information on the effectiveness of controls, both to (1) gauge the relative efficiency of proposed mitigation and (2) to provide information to help understand the cost-effectiveness of the risk reduction measures already in place.

Wildfire Cross Cutting Mitigation Programs

PG&E also includes Cross Cutting Mitigation Programs as another Mitigation for Wildfire risks. PG&E calculated risk reductions from these CC Mitigation Programs in their original filing with PSPS as a Mitigation starting at 189 in 2020, 376 in 2021, 559 in 2022, 750 in 2023, 844 in 2024, 936 in 2025 and 920 in 2026.

PG&E's CCF bow tie in Chapter 20 shows that approximately three-fourths of the CCF Mitigation risk reduction is attributed to Emergency Operations Center (EOC) Enhancements with the second largest reduction in risks attributed to Mutual Aid Enhancements at approximately 20 percent. PG&E informed SPD that Mutual Aid is not always called for in catastrophic events which is why the risk reduction is not as high as EOC Enhancements. PG&E also explained that EOC Enhancements will benefit PG&E for non-wildfire events such as elections, storm season, gas events or other major electric events. Still, wildfire mitigation does have a large benefit due to the size of the risk. It is unclear why cross cutting mitigation risk reduction benefits are not higher in 2020 or 2021 compared to later years. SPD recommends that PG&E reassess how CCF Mitigation will reduce risk year by year especially if they are not capital projects with longer implementation timelines.

Mitigations should be such that proposed programs and/or projects are able to be identified as effective mitigations for specific assets or subsystems, such as 12.5-kV or 17-kV 3-wire distribution circuits.

FERC Transmission Mitigations

SPD also recommends PG&E provide information on certain wildfire safety mitigation work in FERC proceedings in their GRC filing. On June 1, 2020, PG&E separately identified in their FERC Stakeholder Transmission Asset Review (STAR) process their transmission asset strategy with their current five-year investment plan and prioritization procedures. In their STAR June 1, 2020 Project Data Spreadsheet, in addition to projects in HFTD areas, PG&E identified 150 transmission projects from 2018 through 2025 in CPUC Tier 1 non-HFTD area for the purposes of wildfire risk mitigation, including seven and 24 specifically identified as projects to be completed in 2020 and 2021-2025, respectively.[36] SPD recommends that PG&E include this project information and clearly explain its wildfire risk analysis justifying work in non-HFTD and HFTD areas for its transmission assets in its RAMP update in its upcoming TY 2023 GRC filing, even if funding for transmission assets are requested in FERC proceedings. Another reason the risk assessment and analysis for transmission wildfire risks should be filed in the upcoming TY 2023 GRC is to examine whether the MAVF risk analysis is consistent with the risk assessment and analysis for distribution wildfire risks.

Alternatives Analysis

One alternative, A3, provided by PG&E does not replace its existing base wire but focuses on system modifications to reduce the potential for outages that could result in ignitions. Another alternative PG&E provided is a package of system modifications that falls somewhere between the existing M2 System Hardening and the A3 alternative.

SPD Suggested Alternative: Rapid Earth Fault Current Limiter (REFCL)

PG&E should include in its mitigations or alternatives analysis the use of new technologies for wildfire mitigations such as Rapid Earth Fault Current Limiter (REFCL). REFCL is a relatively new technology that significantly reduces wildfire risks by electrical single line to ground faults. This technology was recently implemented in Australia (State of Victoria) to mitigate wildfire risks with most of the equipment installation occurring at the substation. This is significant since this wildfire mitigation does not require replacement of overhead powerlines.

PG&E plans to complete the installation of REFCL on two circuits in substations in Calistoga. This mitigation tool reduces the potential for ignition by significantly lowering the energy for single line-to-ground faults and partially lowering the energy of line-to-line-to-ground faults.[37]

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[36] Stakeholder Transmission Asset Review (STAR) Process set forth in PG&E's Offer of Partial Settlement in the TO20 rate case proceeding (Docket No. ER19-13-001). To access an electronic version, please follow the below instructions: 1) Search for Public Case Documents: https://pgera.azurewebsites.net/Regulation/search; 2) Select "Stakeholder Transmission Asset Review (STAR) []" from the Case dropdown menu; 3) Select "PGE" from the Party dropdown menu; 4) Input the date from "06/01/20" to "06/01/20"; 5) Click Search

[37] REFCL overcurrent protection de-energizes to ½ Amp within 80ms as required by state of Victoria.

SPD requested that PG&E conduct an REFCL Scenario Analysis based on best available information and SME input. Hence, in an October 21, 2020 scenario analysis provided by PG&E, the utility explored the use of REFCL as a mitigation tool. RSE Analysis of the REFCL Program is targeted at 12kV and 17kV DOH lines in Tiers 2 and 3 HFTD areas. At a cost of $12 million and a risk reduction score of 1,511 for 160 circuit miles, the RSE of 126 is by far the highest of all wildfire mitigations. RECFL technology has shown a 58 percent mitigation overall effectiveness and a 92 percent effectiveness for line-to-ground faults. PG&E informed SPD that there is potential for utilizing RECFL for 5,700 miles in Tier 3 and 16,000 circuit miles in Tier 2. SPD finds that REFCL technology could be groundbreaking for PG&E as a wildfire mitigation especially if REFCL could substantively reduce wildfire risks for up to 85 percent of PG&E's HFTD Distribution overhead power lines.

A combination of covered conductor and REFCL would substantially reduce ignition risks. A PG&E SME informed SPD that the one limiting factor is resource constraints due to the limited production of ground fault neutralizer and capacitor balancing units, which are REFCL critical components. SPD suggests PG&E consider ways to prioritize R&D efforts in REFCL and related technologies to expeditiously reduce wildfire risks with more cost-effective technical solutions.

Finally, it is noteworthy that REFCL technology can only be utilized for three-phase, three-wire medium voltage primary circuits or feeders. Interestingly, these systems are not widely used for public distribution, except in California.[38]

SPD recommends that PG&E alternatives and alternatives such as REFCL, Early Fault Detection, and other capital and O&M alternatives be considered for individual, more granular tranches with associated RSE calculated in order to compare many alternatives for each tranche. This could support decision-making that better targets cost-effective wildfire risk mitigation investments.

Summary of Findings

Risk Description

SPD finds wildfire risks are appropriately the top safety risk for PG&E's 2020 RAMP Report and TY2023 GRC.

Bow tie

SPD finds that the overall MARS ranking appears appropriate due to the known fact that wildfire is currently, and for the foreseeable future, PG&E's top safety risk.

[38] Standard Handbook for Electrical Engineers, 13th Edition, Donald G. Fink / H. Wayne Beaty, pg 18-6.

SPD finds that wildfire bow tie risk analysis using the entire service territory for its exposure allows for MARS to be heavily allocated to PG&E's HFTD wildfire risk tranches.

Tranches

Two HFTD Distribution tranches, with about 25,000 circuit miles, account for more than 92 percent of the total wildfire MARS. Additionally, the HFTD Transmission Tranche, with more than 5,500 circuit miles, accounts for 6.5 percent of the total wildfire MA Risk Score. These three HFTD tranches with 98.93 percent of the total wildfire MA Risk Score are more than 30,000 circuit miles or more than percent of PG&E's total overhead Distribution and Transmission circuit miles. The S-MAP Settlement Agreement (SA) requires PG&E to "strive to achieve as deep a level of granularity as reasonably possible."[39] In consideration of PG&E's RAMP filing, extensive discussions in RAMP Workshops and Scenario Analysis informal workshops in September and October 2020, and Intervenor informal comments, SPD finds that PG&E should provide as much granularity as reasonably possible as required by the S-MAP Settlement Agreement particularly for the three highest risk scored HFTD wildfire risk tranches for the TY2023 GRC filing.

The Settlement Agreement requires PG&E to subdivide its group of assets or its system into Tranches to demonstrate how mitigations will reduce wildfire risks. PG&E is required to base the determination of Tranches on how the wildfire risks and assets are managed by the utility, data availability and model maturity, and strive to achieve as deep a level of granularity as reasonably possible.

SPD finds that it is highly unlikely that the two non-Hardened HFTD Distribution tranches– with MA Risk scores of 11,411 and 11,811, respectively – have homogenous risk profiles for the 6,929 circuit miles and 18,310 circuit miles within each HFTD Distribution tranche. SPD similarly finds that it is improbable that the HFTD Transmission Tranche with a MA Risk Score of 1,635 has a homogenous risk profile for its 5,526 transmission circuit miles.

SPD finds that TURN's requested Tranche Scenario Analysis appears to support that more granular tranches allow PG&E to more accurately reflect the risk reduction benefits of mitigation work that is expected to be completed ***before*** the next GRC period starts in 2023, resulting in a significantly lower baseline TY2023 wildfire MA Risk Score. SPD appreciates concerns that PG&E and TURN acknowledge with the scenario analysis yet SPD finds that TURN's requested Tranche Scenario Analysis appears to makes a strong case for the need for further granularity to be achieved in PG&E's wildfire risk 'tranching', especially in HFTD areas.

[39] Decision 18-12-015 Attachment A, S-MAP Settlement Agreement, Row 14, pg. A-11.

Risk Drivers and Associated Frequencies and Associated Risks

The highest frequency risk driver in the bow tie analysis for systemwide assets is equipment failure at 38 percent, but in HFTD bow tie analysis, vegetation is the highest frequency risk driver at 45 percent. This exemplifies the importance of the percentage of Associated Risks because for the Wildfire bow tie analysis for PG&E's entire territory, the highest frequency equipment failure risk driver is 27 percent of the associated risks while the second highest frequency risk driver, vegetation, is 44 percent of the associated risks.

Cross-cutting factors

Three cross-cutting factors are especially relevant to PG&E's wildfire risk modeling for the next GRC cycle: Climate Change; Emergency Preparedness and Response (EP&R); and Records and Information Management (RIM). PG&E integrated Climate Change into its long-term wildfire risk outlook, specifically for wildfire consequences. EP&R is one of the Cross-cutting Wildfire Mitigation programs that PG&E is projecting to utilize as a Mitigation to reduce Wildfire Risk.

*Consequences*The highest frequency outcome is Non-RFW small fires at 91 percent of risk events but only 0.12 percent of projected risk outcomes for the TY2023 bow tie baseline. The second highest frequency outcome is RFW small fires at 7.8 percent but only 0.01 percent projected risk outcomes. SPD finds that since these two outcomes for small fires are almost 99 percent of risk events. Hence, PG&E should consider how to focus its MAVF analysis more heavily on conditions that support large, destructive, and catastrophic fires.

Controls and Mitigations

PG&E only calculated RSEs for six non-foundational wildfire mitigations and for cross-cutting mitigation programs which can be most easily observed in PG&E's 'waterfall' risk reduction overview graph along with the associated 2020-2026 wildfire mitigation risk reduction table. Of these seven mitigation programs, PSPS has the highest associated risk reduction score for every individual year between 2020-2026 compared to any other mitigation risk reduction, including System Hardening. Specifically, PSPS was calculated to reduce wildfire risks by between 5,649-5,972 for years 2020-2026, respectively. System Hardening (M2), was calculated to reduce wildfire risks by 105-1,394 for years 2020-2026, respectively. It is also noteworthy that cross-cutting mitigation programs are shown to reduce wildfire risks by 189-920 between 2020-2026, respectively. In comparison, the only other wildfire mitigation that is shown to reduce substantive risks is Enhanced Vegetation Management (EVM) (M1) by 50-228 between 2020-2026, respectively. SPD provides observations for select Mitigations and Controls below.

SPD finds that several critical wildfire controls and mitigations could be more disaggregated for Risk Reduction and corresponding RSE analysis.

SPD finds that all controls and all foundational mitigations lack RSE modeling and the results to support controls/foundational mitigations as continuing mitigations and/or to provide insight into effectiveness to reduce wildfire risks. SPD also reiterates WSD-002 Deficiency (Guidance-5, Class B) which found that aggregation of wildfire initiatives into programs creates the challenge that ineffective elements of broad programs cannot be determined and future considerations of initiatives within programs can only be analyzed collectively.

Mitigation M5 PSPS

The removal of PSPS as a Mitigation is not as simple as subtracting the MA Risk Reduction Scores associated with PSPS annually since new MA Risk Reduction Scores are computed for the non-PSPS Mitigations. In the SPD-requested WITHOUT PSPS Scenario Analysis, the top three system-wide wildfire mitigations in order of highest MA Risk Reduction Scores are (1) Cross Cutting Mitigations; (2) System Hardening; and (3) Enhanced Vegetation Management (EVM).

In Years 2020-2022 and in Year 2023, the highest risk-reducing mitigation is the cross-cutting mitigations with RSEs equivalent to 396-1152 in Years 2020-2022 and RSE of 1541 in Year 2023. System Hardening is the second highest risk reducing mitigation with RSEs of 215-963 in Years 2020-2022 and RSE of 1418 in Year 2023. EVM is consistently the third highest risk reducing mitigation with RSEs of 204-451 in Years 2020-2022 and RSE of 559 in Year 2023.

For PG&E's Scenario Analysis WITHOUT PSPS, Cross Cutting (CC) Mitigations make up 44-48 percent in 2020-2022 and 54 percent in 2023 of the total annual wildfire MA Risk Reduction Scores. System Hardening Mitigation makes up 26-37 percent in 2020-2022 and 50 percent in 2023 of total annual wildfire MA Risk Reduction Scores. EVM makes up 17-24 percent in 2020-2022and 20 percent in 2023 of total annual wildfire MA Risk Reduction Scores.

SPD also finds it important to note that in TY2023, the Scenario Analysis WITHOUT PSPS includes 25 percent MA Risk Score increase due to Climate Change. SPD finds that the Scenario Analysis WITHOUT PSPS allows for an important refinement to be able to begin to evaluate not only non-PSPS Mitigations risk reduction benefits but also impacts of PG&E's assumptions related to wildfire risk increases for the entire 2023-2026 GRC cycle. SPD finds that the impacts and relationships between Cross Cutting Mitigations, System Hardening, EVM and Increased Climate Change Risk are more difficult to analyze when PSPS is included in the Wildfire Mitigation Portfolio.

Mitigation M2 System Hardening

In SPD's initial deficiencies list[40], M2 System Hardening (SH) was provided as an example of a mitigation that was insufficiently analyzed because it aggregated many separate mitigations. PG&E combined the largest two SH programs, Covered Conductor and Undergrounding, into SH mitigation and calculated one RSE for the System Hardening Mitigation. Additionally, PG&E included Pole Replacements, Fuse/Cutouts & Switch Replacements, CalFIRE Certified Low Risk Equipment and Transformer Replacements with Fire Resistant FR3 Insulation Fluid into M2 System Hardening.

Wildfire Cross Cutting Mitigation Programs

PG&E's CCF bow tie in Chapter 20 shows that approximately three-fourths of the CCF Mitigation risk reduction is attributed to Emergency Operations Center (EOC) Enhancements, with the second largest reduction in risks attributed to Mutual Aid Enhancements at approximately 20 percent. PG&E informed SPD that Mutual Aid is not always called for catastrophic events which is why the risk reduction is not as high as for the EOC Enhancements. PG&E also explained that EOC Enhancements will benefit PG&E for non-wildfire events such as Election Day, storm season, gas events, or other major electric events. Yet wildfire mitigation does have a large benefit from the cross-cutting mitigations due to the size of the risk. It is unclear why cross-cutting mitigation risk reduction benefits are not higher in 2020 or 2021 compared to later years.

SPD finds that REFCL technology is suitable to many of PG&E's operations, has shown demonstrated effectiveness in Australia, and is being studied by PG&E on an R&D basis with the potential to be proposed for the 2023-2026 GRC cycle.

Recommended Solutions to Address Findings and Deficiencies

Wildfire Risk Bow tie

Since 99.5 percent of the Wildfire risk is in their HFTD areas, PG&E must ensure that MAVF modeling capabilities are fully utilized to sufficiently focus risk analysis on these areas.

Wildfire Risk Tranches

SPD recommends that PG&E create as much granularity as reasonably possible for the TY2023 GRC in order for MA Risk Scores to reflect risk profiles of its system more appropriately. SPD believes that more granular tranching of PG&E's system, perhaps to have no more than 100-500 circuit miles in each tranche, would allow for mitigations to be better assessed for risk reduction benefits.

[40] On 7/29/2020, SPD issued an agenda item, dated 7/28/2020, for the July 30th PG&E RAMP Wildfire Risk Mitigation Plan Workshop which included initial SPD identified deficiencies.

PG&E should consider dividing its electric distribution assets into smaller tranches for risk analysis. For PG&E's distribution system, assets can be first divided into tranches by classifications, such as a group for all 12.47 kV overhead lines and assets. PG&E has already done this by identifying only circuit miles that are overhead power lines as exposed to wildfire and excluding underground power lines. Additionally, PG&E should consider dividing their assets by system voltage and perhaps by scheme of connection (i.e. radial, loop, network, multiple or series) and number of conductors (2-wire, 3-wire, 4-wire, etc).[41] PG&E should also consider dividing their assets by load types (residential, commercial, street lighting, railways, etc.) in instances where this could help further tranche assets.

SPD recommends that PG&E consider how to model the three highest Multi-Attribute Risk Score tranches with more granularity and specifically with fewer circuit miles in each tranche for the TY2023 GRC.

PG&E should consider other tools, as well as data utilized to model circuit mile prioritization for system hardening, vegetation management, and equipment maintenance and replacement, for insights into how tranches can be further divided into more granular homogenous risk profiles.

SPD also suggests that tranches identified in PG&E's Electric Operations Overhead Assets Risks Analysis (Chapter 11), particularly those grouped by momentary and sustained outage data, may provide insights that could be relevant to wildfire risks, especially for assets in HFTD areas. And SPD recommends that PG&E consider geographic sections, regions or localities of PG&E's territory, especially in HFTD areas, that could further develop tranche groupings.

HFTD Distribution overhead circuit lines could be tranched by types of primary circuits or line sections if the risk profiles of the feeder(s) and/or circuit segment(s) is deemed to be homogenous. If the feeder is deemed to have varying degrees of risk profiles, then a feeder (i.e. asset) could be divided into its line sections for allocating its sections to appropriate individual tranches. Alternatively, PG&E could consider tranching circuits by groups of 'zones of protection' rather than line sections if there is a definitive clear endpoint for each zone.

Once PG&E's distribution has been divided into risk tranches sufficiently by asset categorization and then by circuits or line sections, then outcomes can be assessed based on mitigations or conditions of each circuit or line section. If a circuit or line section was replaced by covered conductor and/or other wildfire mitigation measures, then the mitigation effectiveness for specific drivers (i.e. vegetation, equipment failures, animal etc.) should reflect the mitigation effectiveness on that particular circuit or line section.

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[41] Standard Handbook for Electrical Engineers, 13th Edition, Donald G. Fink / H. Wayne Beaty, p 18-5.

Again, PG&E could use a similar approach to the large HFTD Transmission Tranche with 5,525 circuit miles. SPD recommends that PG&E further divide its Transmission assets into geographic sections, either by circuits, line sections, or even line segments for individual tranches with similar risk profiles for specific well-defined geographical areas. And if these individual tranches are too granular for PG&E to reasonably conduct MAVF analysis, then PG&E could group circuits or line sections by similar risk profiles to make up multiple HFTD Transmission tranches.

Additionally, PG&E should consider whether additional granularity is warranted for its substation assets, since there is a potential for mitigations to be installed at some of its substations to reduce risks for its Distribution and/or Transmission assets.

SPD recommends that PG&E use machine learning and/or artificial intelligence (AI) data analytics techniques to identify more narrow and homogenous risk profiles. PG&E should also consider insights derived from SME proposed initiatives to mitigate wildfire risks, which could help the utility understand how it prioritizes certain assets by common risk characteristics and which would then be classified by its own tranche.

Risk Drivers and Associated Frequencies and Associated Risks

SPD recommends that PG&E determine an appropriate solution to model operational failures as a risk driver for its TY2023 GRC. SPD also suggests that PG&E consider the impacts of regionalization efforts on operational risks and any anticipated impacts on effective and safe operations, particularly for its complicated electrical system over a vast area of the state of California.

Mitigation M5 PSPS

SPD recommends that PSPS be removed as a mitigation for the TY2023 GRC filing and that if desired, PG&E address PSPS impacts to wildfire MAVF risk analysis in other ways. SPD's recommendation to remove PSPS as a mitigation is in no way intended to discourage PG&E from utilizing PSPS to protect public safety as a measure of last resort and as allowed by the Commission in D.19-05-042. SPD's finding is both a result of WSD's identified deficiency that 'RSE is not an appropriate tool for justifying the use of PSPS'[42] and SPD's observations stated above. Finally, SPD is willing to informally discuss with PG&E and parties alternatives to analyze PSPS in its wildfire risk analysis for PG&E's TY2023 GRC filing.

Mitigation M2 System Hardening

SPD recommends that M2 be divided into individual initiatives, especially for large non-related capital initiatives. SPD suggests only programs that are directly related to Covered Conductor or Undergrounding should be included in Risk Reduction and RSE calculations for these individual SH programs. Other initiatives that are not required as

[42] WSD-002 pg. 20.

part of Covered Conductor or Undergrounding should be separated into unique Mitigations with their own Risk Reduction and RSE calculations similar to PG&E's current M3 Non-Exempt Surge Arrestor Replacement Program and M4 Expulsion Fuse Replacement Program.

SPD recommends that PGE& provide MA Risk Reduction Scores, costs and RSEs for individual initiatives, as much as reasonably possible. Additionally, SPD recommends that PG&E provide appropriate mitigations associated with other SPD observations, findings, and recommendations for its wildfire MAVF model changes in its TY2023 GRC.

Controls

SPD also recommends PG&E provide RSE calculations or estimates for its controls. While the Settlement Agreement lexicon does adopt definitions that distinguish between "controls" and "mitigations", it remains important to have information on the effectiveness of controls, both to (1) gauge the relative efficiency of proposed mitigation and (2) to provide information to help understand the cost-effectiveness of the risk mitigations already in place.

SPD recommends PG&E include more individual initiatives for RSE analysis to understand the effectiveness and efficiency of each specific control and mitigation.

Wildfire Cross Cutting Mitigation Programs

SPD recommends that PG&E reassess how CCF Mitigation will reduce risk year by year especially if they are not capital projects that normally can take longer for implementation

FERC Transmission Mitigations

SPD also recommends PG&E provide information on certain wildfire safety mitigation work in FERC proceedings in their GRC filing. SPD recommends that PG&E include FERC Transmission project information, identified in their FERC Stakeholder Transmission Asset Review (STAR) process, and clearly explain its wildfire risk analysis justifying work in non-HFTD and HFTD areas for its transmission assets in its RAMP update in its upcoming TY 2023 GRC filing, even if funding for transmission assets are requested in FERC proceedings.

Alternative Analysis

SPD recommends that PG&E's proposed alternatives and others such as REFCL and Early Fault Detection be considered to address more granular tranches with associated RSE calculated to compare many alternatives for each tranche. This approach will support better investment decision-making.

RAMP Risk (Ch. 11): Failure of Electric Distribution Overhead Assets

Risk Description

Chapter 11 examines the failure of electric distribution overhead (DOH) assets, defined as the failure of assets associated with PG&E's overhead electrical distribution system or lack of remote operational functionality that may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy. However, 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, Third-Party Incident and Motor Vehicle Incident risks) are not within the scope of this risk mitigation chapter. In Chapter 15, regarding Third Party Safety Incidents, PG&E covers recordable third-party (public) injuries or fatalities due to interaction with or during the use of a PG&E facility, not involving asset failure.

PG&E's electrical overhead distribution system consists of more than 80,716 circuit miles of primary conductor and associated assets. Assets that are associated with the DOH system include the following: poles and support structures, primary and secondary conductors, voltage regulating equipment, protection equipment, switching equipment, transformers, and PG&E-owned streetlights. PG&E uses outages as a proxy for electric distribution overhead asset failures.

Observations

SPD finds that PG&E should adequately consider industry known safety risks to the public due to the interaction with any failed electric distribution overhead asset including energized wire-down powerlines. SPD recommends PG&E include risk analysis based on outage and wire-down data including whether the latter is energized versus non-energized. SPD suggests that if historical SIF data is lacking for this risk, then industry data may be an appropriate alternative to estimate risk outcomes.

Bow tie

The risk score for DOH assets is 526, ranking as the third highest risk, behind Wildfire (24,343) and Third-Party Safety (944).

PG&E forecasts approximately 24,834 risk events (outages) per year from 2023-2026 in the absence of proposed mitigations over those same years.

Observations

SPD identified issues with respect to the "Other" risk driver as well as the consequences. Specific comments about risk drivers and consequences can be found in the "Observations" within their respective sections below.

Exposure

Exposure to this risk in PG&E's risk model is based on the 80,716 circuit miles of primary overhead distribution lines in PG&E's electric system.

Tranches

PG&E identified the following five tranches for this risk event: two tranches for asset groups of circuits historically identified as carrying an increased risk for asset failure; and all remaining circuit miles divided into three tranches based on circuit reliability score percentiles provided in Electric Operations Work Plan 2020:

- Elevated wire-downs, i.e., small copper conductors (n=22,298 circuit miles or 28 percent of DOH system): "Small" is defined as any circuit with 7.5 percent or more of its length wired with either 4-CU or 6-CU conductor, or a combination of the two sizes. The Total Risk Score (TRS)[43] is 112.9.
- <u>Circuits with Aluminum Conductor Steel-Reinforced (ACSR) in Corrosion Zones</u> (n=4,796 circuit miles or six percent): Circuits with ACSR in designated corrosion zones in the Central Coast and Los Padres Divisions. The TRS is 55.8.
- <u>Poor Reliability Performance</u> (n=33,349 circuit miles or 41 percent): Circuits within 66th-100th percentile of the reliability scores. The TRS is 296.3.
- <u>Moderate Reliability Performance</u> (n=15,798 circuit miles or 20 percent): Circuits within 33rd-66th percentile of the reliability scores. The TRS is 54.8.
- <u>High Reliability Performance</u> (n=4,475 circuit miles or six percent): Circuits within 0-33rd percentile of the reliability scores. The TRS is 6.1.

Observations

SPD found that the tranches, particularly the Poor Reliability Performance tranche, are not adequately granular, as evidenced by: (1) the very uneven distribution of circuit miles among the five tranches; and (2) a comparison of the tranche TRS rankings to the *TRS per circuit mile* rankings. Of the systemwide DOH circuit miles alone, 41 percent are grouped into the Poor Reliability Performance tranche while the next largest tranche (Elevated Wires-Down) represents 28 percent of circuit miles (see Table 11-1). SPD finds the Poor Reliability Performance tranche, specifically, is not narrow enough in its risk characteristics. SPD recommends PG&E provide further granularity, particularly for the Poor Reliability Performance tranche, to be more homogenous risk profiles, as much as reasonably possible, as per the requirements of the S-MAP Settlement Agreement. TURN has expressed similar concerns more generally regarding tranches[44].

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[43] The Total Risk Score (TRS) is the sum of Safety Risk Score, Reliability Risk Score, and Financial Risk Score. TRS is also referred as the Multi-Attribute Risk Score (MARS).

[44] "The S-MAP Settlement requires that the risk analysis be broken down by "tranches" of assets. Under the Settlement, each tranche should have the same Likelihood of Risk Event and Consequence of Risk Event." (TURN Protest, pg. 3)

TABLE 11-1. PG&E Electric DOH Assets by Descending Total Risk Score

Tranche	Total Risk Score (TRS)	Circuit Miles	Percentage of All Circuit Miles	TRS per Circuit Mile *1000
Poor Reliability Perf.	296.3	33,349	41%	8.9
Elevated Wire-Downs	112.9	22,298	28%	5.1
ACSR in Corrosion Zones	55.8	4,796	6%	11.6
Moderate Reliability Perf.	54.8	15,798	20%	3.5
High Reliability Perf.	6.1	4,475	6%	1.4
Total	526	80,716	100%	7

The lack of granularity in the Poor Reliability Performance tranche is further emphasized by SPD's comparison of the tranche TRS rankings to the *TRS per circuit mile* rankings. The tranche for Poor Reliability Performance contains the highest total risk score, followed by Elevated Wire-Downs, ACSR Circuits in Corrosion Zones, Moderate Reliability Performance, and High Reliability Performance tranches (see Table 11-1). The TRS could lead parties to assume that the Poor Reliability Performance tranche, overall, represents the most vulnerable DOH circuit miles. But when SPD analyzed the TRS per circuit mile for each tranche, the ACSR Circuits in Corrosion Zones had the highest score and appears to contain the most vulnerable DOH circuit miles. Thus, SPD believes that the Poor Reliability Performance tranche should be further subdivided into more granular tranches that would more accurately reflect common risk exposures, as indicated by both the TRS and TRS per circuit mile. SPD acknowledges, however, that PG&E's development of more granular tranches may depend on the availability of data or the development of specific machine learning techniques to sort DOH assets into groups with common risk profiles. Sufficient granularity will help PG&E target and prioritize resources and mitigation efforts more effectively.

Risk Drivers and Associated Frequencies

PG&E identified nine key risk drivers[45] accounting for a forecasted 24,834 risk events (i.e., outages) per year from 2023-2026:

- Distribution Line Equipment Failure (n=8,663 outages or 35 percent)
- Other (unknown causes) (n=7,348 or 30 percent)
- Vegetation (n=5,729 or 21 percent)

[45] PG&E also identified 61 sub-drivers that are not discussed in this summary.

- Animal (n=1,999 or eight percent)
- Natural Hazard (n=1,188 or five percent)
- Other PG&E Assets or Processes (n=149 or one percent)
- Human Performance (n=119 or less than one percent)
- Seismic Scenario (Cross-Cutting) (n=41 or less than one percent)
- Skilled and Qualified Workforce (Cross-Cutting) (n=15 or less than one percent)

The Distribution Line Equipment Failure and Vegetation drivers together account for 56 percent of the estimated outages. The Other driver accounts for 30 percent of the risk events. The remaining drivers are estimated to cause 14 percent of risk events.

Observations

A major point of potential inadequacy in the risk driver is the "Other" category which is projected to account for 7,348 annual risk events or outages, or 30 percent. SPD considers a risk this large without being clearly identified or defined to be a deficiency in the risk analysis.

Cross-Cutting Factors

PG&E presents eight cross-cutting factors in the 2020 RAMP. Climate change, physical attack, records and information management, seismic, and skilled and qualified workforce factors impact likelihood of a risk event, while emergency preparedness and response, information technology asset failure, records and information management, and seismic factors impact the consequence of a risk event.

Four cross-cutting factors – seismic scenario, physical attack, skilled and qualified workforce, and records and information management – are also considered risk drivers in the risk bow tie with a collective frequency of less than 0.5 percent.

Two cross-cutting factors are consequence factors – seismic scenario and IT asset failure– with a collective frequency of about 0.3 percent.

Observations

The cross-cutting factors included as risk drivers and outcomes are relatively insignificant.

Consequences

The failure of DOH assets bow tie includes four outcomes for an asset failure:

- Asset failures associated with an ignition (less than two percent frequency);
- Asset failures associated with a seismic scenario (less than one percent frequency);
- Asset failures associated with an IT asset (less than one percent frequency); and

- Failure not associated with an ignition and not coincident with IT asset failure (98 percent frequency)

Because consequences of failures associated with ignitions are considered in PG&E's Wildfire risk model, PG&E sets the risk score of these incidents to zero.

Controls and Mitigations

PG&E defines controls as currently established measures that modify risk, such as programs required by law or policy, while mitigations are proposed measures designed to reduce one or more of the risk driver frequencies or to modify the consequence outcomes of one or more attributes.

PG&E did not include Failure of DOH Assets as a 2017 RAMP risk, but it did include the Distribution Overhead Conductor – Primary (DOCP) risk, most of which is now integrated into the Failure of DOH Assets risk.

Controls in the 2020-2026 RAMP include the following 13 controls (with mapping to 2017 RAMP and/or 2020 GRC):

- C1 – Vegetation management – distribution overhead (C2 in 2017 RAMP and 2020 GRC);
- C2 – Vegetation management – catastrophic emergency memorandum account (CEMA) (C3 in 2017 RAMP and 2020 GRC);
- C3 – Equipment preventive maintenance and replacement – distribution overhead (C4 in 2017 RAMP and 2020 GRC);
- C4 – Overhead conductor replacement (C5 in 2017 RAMP and 2020 GRC);
- C5 – Patrols and inspections – distribution overhead (C6 in 2017 RAMP and 2020 GRC);
- C6 – Overhead infrared inspections (C7 in 2017 RAMP and 2020 GRC);
- C7 – Supervisory control and data acquisition (SCADA) (C9 in 2017 RAMP and 2020 GRC);
- C8 – Annual protection reviews (C10 in 2017 RAMP and 2020 GRC);
- C9 – Electric distribution line and equipment capacity (C11 in 2017 RAMP and 2020 GRC);
- C10 – Design standards;
- C11 – Pole programs;
- C12 – Targeted reliability program (C8 in 2017 RAMP); and
- C13 – Enhanced inspections – distribution.

Mitigations in the 2023-2026 RAMP are shown in Table 11-2, along with their forecasted costs, RSE, and risk reduction scores.

TABLE 11-2. Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026

Program	Costs ($000s)	RSE	Risk Reduction
M1 – Enhanced Vegetation Management	[a]	[a]	16.5
M2 – System Hardening	[a]	[a]	122.0
M3 – Non-Exempt Surge Arrester Replacement	$47,686	0.02	0.8
M4 – Expulsion Fuse Replacement	[a]	[a]	0.4
M5 – Additional Asset Data Capture	$5,366	[b]	[b]
M6 – Grasshopper/KPF Switch Replacement	$3,674	3.69	10.3
M7 – RO Streetlight Replacement	$5,277	<0.01	<0.01
M8 – Ceramic Post Insulator Replacement	$1,310	0.72	0.8
M9 – Improved Distribution Risk Model	$6,261	[b]	[b]
M10 – 3A and 4C Line Recloser Replacement	$36,222	1.54 [c]	37.0
Total	$105,796	-	-

[a] The costs and RSE of this mitigation are aligned to the Wildfire risk (Chapter 10).
[b] Foundational mitigation. PG&E does not calculate an RSE or risk reduction score for foundational mitigations.
[C] The RSE includes the risk reduction for both the Failure of Electric Distribution Overhead Assets risk and the Third-Party Safety Incident risk.

Risk Spend Efficiency for Controls and Mitigations

The risk reduction for M1-EVM, M2-System Hardening, M10-3A and 4C Line Recloser Replacement, and M6-Grasshopper and KPF Switch Replacement are relatively high.

However, M1-EVM, M2-System Hardening, and M4-Expulsion Fuse Replacement have RSE values that are aligned to the Wildfire risk in Chapter 10 as an aggregate risk reduction because they are primarily targeted at reducing PG&E’s Wildfire risk while also reducing the number of outages due to equipment failure in the areas where they are implemented. M10-3A and 4C Line Recloser Replacement has an RSE in Chapter 11 of 1.54 and accounts for 34 percent of 2023-2026 spending on mitigations that are primarily for the failure of DOH assets.

Observations

M1, M2, and M4 are mitigations with costs and investments that are addressed wholly in the wildfire chapter (Ch. 10) although relevant and important to mitigate non-wildfire DOH asset risks found in Chapter 11.

Alternatives Analysis

PG&E considered the four following alternative mitigations in Chapter 11:

Alternative Plan 1 (A1) is the use of M11a – Remote Grid, which is the potential expansion of the Remote Grid program in M11, implemented in 2020. Since PG&E has not determined the scale or future location of additional Remote Grid projects, they continue to use the baseline for M11 in 2023-2026 for modeling purposes.

Alternative Plan 2 (A2) is the use of M12 – Targeted Transformer Replacement to Mitigate Overloading. PG&E estimates that up to one percent of the 750,000 overhead transformers in its electric distribution system could become susceptible to failure from overloading due to demand over the next 10-20 years. PG&E is evaluating a program that identifies and upgrades the most vulnerable of these overhead transformers. PG&E is continuing to develop this program and may present it as a mitigation in the 2023 GRC.

Alternative Plan 3 (A3) is the use of targeted system upgrades to reduce Wildfire risk. These are lower cost mitigations that also result in lower risk reduction. The mitigations include animal protection work; work to improve separation between phases of conductor; assessment of poles under current pole loading standards; the use of trusses, guys, or pole replacement to bring deficient poles up to standard; and other mitigations. PG&E is modeling this alternative as part of a mitigation plan that would include the currently forecast amount of M2 System Hardening work, plus sufficient additional mileage of A3 work. The RSE are aligned with the Wildfire risk, as an aggregate risk.

Alternative Plan 4 (A4) is the use of system hardening hybrid, a package of system modifications that falls somewhere between the existing M2 mitigation and A3, such as the replacing of existing bare wire with covered conductor that is lighter than the current M2 specification. PG&E is modeling this alternative as part of a mitigation plan that would include the currently forecast amount of M2 System Hardening work, plus sufficient additional mileage of A4 work. PG&E may present A4 as a mitigation in the 2023 GRC.

Observations

Each of the alternatives discussed are likely to be future mitigations, all of which are primarily tied to the mitigations of Wildfire risk, except for A2.

Summary of Findings

*Risk Descripti*on

SPD finds that PG&E should adequately consider industry known safety risks to the public due to the interaction with any failed electric distribution overhead asset including energized wire-down powerlines.

Tranches

The tranches developed by PG&E for the 2020 RAMP are not sufficiently granular to prioritize asset-level risk mitigations. SPD compared both the distribution of circuit miles across the five tranches developed by PG&E and both the TRS and *TRS per circuit mile* for each tranche. The Poor Reliability Performance tranche stood out for being too broad of an asset grouping because it is made up of 41 percent of all DOH circuit miles. Although this tranche has the highest TRS among all tranches, when SPD evaluated the TRS per circuit mile, the tranche ranked second to ACSR Circuits in Corrosion Zones trance by nearly three points per circuit mile (see Table 11-A). As such, SPD believes that the tranches, and the Poor Reliability Performance tranche in particular, are not arranged narrowly enough into groups that reflect a specific set of risk characteristics. Sufficient granularity will help PG&E target and prioritize resources and mitigation efforts more effectively.

Driver Labeled "Other"

The definition and scope of PG&E's second largest risk driver for this risk section is "Other," accounting for 7,348 (30 percent) of the 24,834 annual expected number of outages. PG&E defined this driver as "failure events without known causes."[46] SPD considers a risk this large without being clearly identified or defined to be a deficiency in the risk analysis.

Without a full explanation and accounting of the problems that are causing the outages assigned to "Others," PG&E's discussion of controls that would mitigate "Other" risk drivers are not based on sound assumptions and do not specifically target an identified risk. For example, PG&E identifies C7-SCADA as one of two controls with the potential to reduce the risk driver "Other." C7-SCADA includes the installation, upgrade, and replacement of remotely controlled automation and protection equipment in distribution substations and on feeder circuits. This work improves operating efficiency, enables better outage response and diagnosis, improves system protection, and improves employee and public safety by enabling PG&E to automatically and remotely de-energize lines in response to emergencies such as wires down. A SCADA system would potentially mitigate the "Other" risk driver because it is installed or upgraded on problem circuits and would generate more data to help identify the issues on the circuit. And because the circuit will have immediate controls governing it, isolation would be

[46] RAMP 2020, pg. 11-10.

automatic during line issues. However, the upgraded control still does not explain how this added control can specifically address the "Other" risk driver in a targeted way.

PG&E also identified C9-Electric Distribution Line and Equipment Capacity as the other control with "the potential to reduce the D-Line Equipment Failure and Other drivers"[47]. C9 includes the mitigation of existing or projected overloads and voltage levels, having anomalies that can also lead to equipment failure. The failure of overloaded line equipment and conductors can lead to reduced service reliability and public safety concerns, such as wires down. To address potential overload conditions before they occur, PG&E would install and/or replace equipment to increase capacity. These projects can sometimes include conductor replacement.[48] Although PG&E's assumption that some of the unidentified outages are caused by overloaded line equipment and conductors may be correct, they do not know what percentage of these "Other" outages are due to overload conditions on their circuits.

Wildfire Controls and Mitigations

PG&E determined that Asset Failures Associated with an Ignition is one of four outcomes in its bowtie analysis. This outcome described a situation in which an ignition was associated with an outage on the DOH system. But because PG&E considered asset failures associated with an ignition in PG&E's Wildfire risk model, the risk bowtie for the failure risk of DOH assets sets the risk score of these incidents to zero.

PG&E discussed three mitigations – M1-EVM, M2-System Hardening, and M4-Expulsion Fuse Replacement – that are only being implemented in the PG&E's HFTD areas. PG&E stated that M1-EVM is intended primarily as a mitigation for the Wildfire risk, but that EVM also has the potential to reduce the Vegetation driver of the Failure of Electric Distribution Overhead Assets risk.[49]

Similarly, M2-System Hardening is also intended primarily as a mitigation for the Wildfire risk. This mitigation is an ongoing, long-term capital investment program intended to rebuild portions of PG&E's overhead electric distribution system. Over the course of this program, the utility proposes to upgrade approximately 7,100 miles of overhead distribution circuits in HFTD areas. M2-System Hardening is expected to reduce the D-Line Equipment Failure, Animal, Natural Hazard, Other, Other PG&E Assets or Processes and Vegetation driver of the Failure of Electric Overhead Assets risk.[50]

M4-Expulsion Fuse Replacement is also intended primarily as a mitigation for the Wildfire risk. PG&E targeted the replacement of non-exempt fuses on poles located in HFTD areas. Although the primary purpose of this program is to reduce Wildfire risk,

[47] RAMP 2020, pg. 11-21.
[48] RAMP 2020, pg. 11-21.
[49] RAMP 2020, pg.11-22
[50] RAMP 2020, pg.11-22

PG&E reported that it will also reduce the risk of equipment failure associated with the fuses that are replaced. This mitigation has the potential to reduce the D-Line Equipment Failure driver.[51]

M1, M2, and M4 are all mitigations with costs investments that are addressed wholly in the wildfire chapter (Ch. 10) even though M1 and M2 should also function as primary mitigations for the reduction of DOH asset failure risk found in Chapter 11.

Recommended Solutions to Address Findings and Deficiencies

Risk Description

As noted above, SPD recommends PG&E include risk analysis based on outage and wire-down data including whether the latter is energized versus non-energized. SPD suggests that if historical SIF data is lacking for this risk, then industry data may be an appropriate alternative to estimate risk outcomes.

Tranches

SPD recommends that PG&E develop more granular tranches for its DOH assets, through a thorough re-examination of available data and the possible application of machine learning techniques that could help identify more narrow homogenous risk profiles than ones that have been currently developed. PG&E should also consider any insight derived from initial SME-proposed initiatives to mitigate DOH asset risks, which could help the utility understand how it prioritizes certain assets by common risk characteristics and which would then be classified by its own tranche. PG&E should also consider arranging the primary circuits into tranches according to well-defined geographic areas, such as counties, if there is enough justification to indicate a homogenous risk profile for circuits within each area.

At a minimum, PG&E needs to find a way to subdivide the assets in the Poor Reliability Performance tranche, which makes up 41 percent of PG&E's DOH circuits, into smaller and more homogenous tranches.

PG&E should also consider using the same tranches for the DOH asset failure risk that will be developed for the Wildfire risk, to the degree that the tranches are relevant (before sub-tranches become specific to Wildfire risk alone), since the same assets are affected by both risks and overlapping mitigations reduce both outages and ignitions.

Driver Labeled "Other"

"Other" is a large area of risk that is not well defined or explained, making it difficult – or even impossible – to develop controls and mitigations for risks that are not clearly identified or defined. Therefore, PG&E's efforts to mitigate this particular risk driver are

[51] RAMP 2020, pg.11-23

not targeted and may ultimately result in suboptimal safety spending efficiency. The utility needs to conduct more research to identify the root cause of these undetermined outages. PG&E should consider additional efforts to address the "Other" category of unknown causes since it makes up such a large proportion of the risk drivers, including the possible use of machine learning techniques or artificial intelligence that could group or sort conditions or characteristics within the "Other" category to create more specific risk drivers.

There are also new tools and technologies available to PG&E, such as line sensors, that can help identify problems like bad splices and locate failing conductors. These sensors can provide near-instantaneous feedback that a power line is down. There are other tools such as enhanced infrared imaging to detect hot spots on distribution lines, transmission lines, and line components, which PG&E is already utilizing in their wildfire Tier 2 and 3 areas. SPD recommends that PG&E use the tools that they are already using in the HFTDs and newer line sensor technologies to determine more accurately what is causing the outages that are grouped under the risk driver labeled "Other." By reducing the size of the "Other" risk drivers through the identification of specific issues in this category, PG&E will develop more targeted and more effective mitigations to address risks.

Wildfire Controls and Mitigations

PG&E discusses three mitigations – M1 "EVM," M2 "System Hardening," and M4 "Expulsion Fuse Replacement" – that address problems that are required to be dealt with in its Wildfire Mitigation Plan, for the wildfire HFTD areas. Because California electric IOUs are required to mitigate wildfire risks, PG&E applies the full expenditure value of these mitigations in the Wildfire section (Chapter 10).

SPD recommends that PG&E consider how it can better reflect DOH asset risk reductions and RSEs for wildfire controls and mitigations, particularly in HFTD areas while still addressing DOH asset risks in non-HFTD areas.

As recommended in previous chapters reviews, staff believes the inclusion of RSE for all existing controls and proposed mitigations would better enable the Commission and intervenors to carry out public interest oversight. This additional information should be provided as PG&E proceeds with the TY 2023 GRC.

RAMP Risk (Ch. 12): Failure of Electric Distribution Network Assets

Risk Description

Chapter 12 examines the Failure of Electric Distribution Network Assets associated with urban underground electrical distribution networks in downtown San Francisco and Oakland, including primary and secondary network cables, network transformers, and network protectors. The risk is defined as the failure of distribution network assets or lack of remote operation functionality that may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.

Failure of assets associated with underground transmission cables or the non-network aspects of the underground distribution system are considered out of scope in this chapter.

Failure of Electric Distribution Network Assets was not included in the 2017 RAMP. The 2017 RAMP noted that there was a risk on the Electric Operations (EO) risk register called "Network Components (in Urban/High Density Areas)," which was equivalent to this chapter's risk, but it did not have a high enough risk score to be included as a 2017 RAMP risk. However, at the end of 2019, PG&E changed its methodology for estimating the potentially high safety consequence incidents from this risk by using adjustments provided by SMEs. Once PG&E adjusted its model, the risk score went up, causing it to have a score high enough to be included as a risk in the 2020 RAMP.

Observation

Assets specific to underground electrical distribution networks are located in downtown San Francisco and Oakland. In PG&E's territory, only the downtown areas of San Francisco and Oakland are served by the secondary network system, which is designed to meet the area's higher reliability needs and limited space.[52] Secondary network systems have been used for many years by electric utility companies to serve high-density load areas in the downtown section of cities and consists of grids of interconnected cables supplied at numerous points by network transformers which feed the grid through network protectors. A given secondary network is supplied by several primary feeders suitably interlaced through the area in order to achieve acceptable loading of the transformers under emergency conditions and to provide a system of extremely high service reliability.[53]

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[52] PG&E, "Secondary Networks." Last accessed Nov. 23, 2020. https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/energy-transmission-and-storage/secondary-networks/secondary-networks.page?ctx=business

[53] Standard Handbook for Electrical Engineers, 13th Edition, Donald G. Fink / H. Wayne Beaty, pp 18-79 to 18-80.

Other cities in PG&E's service territory with underground electric distribution assets do not have what PG&E considers Electric Distribution Network Assets. Those other cities have what PG&E refers to as Electric Distribution Underground Assets, representing 26,000 circuit miles of underground radial distribution cable. The risk associated with Electric Distribution Underground Assets can be found in Chapter 19 in a discussion on "Other Safety Risks" and does not meet the safety risk score threshold for inclusion in the 2020 RAMP.

Bow tie

The risk score for Underground Distribution Network Assets is seven, ranking as the lowest risk among those identified by PG&E in its 2020 RAMP Application.

PG&E forecasts approximately 10.2 risk events (outages) per year from 2023-2026 in the absence of proposed mitigations over those same years.

The bow tie analysis identified seven risk drivers, four of which are cross-cutting factors and one of which did not account for any network asset failures in the historical data.

Observations

The bow tie meets the requirements of the settlement agreement and represents a reasonable estimate of the risk probabilities and consequences, as recently adjusted by PG&E to account for the possibility of higher safety consequence incidents.

Exposure

PG&E maintains approximately 188 circuit miles of networked circuits. The Failure of Electric Distribution Network Assets risk exposure includes all network cable, network transformers, and other associated equipment such as network protectors and relays.

Observations

The Underground Electrical Distribution Network assets only include PG&E territory served by the secondary network system. None of the underground radial distribution cables found in PG&E's service territory are included in this risk. The fact that PG&E only has 188 circuit miles of secondary network cable is a factor for why this is the lowest ranked risk in the RAMP.

Tranches

PG&E identified the following three tranches for this risk event based on differences in the network asset replacement strategy:

- <u>Circuits with a High Failure Rate</u> (n=132 circuit miles or 70 percent of network distribution system): These circuits are prioritized for replacement based on failures and cable testing. These circuits are associated with 89 percent of network asset failure risk with a Total Risk Score of 5.88.

- Reconductored Circuits (n=33 circuit miles or 18 percent): These circuits have had their older vintage network cables replaced as of end of year 2019. These circuits are associated with one percent of network asset failure risk with a Total Risk Score of 0.09.
- All Other Circuits (n=23 circuit miles or 12 percent): These circuits are associated with nine percent of network asset failure risk with a Total Risk Score of 0.61.

Observations

Although the total number of circuit miles under discussion is small, 70 percent of the circuit miles are grouped into a single tranche – Circuits with a High Failure Rate. SPD computed the ratio of the Total Risk Score per circuit mile for this tranche * 1000 to be 44.5 which SPD finds is almost four times the similar ratio for DOH Asset ACSR tranche (Chapter 11). Assuming the Network Assets MAVF risk analysis accurately reflects risk likelihoods and consequences, SPD finds that the limited network asset circuit miles in each tranche and the limited exposure, confined to two specific geographic areas, allows for not only evaluating and assessing the risks but also enables prioritization of high failure rate secondary network assets to mitigate this high-risk tranche.

Risk Drivers and Associated Frequencies

PG&E identified seven drivers (four of which are cross-cutting factors) and 24 sub-drivers of the failure of electric distribution network assets risk:

- D1 – Underground Network Equipment Failure (n=7.9 outages or 77 percent)
- D2 – Human Performance (n=2 or 19 percent)
- D3 – Seismic Scenario (Cross-cutting) (n=0.8 or less than one percent)
- D4 – Skilled and Qualified Workforce (Cross-cutting) (n=0.2 or two percent)
- D5 – Records and Information Management (Cross-cutting) (n=0.8 or less than one percent)
- D6 – Physical Attack (n=0.1 or less than one percent)
- D7 – Natural Hazards (these events did not account for any network asset failures in the historical data).

The underground network equipment failure and human performance drivers combine to account for 96 percent of the source events.

Observations

The risk drivers are in line with staff expectations. However, natural hazards may be underemphasized as a risk driver due to limited years of historical data.

Cross-Cutting Factors

PG&E presents eight cross-cutting factors in the 2020 RAMP. Five cross-cutting factors have been identified as impacting the likelihood of a risk events on distribution network assets risk: (1) climate change; (2) physical attack; (3) records and information management; (4) seismic; and (5) skilled and qualified workforce. Three cross-cutting factors have been identified as impacting the consequence of a risk event: emergency preparedness and response, records and information management, and seismic.

Four cross-cutting factors – seismic scenario, physical attack, skilled and qualified workforce, and records and information management – are also considered risk drivers in the bow tie analysis with a collective frequency of approximately four percent.

One cross-cutting factor is also listed as a consequence factor in the bow tie analysis – seismic scenario and IT asset failure – with a frequency of about one percent.

Observations

The risk drivers are in line with staff expectations. The cross-cutting factors included as risk drivers and outcomes are relatively insignificant in the bowtie analysis.

Consequences

The Failure of Underground Distribution Network Assets bowtie analysis includes three outcomes for an asset failure:

- Asset failures related to a seismic scenario (one percent frequency and one percent risk score)
- Catastrophic asset failures not associated with a seismic scenario (18 percent frequency and 96 percent risk score)
- Non-catastrophic asset failures not associated with a seismic scenario (81 percent frequency and three percent risk score)

While the vast majority of outcomes are non-catastrophic, they only make up three percent of the risk score. Catastrophic asset failures not associated with a seismic scenario, on the other hand, are far less frequent but make up 96 percent of the risk score.

Observations

As discussed earlier in this chapter review, PG&E was previously concerned that it may have been understating the potential for high safety consequence incidents of asset failure due to the infrequent nature of historical data in the utility's Electric Incident Reports. PG&E adjusted its model to assume that an asset failure would result in a serious injury incident once every 10 years and a fatality incident once every 15 years.

Controls and Mitigations

PG&E defines controls as currently established measures that modify risk, such as programs required by law or policy, while mitigations are proposed measures designed to reduce one or more of the risk driver frequencies or to modify the consequence outcomes of one or more attributes.

Because the Failure of Electric Distribution Network Assets risk was not included in the 2017 RAMP, PG&E has not previously presented a list of controls and mitigations for this risk. For the 2020-2026 period, PG&E plans to continue with the following controls that were in place as of 2019.

Controls include the following:

- C1 – Network Cable Replacement and Switch Installations,
- C2 – Network Maintenance and Corrective Work,
- C3 – Network Component (Transformer, Protector) Replacements Condition Based,
- C4 – Asset Information Improvements/Asset Data Comparison and Updates,
- C5 – Network Health Report (Units Offline),
- C6 – Standards, Processes, and Training,
- C7 – Supervisory control and data acquisition,
- C8 – Annual protection reviews,
- C9 – Electric distribution line and equipment capacity,
- C10 – Design standards,
- C11 – Pole programs, and
- C12 – Targeted reliability program.

Mitigations include the following for 2020-2022:

- M1 – Network component replacements – high-rise oil-filled transformers,
- M2 – Venting manhole cover replacements, and
- M3 – Installation of SCADA equipment for safety monitoring

PG&E expected to complete mitigation work for M1 and M2 by the end of 2022.

Subsequently, starting in 2023-2026, PG&E will invest in the following planned mitigations while continuing investments in M3-Installation of SCADA:

- M4 – Incremental primary network cable replacements (RSE = 0.07 and Risk Reduction = 1.44),
- M5 – Network component replacements – high-rise dry-type transformers (RSE = <0.01 and Risk Reduction <0.01),
- M6 – Network component replacements – targeted network protector replacement (RSE = 0.37 and Risk Reduction = 1.85)

Observations

PG&E expects to actively carry out work for three mitigations in 2023-2026.

Risk Spend Efficiency for Controls and Mitigations

Table 12-1 displays the forecasted costs, the RSE, and the risk score reduction from 2023-2026. PG&E expects to complete mitigation work for M1 and M2 by the end of 2022.

The M3-Installation of SCADA makes up about 45 percent of mitigation spending for the 2023-2026 period. PG&E considers this a foundational activity (and has not calculated a risk score or RSE) because it does not directly reduce risk, but instead provides information about the network system, including equipment condition, that can be used to reduce risk.

TABLE 12-1. Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026.

Program	Costs ($000s)	RSE	Risk Reduction
M1 - Network Component Replacements - High-Rise Oil Filled Transformers [a]	-	-	-
M2 - Venting Manhole Cover Replacements [b]	-	-	-
M3 - Installation of SCADA	$38,774	[c]	[c]
M4 - Incremental Primary Network Cable Replacements	$27,033	0.07	1.44
M5 - Network Component Replacements - High-Rise Dry-Type Transformers	$10,992	<0.01	<0.01
M6 - Network Component Replacements - CMD-Type Network Protectors	$6,708	0.37	1.85
Total	$83,507	-	-

[a] Mitigation work is expected to be completed by end of 2022.
[b] Mitigation work is expected to be completed by end of 2022.
[c] PG&E considers M3 to be a foundational mitigation and does not calculate RSE or risk reduction.

Observations

M6 and M4, respectively, carry the highest RSE and Risk Reduction scores, with M5 having the lowest RSE and Risk Reduction scores. However, PG&E believes that its current model understates the risk reduction potential of M5, as the consequences of a failure of any dry-type, high rise transformers would be much more severe than failure of a “typical” network transformer.

The M3-Installation of SCADA mitigation does not include an RSE or a Risk Reduction score since it is a foundational mitigation. PG&E should consider ways to model Risks and RSE for foundational mitigations in general.

Alternatives Analysis

PG&E considered three alternative mitigations in Chapter 12.

Alternative Plan 1 (A1) is to Install Completely Submersible SCADA Enclosures. Due to the risks associated with climate change, PG&E is worried about more frequent flooding of underground vaults containing network equipment. The submersible SCADA enclosures would prevent SCADA system components in vaults from failing due to flood waters. PG&E is still modeling the risk associated with SCADA component failure as it does not directly result in the loss of power. Therefore, there is no RSE calculated for this program yet. However, the total cost to install SCADA enclosures on about 710 locations is nearly $36 million, from 2023 through 2026. PG&E may present it as a mitigation program in the 2023 GRC.

Alternative Plan 2 (A2) or M5a is to Reduce Proposed Rate of Dry-Type Transformer Replacement. The M5 mitigation aims to replace 22 dry-type network transformers in four high-rise buildings in San Francisco and Oakland over three years (2023-25) while the proposal in A2 would aim to replace those same transformers over six years (2023-28). Ultimately, PG&E rejected A2 because of rising year-over-year costs in labor contracts and installation permits over six years and the slower reduction of risk compared to the three-year plan. The total cost of this alternative is nearly $7.4 million from 2023-2026, not including increasing costs in 2027 and 2028 (compared to nearly $11 million for M5 from 2023-25) for an RSE of <0.001 and a risk reduction score of 0.002.

Alternative Plan 3 (A3) is to Replace Network Transformers Based on Age, Instead of Condition. This alternative mitigation considers the impact of changing from a condition-based replacement program to an age-based replacement program for the network transformers. PG&E determined that A3 would reduce inspection costs (based on conditions) by approximately $2.4 million while increasing the overall risk of transformer failure by approximately 9.3 percent, a standard that PG&E found to be unacceptable.

Observations

As a separate alternative, SPD suggests that PG&E provide a risk spend efficiency analysis of A3 as a combined program with the condition-based replacement program for the network transformers. PG&E claims that, on average, they replace about 12 transformers per year under the condition-based replacement program and would expect to replace the same number from 2023-2026 under the age-based replacement scenario. An alternative mitigation of the two programs combined would replace an estimated 12-24 transformers and reduce risk by a greater magnitude than either program alone.

PG&E is still considering A1 for inclusion in the 2023 GRC.

Summary of Findings

Exposure

The fact that PG&E only has 188 circuit miles of secondary network cable is a factor for why this is the lowest ranked risk in the RAMP.

Tranches

Although the total number of circuit miles under discussion is small, 70 percent of the circuit miles are grouped into a single tranche – Circuits with a High Failure Rate. SPD computed the ratio of the Total Risk Score per circuit mile for this tranche * 1000 to be 44.5 which SPD finds is almost four times the similar ratio for DOH Asset ACSR tranche in Chapter 11. Assuming the Network Assets MAVF risk analysis accurately reflects risk likelihoods and consequences, SPD finds that the limited network asset circuit miles in each tranche and the limited exposure, confined to two specific geographic areas, allows for not only evaluating and assessing the risks but also enables prioritization of high failure rate secondary network assets to mitigate this high-risk tranche.

M5- Network Component Replacements - High-Rise Dry-Type Transformers

M5 holds the lowest projected RSE and Risk Reduction scores even though PG&E believes that its current model understates the risk reduction potential of M5, as the consequences of a failure of any dry-type, high-rise transformers would be much more severe than the failure of a "typical" network transformer.

M3-Installation of SCADA

PG&E lists M3-Installation of SCADA as a mitigation, but because the utility considers SCADA to be a "foundational" mitigation, PG&E does not calculate an RSE or a Risk Reduction score. However, PG&E is thinking about modeling the risk associated with SCADA component failure in Alternative Plan 1.

Alternative Plan 3: A3 – Replace Network Transformers Based on Age, Instead of Condition

PG&E analyzed Alternative Plan 3 as a program that would run in lieu of the condition-based transformer replacement program. By fully replacing the condition-based transformer replacement program, PG&E determined that A3 would reduce inspection costs (based on conditions) by approximately $2.4 million while increasing the overall risk of transformer failure by approximately 9.3 percent, a standard that PG&E found to be unacceptable. PG&E should provide a risk spend efficiency analysis of A3 as a combined program with the condition-based replacement program for the network transformers.

Recommended Solutions to Address Findings and Deficiencies

M3-Installation of SCADA

The M3-Installation of SCADA mitigation does not include an RSE or a Risk Reduction score since it is a foundational mitigation. PG&E should consider ways to model Risks and RSE for foundational mitigations in general.

Alternative Plan 3: A3 – Replace Network Transformers Based on Age, Instead of Condition

Staff recommends that PG&E analyze an alternative plan that combines the program for replacing network transformers based on age alongside the program for replacing network transformers based on condition. PG&E claims that, on average, they replace about 12 transformers per year under the condition-based replacement program alone and would expect to replace the same number from 2023-2026 under the age-based replacement scenario alone. The two programs working together are expected to replace an estimated 12-24 transformers and reduce risk by a greater magnitude than either program alone. Staff suggests that PG&E analyze a program that acts on asset age or condition, instead of only one of the two, and provide assumptions what such a program could cost and what the associated RSE and risk reduction scores could be.

RAMP Risk (Ch. 13): Large Uncontrolled Water Release

Risk Description

PG&E evaluated the risk of a large, uncontrolled release of water from each of their 61 dams classified by the Federal Energy Regulatory Commission (FERC) as high or significant hazards.

Observations

PG&E's dam operations are overseen by both FERC and the California Department of Water Resources' (DWR) Division of Safety of Dams (DSOD). This regulatory oversight includes regular inspections overseen by FERC and DSOD at intervals of one to three years depending on the hazard classification. Additionally, federal regulations require that PG&E hire an independent qualified dam safety consultant to perform inspection of its high and significant hazard dams every five years.

Bow tie

Each dam is given a catastrophic failure likelihood, expressed as a percentage, for the risk drivers of flood, seismic event, internal erosion, and physical attack. The characteristics of each dam informed the estimates. PG&E estimated a risk score of 70, making it the eighth highest risk score.

Observations

Staff finds that the bow tie comports with the requirements of the settlement and represents a reasonable estimate of the risk probabilities and attendant consequences.

Exposure

In this RAMP, exposure is generally limited to communities, environments, and infrastructure within the inundation zones established in PG&E's Emergency Action Plans downstream from the 61 dams classified by FERC as high or significant hazards.

Tranches

Each of PG&E's 61 dams classified by FERC as high or significant hazards constitutes a tranche. The dams and associated facilities were specifically evaluated in either annual or triennial inspections as required.

Observations

Evaluating the risks of each individual dam and associated infrastructure reflects an appropriately granular level of analysis for risks in this chapter.

Risk Drivers

PG&E identified four drivers and two sub-drivers for the Large Uncontrolled Water Release risk: flooding, seismic, internal erosion, and physical attack. The risk drivers identified by PG&E are roughly proportional to the attributed causes of dam failures identified by the Association of State Dam Safety Officials.[54]

Flooding can result from heavy precipitation, rapid snowmelt, equipment failure, or sudden releases of upstream water controls. PG&E calculated the cumulative likelihood of a catastrophic dam failure for the 61 dams they analyzed as one possible event in 77 years. Flood accounted for 86 percent of the 0.015 expected annual events.

For seismic risk, PG&E evaluated each concrete and embankment dam using a combination of anticipated ground motion and expected dam response based on based on the characteristics of the dams. The aggregated evaluation of all 61 dams resulted in an average likelihood that one seismic event with the potential to cause dam failure could occur every 714 years. Seismic events accounted for 10 percent of the 0.015 expected annual number of events.

Internal erosion occurs when water migrates through the dam structure. PG&E aggregated the variable possibilities of earthen dams, rockfill dams, and concrete dams failing because of internal erosion and found that the average likelihood of failure is once every 1,667 years accounting for four percent of the 0.015 expected annual number of events.

PG&E found "no instances of a dam failure driven by Physical Attack in the United States." The 2020 RAMP assigns an event frequency for a physical attack leading to a catastrophic failure of once per 4.4 million years. Despite the low likelihood of this event, PG&E conducts security assessments in accordance with FERC's Hydropower Security Program guidance.

PG&E also identified two sub drivers, IT asset failure and cyber-attack, that could increase the likelihood that a catastrophic outcome would occur if coincident with the main risk drivers. The estimated frequency for IT asset failure event is one in 26 years. The estimated frequency of a cyber-attack event is one in 280 years.

Observations

Staff finds the identified risk drivers are appropriate factors that contribute to the likelihood of failure.

[54] National Association of Dam Safety Officials Dam failures and incidents data available at Damsafety.org

Cross-cutting factors

Cross-cutting factors impacting the likelihood of large uncontrolled water releases include climate change, cyber-attacks, IT asset failure, physical attacks, and seismic risks. Emergency preparedness and response and records and information management impact the consequences.

Consequences

To analyze consequences of large uncontrolled water releases, PG&E relied on inundation maps developed for their emergency action plans. Based on FERC and DSOD guidelines, the inundations maps display areas that would be impacted by water release events. PG&E relied on estimates from subject matter experts to estimate site specific consequences, based on "dam-specific inspections, technical documents, and industry data."

- Safety: PG&E used the Dekay-McClelland[55] empirical method to estimate loss of life based on possible warning time, the estimated population at risk, and the potential forcefulness of the flood waters. The calculations were run for each of PG&E's dams to create a distribution sample of fatalities resulting from dam failure. For injuries, PG&E used a ratio of 1.87 injuries per fatality from the National Oceanic and Atmospheric Administration's California flood data. This model and assumptions result in an average annualized safety consequence of 0.13 equivalent fatalities expected per year.
- Reliability: PG&E indicates that the impact on reliability from a catastrophic dam failure is negligible because the generation can be replaced quickly "and the homes of customers directly impacted by the inundation would be uninhabitable."
- Environmental: Damage to the environment is accounted for in the financial consequences from estimated remediation costs.
- Financial: PG&E modeled financial impact by aggregating average home prices; number of structures likely to be damaged (estimated 50 percent of structure value to be cost of repair); estimated dam restoration costs; an "infrastructure factor" including estimated damage to roads, powerlines, and other infrastructure in the inundation area; and loss of generation estimates. The aggregated model results indicate a financial impact of dam failure at $8.0 million per year.

Observations

The Dekay-McClelland model for estimating fatalities may be sufficient for an accurate estimate of possible fatalities (and for the basis for injury estimates). However, in the decades since it was first developed and refined, additional models incorporating

[55] Dekay, Michael L., and McClelland, Gary H., "Predicting Loss of Life in Cases of Dam Failure and Flash Floods" 1993.

additional data and using different approaches have been developed.[56] PG&E should evaluate other models to ensure potentially deadly consequences are appropriately estimated and accounted for in the risk model.

Controls and Mitigations

Controls

The 2017-2019 controls included five components to address overall dam safety for three RAMP risk drivers (flood, seepage, and seismic). For this RAMP report, all of those were consolidated into a single Dam Safety Program (DSP) control as shown in table 13-1. These controls are generally compliance-driven and associated with direct regulatory oversight.

TABLE 13-1. Controls (derived from Table 13-5 in the RAMP Report)

Control	2017 RAMP Controls	2020-2022 GRC Controls	2020-2022 RAMP Controls	2023-2026 RAMP Controls
C1 - Hydro Operations Maintenance	X	X	Incorporated in C5	
C2 - Facility Safety Inspections	X	X	Incorporated in C5	
C3 - FERC and DSOD Inspections	X	X	Incorporated in C5	
C4 - Part 12D Inspections and Follow-Up	X	X	Incorporated in C5	
C5 - DSP	X	X	X	X

The Dam Safety Program operates under FERC guidelines and is overseen by PG&E's Dam Safety Advisory Board. The DSP consists of operations and maintenance, facility and safety inspections, FERC and DSOD inspections, and periodic hiring of independent consultants to comprehensively review dam design, condition, and operation.

Federal regulations require PG&E to hire an independent consultant to perform a safety inspection at least every five years to evaluate the condition of the dam and operations, and confirm that its design is suitable for the situation. The inspection process also includes probable failure modes analyses to assess the condition and operation of the dam as well as identify possible weaknesses in dam design and/or monitoring program.

[56] For example: Jonkman, S.N., Vrijling, J.K. & Vrouwenvelder, A.C.W.M. Methods for the estimation of loss of life due to floods: a literature review and a proposal for a new method. Nat Hazards 46, 353–389. and Peng, M., Zhang, L.M. Analysis of human risks due to dam-break floods—part 1: a new model based on Bayesian networks. Nat Hazards 64, 903–933 (2012).

Mitigations

PG&E has identified four mitigation categories, unchanged since the 2017 RAMP Report. These include internal erosion mitigations (previously referred to as seepage mitigation), spillway remediations, seismic retrofits, and low-level outlet (LLO) refurbishments.

Internal erosion mitigation includes repair and restoration of structures, sealing cracks and joints, or adding liner or water barrier partially or fully covering the upstream face of a dam.

Spillway remediation ensures spillways can control flow and avoid flooding risks such as overtopping. PG&E does not propose any new spillway remediation projects between 2023 and 2026. Of the 43 previously approved projects, 22 will continue into 2023-2026.

Seismic retrofitting includes refurbishment and reinforcement of dams and attendant infrastructure to ensure they can withstand anticipated ground motion in the event of an earthquake.

It is important to appropriately maintain LLOs because they are generally used for emptying the impoundment to relieve water loading on a dam and reduce the risk of failure. PG&E projected eight LLO Refurbishments between 2020 and 2023 but does not anticipate starting any LLO refurbishments in the 2023-2026 period.

RSE Calculations

The RSE calculations for the proposed mitigations are displayed in Table 13.2.

TABLE 13-2 Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026

Program	Costs ($000s)	RSE	Risk Reduction
M1 Internal Erosion Mitigations	$22,562	0.37	6.7
M2 Spillway Remediations	$266,550	0.69	139
M3 Seismic Retrofits	$39,500	0.01	0.4
M4 LLO Refurbishments	$1,202	0.14	0.14
Total	$329,813	-	-

Observations

The controls in place are primarily dictated by compliance with regulatory requirements. The mitigations proposed in the RAMP Report are responses to deficiencies identified during inspections, operations and maintenance on each dam and appear to be necessary to maintain safe operating conditions.

Alternatives Analysis

PG&E lists three alternatives in this RAMP Report. Alternative 1 is an internal erosion mitigation through the installation of geomembrane liners. The second and third alternatives are a geosciences engineering and risk research plan and a potential failure mode (PFM) study, respectively. The geosciences engineering and risk research plan and the PFM study are not actually alternatives to the proposed mitigations; rather, they are proposals to better understand risks that could lead to more cost-effective mitigations.

Alternative 1 would install geomembrane liners on all high and significant hazard dams that currently have projects planned to reduce internal erosion by conventional methods, as suggested by the CPUC Public Advocates Office in response to the 2017 RAMP Report. According to PG&E's analysis, the geomembrane liner would cost substantially more than the currently planned mitigations. The RSE of this alternative is lower than the currently proposed mitigations, so it was not proposed.

However, PG&E states the model used for the analysis "does not currently have a degradation curve that would better represent the lifespan of the geomembrane liner (approximately 50 years) versus the lifespan of the original projects (approximately 3-5 years)."

Alternative 2 proposes the Geosciences Engineering and Risk Research Plan, which could help PG&E better quantify the seismic hazards and risk to their dams and attendant facilities. This research would "allow for better prioritization of work and mitigation of existing, but currently unknown hazards and risks and does have the potential to decrease spend through more accurate project designs." This proposal would cost an estimated $200,000 per year for 5 years. PG&E points out that "since this is a research project, the forecasted risk reduction cannot be quantified."

Alternative 3 proposes completing the PMF study. PG&E says they have piloted an updated Probable Maximum Precipitation methodology. They state that "completing this study would improve the accuracy of our model and our understanding of the possible flood impacts," allowing for improved prioritization of mitigations potentially reducing the "costs of future mitigations through more accurate spillway designs." This proposed research is expected to cost $6.5 million over three years. No RSE is provided since the study has not yet been completed.

Observations

Alternatives 2 and 3 are not actual mitigations but could provide guidance for more cost-effective mitigation planning in the future.

Summary of Findings

PG&E has followed the S-MAP Settlement Agreement for analyzing risks and consequences. The tranches are appropriately granular given that each of PG&E's 61 dams classified as high or significant hazards constitutes its own unique tranche.

The proposed mitigations are necessary to comply with state and federal regulations.

Alternatives 2 and 3 warrant consideration for approval in the TY 2023 GRC.

Staff notes that the flood risk model referenced by PG&E was developed in the early 1990s. Since that time, a large body of work has examined and proposed alternatives and revisions to the model.

Recommended solutions to address findings and deficiencies

Staff finds the tranches are appropriate. The controls and proposed mitigations are generally appropriate given that they are in response to identified, site specific safety issues and/or required by FERC and DSOD regulations. Staff recommends that PG&E revisit the model used to estimate fatalities and injuries for floods. While the model referenced by PG&E may be adequate, it was developed in the early 1990. Since that time a large body of work has examined and proposed alternatives and revisions to the model that warrant consideration by PG&E. Because of the relatively high weight given to safety in the MAVF, PG&E should evaluate if more accurate models for estimating fatalities and injuries could provide more accurate estimates.

RAMP Risk (Ch. 14): Real Estate and Facilities

Risk Description

Chapter 14 examines the Real Estate and Facilities Failure Risk. The risk event is described as an event that causes a building, facility, or property within PG&E's service area to be deemed unsafe or inaccessible for operation or occupancy, thereby preventing their use for operational needs. Non-facility related PG&E assets, such as electric and gas transmission and distribution assets, power generation assets, and substations, are considered out of scope of this chapter.

Observations

The Real Estate and Facilities Failure risk was added to PG&E's Enterprise Risk Register in 2019 and is a new risk in the 2020 RAMP.

Bow tie

The risk score for the Real Estate and Facilities Failure Risk is 97, which is relatively low compared to the highest risk scores identified by PG&E in its 2020 RAMP Application.

PG&E forecasts approximately 8.2 risk events per year from 2023-2026, in the absence of proposed mitigations over those same years, and identified five risk drivers in the bow tie analysis: seismic, physical attack, building fire, flood, and landslide.

Observations

Staff finds the bow tie presentation conforms with the Settlement Agreement definition.

Exposure

Exposure to this risk is based on an analysis of 50 representative facilities from a population of approximately 730 facilities managed by Corporate Real Estate Strategy and Services (CRESS). The facilities are a mix of high-, mid-, and low-rise office buildings, service centers, conference centers, and critical facilities in predominately high seismic areas of the state and/or areas of higher employee density.

PG&E's facilities are located in various seismic zones throughout its service territory including relatively high seismic zones in the coastal regions and the greater San Francisco Bay Area and relatively low seismic zones such as the San Joaquin Valley and Sierra Nevada Foothills. All facilities are built to proper building codes and standards at the time of construction, though some facilities are may be at risk of failure during an earthquake greater than the seismic design standard in the building code at the time of construction.

Observations

For other risks discussed in the 2020 PG&E RAMP, PG&E considered the entire population of assets for exposure to the respective risk chapter. In this chapter, PG&E utilized a sample of 50 facilities rather than the population data of all 730 facilities in the FMI database.

Tranches

PG&E took a representative sample of 50 facilities, each a distinct tranche with its own estimated risk score, before grouping them into the four larger tranches based on similar characteristics:

- Group 1- The SFGO Complex: These facilities are PG&E's only high-rise structures, all of which are in San Francisco and serve as PG&E's headquarters. With only four percent exposure, this tranche accounts for 71 percent of the total risk score. The Total Risk Score (TRS) is 68.56. The buildings in this tranche are by far the most vulnerable.
- Group 2 – Mid-to-High Risk Facilities other than SFGO: These facilities are office buildings with more than four stories, referred to as "mid-rise buildings" located in San Jose, San Ramon, and Concord. This tranche only has 10 percent exposure and the TRS is 11.62, which makes up 12 percent of the total risk score.
- Group 3 – Low-Rise Structures: These facilities are typically service centers, office complexes, or conference centers.
- Group 4 – Critical Facilities: These facilities house core computer or customer support operations, such as data centers, grid and gas control centers, emergency operations centers, telecom hubs, and customer contact centers.

Observations

Although PG&E highlights four tranches in the discussion, it does not make a distinction between Groups 3 and 4 when describing the risk exposure and the percent risk by tranche in Table 14-2[57]. Groups 3 and 4 are combined into a tranche called "Low-Rise/Single-Story, representing 43 buildings, or 86 percent the risk exposure. The TRS for this tranche is 16.41, which makes up 17 percent of the total risk score.

Risk Drivers and Associated Frequencies

PG&E identified five risk drivers and their associated 2023 TY baseline frequency:

- Seismic (n=5 of 8 events, or 62 percent)
- Physical Attack (n=2 of 8 events, or 27 percent)
- Building Fire (n<1 of 8 events, or 11 percent)
- Flood (n<1 of 8 events, or one percent)
- Landslide (n<1 of 8 events, or one percent)

[57] PG&E 2020 RAMP, pg. 14-7.

Observations

Seismic, physical attacks, and building fire combine to account for approximately 99 percent of the source events. The seismic risk driver alone accounts for over 99 percent of the total risk score and results in consequence of risk events more severe than other risk drivers. The risk drivers are in line with SPD expectations.

Cross-Cutting Factors

PG&E presents eight cross-cutting factors in the 2020 RAMP. Two cross-cutting factors have been identified as impacting the likelihood of the Real Estate and Facilities Risk: seismic driver and physical attack. Three cross-cutting factors have been identified as impacting the consequence of a risk event: seismic driver, records and information management, and emergency preparedness and response.

Observations

The seismic cross-cutting factor is the most important risk driver affecting both the likelihood and consequence of the risk event.

Consequences

The consequence impacts for this risk are related to safety and finance and are mainly driven by injuries and/or fatalities from seismic damage to PG&E facilities. The bow tie analysis includes five outcomes for this risk event, four of which are seismic-related:

- <u>Seismic Minor</u> (0.05g-0.20g): Accounts for 50 percent of the risk event frequency and 22 percent of the risk.
- <u>Seismic Moderate</u> (0.21g-0.40g): Accounts for eight percent of the risk event frequency and 28 percent of the risk.
- <u>Seismic Strong</u> (0.41g-0.60g): Accounts for two percent of the risk event frequency and 24 percent of the risk.
- <u>Seismic Severe</u> (>0.60g): Accounts for one percent of the risk event frequency and 25 percent of the risk.
- <u>Minor Damage</u>: Accounts for 38 percent of the risk event frequency and 0.2 percent of the risk. This outcome includes the safety and financial consequences of fire, flood, landslides, and physical attacks. Fire, flood, and landslide events did not result in injuries or fatalities because the consequences of these events were non-structural and resulted in minor property damage. Meanwhile, physical attacks are rare and typically consist of incidents of property theft. Therefore, the collective safety and financial consequences from fire, flood, landslides, and physical attacks are minor.

Observations

The financial consequences of even a typical minor seismic event is $1.5 million per event versus $100,000 per non-seismic event.[58]

Controls and Mitigations

PG&E defines controls as currently established measures that modify risk, such as programs required by law or policy, while mitigations are proposed measures designed to reduce one or more of the risk driver frequencies or to modify the consequence outcomes of one or more attributes.

Since the Real Estate and Facilities risk was not included in the 2017 RAMP, PG&E has not previously presented a list of controls and mitigations for this risk. However, PG&E did identify controls and mitigations in the 2020 GRC and expects to continue these programs in the 2020-2026.

Controls include the following:

- C1 – Regional Optimization,
- C2 – Service Center Optimization,
- C3 – CSO Optimization,
- C4 – Facilities Management Preventive Maintenance Program,
- C5 – Site Design Structural and Engineering Reviews,
- C6 – Segregation of Assets,
- C7 – Facility Inspection Program, and
- C8 – Security System Hardening,

Between 2020 and 2022, PG&E will complete several foundational mitigations at a total cost of $2,500,000 that will inform the CRESS multi-year seismic mitigation programs:

- M1 – Seismically Risk Rank Facilities using Tiered System,
- M2 – Identify Seismic Risk Reduction for Multi-Story Buildings,
- M3 – Develop an Updated Seismic Standard,
- M4 – Additional Fire Inspections of Older Facilities, and
- M5 – Refresh/Review of Key Sites Potentially Impacted by Flood, Landslide, or Physical Attack.

PG&E's 2023-2026 mitigation plan will focus on reducing seismic risk across its building portfolio by renovating or relocating structures that do not meet minimum performance criteria:

- M6 – Renovate or Relocate Facilities other than SFGO

[58] PG&E RAMP 2020, "Table 14-4: Risk Event Consequences." pg. 14-12.

The total cost of M6 from 2023-2026 is forecasted to be $80 million, with an RSE score of 0.83 and a risk reduction of 51.14.

Observations

Due to the timing of the PG&E RAMP report completion in May 2020, PG&E did not cover any planned mitigation for SFGO facilities within the high-rise tranche, which accounts for the largest percent risk score despite having the lowest percent exposure. In June 2020, PG&E announced plans to sell the current General Office complex and relocate the SFGO to Oakland.[59]

Alternatives Analysis

PG&E considered two alternative mitigations in Chapter 14.

Alternative Plan 1 (A1) is to Relocate Facilities for Climate Change (other than SFGO). PG&E will consider relocating buildings located in areas of potential sea level rise, and/or employ local or site-specific mitigation efforts to avoid flood impacts to those facilities. A1 was not selected because the risk of flood at PG&E facilities is low and relocation costs are high ($500 million total cost from 2023-2026, for an RSE of 0.13).

Alternative Plan 2 (A2) is to Renovate or Relocate the SFGO. For the 2020 RAMP, PG&E evaluated options related to renovating or replacing the SFGO complex. Despite the potential total cost of approximately $750M total from 2023-2026, A2 would provide an RSE of 1.17. In early June 2020, PG&E announced plans to relocate the SFGO to Oakland and to sell the current General Office complex. The relocation of company headquarters to Oakland is expected to begin in 2022 and be completed in 2023. According to PG&E, "The PG&E move to 300 Lakeside Drive is expected to occur in phases, and PG&E expects to remain in its current location, which includes 77 Beale Street and 245 Market Street, until the move is complete in 2023. PG&E also plans to consolidate two other East Bay satellite office locations—3401 Crow Canyon Road in San Ramon and 1850 Gateway Boulevard in Concord— into the new Oakland headquarters, beginning in 2025. This overall plan will simplify PG&E's Bay Area real estate footprint and lower its operating costs."

Observations

PG&E announced plans to relocate the SFGO building to Oakland. This announcement came after the completion of the 2020 PG&E RAMP, meaning that there is no specific cost analysis, RSE, or risk reduction score for this relocation available for scrutiny by SPD

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[59] PG&E News Release, June 8, 2020. Link last accessed Nov. 23, 2020: <https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20200608_as_part_of_commitment_to_reimagining_pge_for_the_future_company_plans_to_relocate_headquarters_to_oakland_and_will_seek_to_sell_san_francisco_headquarters_complex>

staff. The relocation could increase risks in and around the test year 2023 that may need to be accounted for in the various risk sections of the 2020 RAMP.

Summary of Findings

Tranches

PG&E proposed four tranches by which to evaluate the risks and presumably prioritize mitigations. However, one of the four tranches (Group 4 – Critical Facilities) was not included in the analysis. Instead, it appears that PG&E aggregated Group 3 and Group 4. The only planned mitigations for 2023 through 2026 (M6 and the planned relocation of company headquarters), highlights the lack of focus on facilities in Groups 3 and 4, which contain the highest percentage exposure (but the least vulnerability).

Relocation of the SFGO to Oakland

PG&E made the announcement that it would relocate its headquarters to Oakland from downtown San Francisco. This move is effectively a mitigation of its most vulnerable tranche, Group 1. However, because the move was announced in June, the 2020 RAMP contains no analysis of costs, RSE, or risk reduction related to the upcoming relocation.

Recommended Solutions to Address Findings and Deficiencies

Relocation of the SFGO to Oakland

Without a formal analysis of the relocation of the SFGO buildings to Oakland, staff cannot perform a full review of associated risks and how it might affect the risks carefully analyzed throughout the 2020 RAMP. SPD recommends that PG&E provide a full analysis of such a move, including any risks associated with the transition, and how it might affect the risks analyzed throughout the 2020 RAMP.

RAMP Risk (Ch. 15): Third Party Safety Incident

Risk Description

This chapter examines the risk that members of the public (not including PG&E employees or contractors) are severely injured or killed due to accidents or other interactions with PG&E facilities, equipment, and other property that do not involve the failure of a PG&E asset. These are referred to as third-party safety incidents. Third-party gas dig-in recordable injuries or fatalities, which are included in Gas Operations Loss of Containment Risks, and non-preventable motor vehicle incidents involving third-party interactions, which are included in the Motor Vehicle Safety Incident Risk, are not within the scope of this chapter. The definitions used for serious injury or fatality align with those used by the Division of Occupational Safety and Health (Cal OSHA).

Observations

The safety incidents identified in this chapter have very different types, frequency, likelihood, and exposure risk. The risks and consequences occur under a diverse set of sites and situations. This presents complex risk analysis challenges.

Background and Evolution

This is a new risk added to the PG&E event-based risk register. It is included in the 2020 RAMP based on its risk score. The Third-Party Safety Incident risk places greater emphasis on third-party incidents that do not involve the failure of a PG&E asset and aligns with PG&E’s transition to an event-based risk register with mutually exclusive risks that can be clearly modeled.

Bow tie

The bow tie presents a risk score of 944, the second highest risk score of the 12 risks individually evaluated in the RAMP Report. The bow tie shows a total of 3,417 events per year, with the vast majority composed of car collisions with poles/guy wires, followed by electric contact. The majority of risk drivers occur infrequently, ranging from 2.2 (drowning or other incidents in PG&E managed/owned property) incidents per year to 0.1 (non-pole related motor vehicle incidents) incidents per year.

Observations

The safety incidents covered in this chapter have very different frequencies, likelihood, and exposure risks. Two distinct drivers, D1 – Car Pole/Guy and D2 – Electrical Contact, stand out as the largest contributors to the risk contributing 58 percent and 39 percent of the frequency of events, respectively.

Exposure

To quantify risk exposure of Third-Party Safety Incidents, PG&E's RAMP model uses data from the PG&E Serious Incidents Reports, relevant information from PG&E's Riskmaster database, and PG&E's Electric Incident Report (EIR). The EIR includes any incident which results in a fatality, personal injuries requiring in-patient hospitalization, incidents receiving significant public attention or media coverage, or events resulting in damage to property exceeding $50,000. PG&E Electric Operations experience approximately 3,400 incidents annually, and fewer than one percent result in serious injury or fatality.

Observations

PG&E appropriately based exposure to this risk category based on available data. However, the resultant risks tranches do facilitate a specific, mitigation-oriented analysis. Additionally, the Electric Operations exposure is 99.5% of the total third-party safety incident exposure. Although serious injury or fatality occurs less than one percent for these Electric Operations incidents, this exposure is still a significant average of up to 34 serious injuries or fatalities per year.

Tranches

PG&E identified four tranches:

- Third-party interaction with electric operations assets and job sites;
- Third-party interaction with gas operations assets and job sites;
- Third-party interaction with PG&E managed land and water; and
- Third-party interaction with power generation assets.

Observations

This set of risks presents a unique challenge in the development of tranches due to the wide variety of possible situations and possible interactions with diverse asset types/job sites encompassed by PG&E's large, heterogenous territory. To dispense with this complexity, the tranches are composed of broad, heterogeneous categories of interactions with PG&E's assets.

The tranches used in this chapter are comprised of very different types and frequency of incidents. This is contrary to requirements in the settlement agreement requiring each tranche to have homogenous risk profiles. Risk reductions from mitigations and risk spend efficiencies determined at the tranche level are intended to provide a more granular view of how mitigations will reduce risk.

Analysis of these risks may benefit from further refinement of the tranche categories. For example, the first tranche, third-party interaction with electric operations assets and jobs sites includes a wide variety of situations. The risks and incidents associated with job sites are materially different than risks associated with drivers hitting poles and guy wires.

Risk Drivers and Associated Frequency

PG&E identified nine drivers and five sub-drivers for the Third-Party Safety Incident risk. These include, Car vs. Pole/Guy, Electric Contact, "Others," Job Site (which includes three sub-drivers related to third-party mishaps at work sites), Drowning or Other Incidents at PG&E Owned/Managed Property (which includes two drowning related subdrivers), Slip/Trip/Fall, Suicide, Falling Object/Vegetation, and Motor Vehicle Incident (non-pole related).

Observations

The nine drivers identified appear to address the broad array of third-party interactions with PG&E owned and managed assets that could result in injuries and fatalities.

Cross-cutting factors

The RAMP states that there are no cross-cutting factors that directly impact Third-Party Safety Incident Risk, though Climate Change was considered. During this RAMP period, PG&E will conduct a Climate Vulnerability Assessment (CVA).

Observations

CPUC Staff believes that modeling this risk could be improved with the inclusion of additional cross-cutting factors. For example, elsewhere in the RAMP, PG&E states that system hardening (undergrounding or replacing bare wires with insulated ones) has cross cutting safety benefits with other tranches, such as mitigating electrocutions and wildfire ignition risks. Better marking or moving utility poles from sharp roadside corners not only has a safety benefit to a driver, but also has benefits to customers whose power may be interrupted and may reduce the risk of electrocutions from downed wires. Shallow and Exposed Pipe Replacement and Remediation Programs are also identified, which have cross cutting safety benefits with other tranches. Additionally, risks associated with the physical attack, defined as incidents related to break-ins, vandalism, theft, etc. also pose additional third-party contact risks to both the perpetrators and members of the public. Staff suggests reassessing possible impacts of cross-cutting factors.

Consequences

Third-Party Safety refers to that party's interaction resulting in injury or fatality. PG&E relied on the PG&E Serious Incidents Reports and Electric Incidents Reports from 2012 to 2019 to analyze the safety consequences of Third-Party Safety Incident risk. Third-Party Reliability refers to that party's impact to service reliability. PG&E relied on the PG&E Electric Reliability Reports for customer outage data from 2014 to 2019 to analyze the reliability consequences of the Third-Party Safety Incident risk. The reported customer outage data provides the duration of electric outages by circuit. PG&E did not model financial consequences due to data confidentiality. The consequences of the risk event are shown in Table 15-3 and model attributes are described in Chapter 3, "Risk Modeling and Risk Spend Efficiency."

Observations

Incidents involving third-party serious injuries or fatalities have the potential to become large damage claims. Since PG&E did not consider the financial component in this risk chapter due to confidentiality concerns, the consequences and the risk scores for this risk may be underestimated.

Controls and Mitigations

Controls

Fifteen controls are identified. These include:

- (C1) PG&E Code of Safe Practices (CSP) (Electric, Gas, and Power Generation)
- (C2) Public Awareness Programs (Electric)
- (C3) Public Awareness Program (Bill Inserts) (Electric)
- (C4) Gas Operations Physical Security Controls (Gas)
- (C5) Public Awareness Programs (Gas)
- (C6) Meter Protection Program (Gas)
- (C7) Safe Kids Program – K-8 Safety Education (Electric, Gas, and Power Generation)
- (C8) Hydroelectric FERC License, Public Safety Plans (PSP) (Power Generation)
- (C9) Early Warning Systems, Signage and Alarms (Power Generation)
- (C10) Streetlight Conversions to LED Technology (Electric)
- (C11) PG&E Electric Design Pole Location Requirements (Electric)
- (C12) Visibility Strips on Electric Distribution Poles and Guy Markers (Electric)
- (C13) Anti-Climbing Guard Assemblies for Steel Towers (Electric)
- (C14) Hydro Facility Unusual Water Releases and Water Safety Warning Standard and accompanying procedure (Power Generation)
- (C15) PG&E Dam Safety Surveillance and Monitoring Programs (Power Generation)

Observations

As with other chapters, staff believe that calculating RSE for controls would improve the Commission's, intervenors', and the public's ability to evaluate the benefits of newly proposed mitigations in the TY 2023 GRC.

Mitigations

Seven mitigation are identified. These include:

- (M1 and M2) Shallow and Exposed Pipe Replacement and Remediation Programs. (Gas)
- (M3) Public Outreach, Time-Sensitive Dams, Sudden Failure Assessments (Power Generation)
- (M4) Canals and Waterways Safety Barriers

- (M5) EAPs for all significant and high hazards dams.
- (M6) System Hardening (Electric)
- (M7) 3A and 4C Line Recloser Controller Replacement (Electric)

PG&E's proposed mitigation plan for this risk are M2, M4, and M10. M10 is already included in the Electric Overhead Distribution risk (Ch. 11).

Observations

Given that this chapter explicitly excludes gas dig-in events, Staff are unsure why M1 and M2 are listed as mitigations. It seems like these should be listed as mitigations for another tranche. At the very least, PG&E should explain how M1 and M2 address Chapter 15 risk incidents and the cross-cutting safety benefits with other tranches.

Alternatives Analysis

PG&E proposed two alternative analyses.

Alternative Plan 1: Targeted Third-Party Electric Safety Pilot Program designs and conducts a safety program targeted at regions or circuits that have a high number or rate of third-party contact incidents. Physical locations and type of incidents will be analyzed, and appropriate mitigation options will be considered. Such programs will require close mitigation with municipalities and landowners. Updates on a pilot program will be provided in the 2023 GRC. Potential mitigation options include Eliminate the Hazard; Engineering Control; or Public Awareness.

Alternative Plan 2: Delay Installation of Canals and Waterways Safety Barriers considers delaying the installation of these safety barriers for two years. This alternative was not selected because it would delay important safety work.

Observations

Staff finds the purpose of the Alternative Analysis section unclear. PG&E clearly plans to implement Alternative 1 via a pilot program. This makes it a mitigation measure as opposed to an alternative. Alternative 2 would have delayed installation of Canals and Waterways Safety Barriers, which was rejected by PG&E. There is no explanation of why this is included in the RAMP. What is the potential benefit to delaying this schedule and why was it considered an alternative? Which other alternatives were considered and rejected?

Summary of Findings

Inclusion of third-party safety incidents in the RAMP is a valuable addition. Third-Party Safety Incidents has the second highest Risk score total risk score (944) of those evaluated in the RAMP Report. The facilities, assets, and incident types involved are extremely varied. These incidents involve controlling or mitigating oftentimes unpredictable human behavior.

The risks within the identified tranches in this chapter have very different types, frequency, likelihood, and exposure risk. This is contrary to requirements in the settlement agreement which requires each tranche to have a homogenous risk profile. Risk reductions from mitigations and risk spend efficiencies determined at the tranche level are intended to provide a more granular view of how mitigations will reduce risk. Analysis of these risks would benefit from further refinement of the tranches in this chapter.

Staff notes that physical attack including vandalism, break-ins, and theft could be an important cross-cutting factor.

Recommended solutions to address findings and deficiencies

PG&E should continue to study this risk and refine their analytical approach including further disaggregation of tranches and reassess the exclusion of physical attacks as a cross-cutting factor.

RAMP Risk (Ch. 16): Employee Safety Incident

Risk Description

Chapter 16 examines Employee Safety Incidents. This risk event is described as an event resulting in an Occupational Safety and Health Administration (OSHA)-recordable injury or fatality. If this event was the result of an asset failure it is excluded and outside the scope of this chapter.

Observations

PG&E's 2017 RAMP report identified a need to improve the risk data collected. While Employee Safety risk was included in PG&E's 2017 RAMP;[60] the incident event definition has changed in the PG&E TY2023 RAMP. In 2017, the risk event was defined as a "failure to identify and mitigate occupational exposures that result in an employee OSHA recordable injury/illness or fatality;" in the 2020 RAMP it is defined as an "Employee Safety Incident."

Where the 2017 RAMP definition focused on failures to identify and mitigate occupational exposures – which ultimately resulted in OSHA recordables – the TY2023 RAMP risk event focuses on reportable employee safety incidents.

Bow tie

The risk bow tie represents risk event drivers and their frequencies on the left side of the diagram, risk event in the center, and consequences on the right. Risk Score of the bow tie is calculated by multiplying the LoRE and CoRE values. For Employee Safety Incidents, the risk score is 90, which is ranked eighth of the 12 RAMP risks. PG&E forecasts approximately 603 events per year from 2023 – 2026 in the absence of proposed mitigations over that same time period.

Nine risk drivers were identified in the bow tie analysis, including: bodily reaction and exertion unspecified, typing/key entry/mousing, falls (to floor, walkway, or other surface on same level), three different types of motion strain, repetitive placing (grasping, moving) objects except tools, overexertion in holding (carrying, turning), and an "other" driver category. Outside the bow tie risk driver descriptors, the RAMP Report more specifically states that the drivers for this risk event derive from contact with objects and equipment, exposure to harmful substances or environment, slips or trips, fire and explosion, bodily reaction and exertion, and violence or other injuries by persons or animals.

The risk drivers responsible for the greatest risk are bodily reaction and exertion, at 18 percent of the risk and risk events; typing/key entry/mousing, at nine percent of the risk

[60] PG&E's RAMP Report, Investigation 17-11-003 (Nov. 30, 2017), Chapter 15.

and risk events, and strain in twisting/turning, at eight percent of the risk and risk events.

Observations

Staff finds that while the risk score for Employee Safety Incidents (90) is low relative to the top risk score of Wildfires (24,343), it is only slightly lower than risk scores of Loss of Containment on Gas Distribution Main or Service (99), Real Estate & Facilities Failure (97), nor Contractor Safety incidents (94). These four mid-ranked risk scores, provided in Table 16-1, are all within a risk score of 10.

Given the risk score alone, Employee Safety Incidents may be a low priority; however, it has the fifth highest safety score (86). However, considering the LoRE of 603 events per year, the importance of safety culture (discussed in Chapter 5 of the RAMP report), and both the risk and safety scores, this may be a mid-range priority.

Exposure

Risk exposure is presented as PG&E's annual average of 22,265 employees.

Observations

Approximately 60 percent of PG&E employees are considered office-based, working in PG&E's office locations, and 40 percent primarily work in the field.

Tranches

The Employee Safety Incident risk has two tranches, which are PG&E office-based employees and field employees. The two are distinct groups of employees with similar risk profiles in each tranche.

Office-based employees include but are not limited to managers, engineers and scientists, planners, human resources, finance, and law professionals. These employees are more susceptible to injuries resulting from typing or key entry, strains, slips, trips, and falls.

Field employees include but are not limited to linemen, plant technicians, field analysts, electricians, materials handlers, and troublemen. These employees are more susceptible to injuries from strains from lifting, pulling or pushing, repetitive use of tools, contact with objects and equipment, falls from height, and contact with electrical current.

Of both tranches, approximately 75 percent of the PG&E employee Cal/OSHA recordables in the RAMP model analysis are applicable to field employees and less than one percent of field related Cal/OSHA recordables have resulted in a SIF.

Observations

The office-based employees tranche accounts for the highest percent exposure, 60 percent of the 22,265 employees; however, this tranche accounts for only 7.5 percent of the total risk score. Field employees are the remaining 40 percent of employees and have an approximate 11 times higher total risk score of 82.4 percent.

The choice of tranches is generally logical; however, it lacks homogeneity. Staff recommend PG&E develop more granular tranches with appropriate and uniform risk characteristics. For example, there is a need to further disaggregate field employees by types of duties performed, as an electric lineman working on overhead high voltage lines is likely to have higher injury rates than a gas crew member.

Risk Drivers

The risk drivers for the 2020 RAMP have been further refined from the 2017 RAMP. In the 2017 RAMP, PG&E categorized risk drivers according to Bureau of Labor Statistics Occupational Injury and Illness Classification Manual using PG&E California Occupational Safety and Health Administration (Cal/OSHA)-reportable data. New steps were taken to refine the 2020 RAMP analysis by building on this categorization and including Cal/OSHA-recordable injury claim causes in addition to direct causes, where data is available.

The drivers in the 2020 RAMP use the six injury categories from the 2017 analysis; however, they are now divided into 35 drivers based upon injury claim cause data. Driver categories and their approximate share of PG&E Cal/OSHA-recordable injuries are Contact with Objects and Equipment – 13 percent; Exposure to Harmful Substances or Environment – nine percent; Falls, Slips and Trips – 12 percent; Fire and Explosion – less than one percent; Bodily Reaction and Exertion – 60 percent; and Violence and Other Injuries by Persons or Animal – four percent.

Observations

Staff finds the risk drivers are appropriate given the specified parameters of an Employee Safety Incident event.

Cross-cutting factors

PG&E included four cross-cutting factors as risk drivers: Climate Change, Physical Attack, Records & Information Management (RIM), and Skilled & Qualified Workforce (SQWF). The SQWF accounted for approximately three percent of the driver events, while the other factors had much smaller or unquantifiable impact (i.e. Climate Change). Climate Change, per the 2020 RAMP, does impact RAMP risk; however, data limitations do not allow for the quantification of this impact.

Observations

Staff finds the choice of cross-cutting factors reasonable.

Consequences

This chapter's consequences were based on (1) serious injury according to Cal/OSHA definition or fatality, or (2) financial, as Employee Safety Incident risk includes neither electric nor gas reliability consequences. The consequence scores incorporate safety and financial risk attributes; these scores are dimensionless to allow comparisons between risks and support measurement of risk level changes.

Table 6-4 of the PG&E RAMP Application presents consequences in their natural units per event, which are equivalent fatalities (EF) per event for safety risk, and dollars per event for financial risk. The safety consequence for all risk outcomes is 1.7 EF per year, which corresponds to a safety attribute score of 85.6. Approximately 99 percent of this safety attribute score is due to overexertion and bodily reaction, which is 59 percent of the risk; meanwhile, falls/ slips/ trips is 13 percent, contact with object or equipment is 12 percent, exposure to harmful substances or environments is 10 percent, and violence and other injuries by persons or animals is five percent.

Observations

Chapter 17, which discusses Contractor Safety Incidents, provides a safety risk score of 94 with risk exposure of approximately 25,840 contractors supporting PG&E's work across its lines of business. Employee Safety Incidents has a safety risk score of approximately 86, with risk exposure of PG&E's approximate 22,265 employees. The CoRE in Chapter 17 is a little over three times higher than the CoRE of this chapter and the frequency is about three times lower. Consequences appear to be roughly the same percent frequency if comparing Cal/OSHA recordable items; however, more granular details are not comparable between the two chapters as consequences for contractors are aggregated into one OSHA Recordable item.

Controls and Mitigations

Controls

PG&E's 2017 RAMP had two employee safety risks – Employee Safety and Lack of FFD Program Awareness. These were programmatic in nature to provide infrastructure to further advance PG&E's compliance and safety culture. In the 2020 RAMP, PG&E proposes a series of sixteen controls and six mitigations to address Employee Safety Incident risk, with the FFD controls and mitigations incorporated into the risk.
New controls include SIF incident investigation review, employee wellness, safety and leadership development, training and communication, and enhanced FFD metrics. Enhanced FFD metrics are data tracking metrics that include risk ranking and late or timely reporting to help understand the effectiveness of the FFD program as a control.

Further details on the 16 controls are in Table 16-1. PG&E provides identifying notation of its control programs by prepending them with the letter C.

TABLE 16-1. Controls (derived from Table 16-5 in the RAMP Report)

Control Name and Number	2017 RAMP Controls	2020-2022 GRC Controls	2020-2022 RAMP Controls	2023-2026 RAMP Controls
C1 – PG&E Safety & Health Compliance Standards	X	X	X	X
C2 – CAP	X	X	X	X
C3 – Employee Knowledge & Skills Assessments (Including Academy Training)	X	X	X	X
C4 – Safety Observation Program	X	X	X	X
C5 – Personal Protective Equipment Requirements	X	X	Removed (included with C1)	
C6 – SLD				X
C7 – SIF Incident Investigation Review				X
C7a – SIF Incident Investigation Review				X
C8 – Learning Organization				X
C9 – Benchmarking			Removed as foundational	
C10 – SLD (Leaders in the Field)			X	X
C11 – Enterprise Safety Communication Plan			X	X
C12 – Employee Wellness (formerly 2017 RAMP Risk Category of FFD C2)			X	X
C13 – Training and Communication (formerly 2017 RAMP Risk Category of FFD C1)			X	X
C14 – Enhanced FFD Metrics			X	X
C15 – Benefit Plans & Policy (formerly 2017 RAMP Risk Category of FFD C3)			X	X
C16 – Nurse Care Line			X	X
C17 – Return to Work Task Program			X	X

Mitigations

No new mitigations are proposed for 2023-2026. However, some current mitigations are proposed to continue through 2023-2026 that started in the 2020-2023 time period, including on-site clinics, enhancing SafetyNet use, and what was previously the musculoskeletal disorder (MSD) program. The MSD program has evolved into office, industrial, and vehicle ergonomics programs and an industrial athlete program to reduce discomfort cases and prevent muscle strains and sprains. These proposed MSD programs account for approximately 60 percent of the Cal/OSHA recordables based on historical data.

Risk Spend Efficiency for Controls and Mitigations

PG&E provides proposed mitigations and their calculated RSE values. Each mitigation has a different cost and risk score that affects the RSE. These RSEs are provided as a method to aid decision makers in the GRC to determine whether to approve ratepayer funding for the mitigations, as mitigations offer varying degrees of cost-effective risk reduction.

Observations

PG&E proposes spending approximately 31 percent of its planned funding for programs on the top three RSEs: M1B ESMS Implementation, with an RSE of 12.99; M6d Vehicle Ergonomics Program, with an RSE of 7.11; and M11 On-Site Clinics, with an RSE of 2.21. In addition, PG&E proposes to spend approximately 19 percent on M6a Office Ergonomics, a program that has the lowest RSE and very low Risk Score Reduction, which may be beneficial in reducing worker compensation injuries and injury severity. Mitigations and related RSE data are provided within Table 16-2.

TABLE 16-2. Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026

Program	Expense ($000s)	Risk Score Reduction	Risk Spend Efficiency
M1B ESMS Implementation	3,100	29.6	12.99
M6a Office Ergonomics Program	9,640	2.6	0.37
M6b Industrial Ergonomics Program	4,200	3.5	1.13
M6c Industrial Athlete Program	17,608	8.4	0.64
M6d Vehicle Ergonomics Program	1,133	5.9	7.11
M11 On-Site Clinics	11,757	19	2.21
M17 Mobile Medics	3,749	1.9	0.68

Program	Expense ($000s)	Risk Score Reduction	Risk Spend Efficiency
Total	51,187	-	-

Alternatives Analysis

In addition to PG&E's proposed mitigations, they provide two alternative mitigations. These mitigations are in addition to those already discussed and are evaluated based on the same parameters of forecasted costs, RSEs, and risk reduction scores.

The first alternative (A1) is to implement Industrial Hygiene (IH) Program Compliance Improvements – Phase 2. This would expand the IH Program of Phase 1, which is developing and implementing an overall IH Standard that includes roles and responsibilities for the program. It would then add consultant support, increase staff to expand the program, and provide additional LOB support. PG&E rejected this alternative because it had a lower RSE and risk reduction than other proposed mitigations.

The second alternative (A2) would be to implement Employee Safety Field Inspections for PG&E Work Locations. These inspections would focus on compliance, similar to Contractor Safety Field Inspections, and would likely require additional resources for inspecting PG&E field and office locations. PG&E rejected this alternative due to its low RSE and high cost.

Observations

Staff finds reasonable PG&E's rejections of both alternatives based on low risk reduction and RSE, provided in Table 16-3, and tie-in or similarities to other related programs that are part of the proposed mitigations. M14 – IH Program Compliance Improvements, which is Phase 1 of A1, is shown to be a mitigation only during 2020-2022; however, expanding to Phase 2 is not justified given the cost and RSE impacts. In addition, A2 is said to be similar to Contractor Safety Field Inspections, although A2 is anticipated to require additional resources in order to inspect all PG&E field and office locations.

TABLE 16-3. Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026

Mitigation Plan Components	Expense ($000s)	Risk Score Reduction	Risk Spend Efficiency
Proposed (M1B, M6a-M6d, M11, M17)	51,187	70.9	1.88
Proposed + A1	53,347	71.1	1.81
Proposed + A2	75,017	73.1	1.32

Summary of Findings

For this set of risks, staff find that PG&E has followed the expected risk assessment format, including bow tie analysis, risk driver selection, consequence determination, and risk spend efficiency calculation. Staff is concerned that the tranches provided by PG&E lack sufficient granularity and are generally too large with non-homogenous risk profiles.

Staff note similarities and differences between Chapter 16's Employee Safety Incidents and Chapter 17's Contractor Safety Incidents. Employee Safety Incidents has a risk score of 86 with risk exposure of approximately 22,000 employees, and Contractor Safety Incidents has a risk score of 94 and a risk exposure of approximately 26,000 contractors. CoRE for Employee Safety Incidents are approximately three times lower and the frequency is about three times higher than Contractor Safety Incidents; however, consequences are approximately the same if comparing OSHA recordable items. Finer comparisons cannot be made between the two chapters because consequences for contractors are aggregated into one OSHA Recordable item.

Recommended solutions to address findings and deficiencies

PG&E should revisit their tranches which encompass field personnel. More granular tranches with appropriate and uniform risk characteristics are needed to provide data applicable to different crew types. For example, tranches could look at overhead electric distribution crew members, overhead electric transmission crew members, gas distribution crew members, and gas transmission crew members.

RAMP Risk (Ch. 17): Contractor Safety Incident

Risk Description

This chapter examines the Enterprise Health and Safety -Contractor Safety Incident. A Contractor Safety Incident is any event that results in an Occupational Safety and Health Administration (OSHA) recordable injury or fatality. PG&E contractor recordable injuries that result from failure of an asset is out of scope for this identified risk.

Bow tie

The bow tie score of 94 is the seventh-highest of the 12 RAMP risks and considerably lower than the scores for the top three risks: Wildfire (24,343), Third-Party Safety (944) and Failure of Distribution Overhead Assets (526).

Observations

Staff finds the bow tie presentation conforms with the Settlement Agreement definition.

Exposure

Risk exposure is measured as number of contract employees performing high and medium risk work. The total exposure is based on an annual average of 25,840 contract employees. The risk model includes an annual average of approximately 185 recordable injuries.

Observations

PG&E refined how they measure risk exposure from contractor hours to number of contractors. Also, PG&E's risk drivers have evolved from being categorized according to the Bureau of Labor Statistics Occupational Injury and Illness Classification Manual to being based on OSHA injury classifications and supported by PG&E-specific contractor management data. PG&E's definition of exposure for this chapter is consistent with the S-MAP Settlement agreement stating data can be information derived from, but not limited to, observations, models, records, analysis, or measurements. In this case, PG&E is using industry benchmarks and definitions to identify and measure risk exposure.

Tranches

PG&E identified one tranche for the Contractor Safety Incident risk. This tranche includes high- and medium-risk work activities, described in the PG&E Contractor Safety Program Risk Matrix and aligned to the PG&E Utility Standard, SAFE-3001S.

Observations

Staff finds the identified tranche is a logical disaggregation of work activities as defined in the Settlement Agreement.

Risk Drivers

PG&E identified nine risk drivers based on the OSHA-recordable classifications in ISNetworld (ISN) that are aligned to the contractor's OSHA recordable injuries and illnesses for PG&E work. ISN is a vendor that specializes in contractor safety prequalification and supplier management data.

Observations

Staff finds the risk drivers are appropriate factors that could influence the occurrence of a Risk Event, as defined in the Settlement Agreement.

Risk Driver Frequencies

Each driver is assigned a frequency value in terms of events per year based on the likelihood of risk event per unit of exposure (LoRE,) multiplied by the exposure (number of contractors).

Of the 185 expected annual number of events reportable to OSHA, the top three driver frequencies are (1) Other – 31 percent; (2) Sprains, Strains and Tears – 19 percent; and (3) Cuts and Lacerations – 16 percent. Approximately two percent of the risk events result in a serious injury or fatality.

Observations

Staff finds the risk driver frequencies are appropriate to quantify the risk drivers and the outcomes.

Outcome Frequencies

Outcomes are divided into two categories, (1) serious injury or (2) fatality. Each outcome category has an associated frequency. An OSHA-recordable event occurs 98 percent of the time but does not account for any of the risk consequences. A serious injury or fatality occurs two percent of the time and accounts for 100 percent of the risk consequences.

Observations

Staff finds that the outcomes reflect the effect of the occurrence of a Risk Event, consistent with the Settlement Agreement.

Cross-cutting factors

PG&E included one cross-cutting factor in the analysis, Records Information Management (RIM). PG&E identified RIM as a cross-cutting factor because the risk of not having an effective RIM program may result in the failure to construct, operate and maintain a safe system and may lead to property damage and/or loss of life.

Observations
Staff finds the incorporation of the RIM cross-cutting factor is appropriate.

Consequences
According to the PG&E background material in Chapter 3, consequence outcomes were modeled using Monte-Carlo simulations which feed in to the MAVF risk score calculation. Chapter 17 consequences were based on PG&E Serious Incidents Reports from 2012 through 2019 analyzing the safety consequences of a contractor safety incident. The review and analysis of the data was supported by PG&E Subject Matter Expert (SME) judgement to confirm the initial incident information.

Consequence scores incorporate safety, reliability, and financial risks. The risk scores are dimensionless numbers that are intended to allow comparisons between one risk and another, and to support measurement of risk level changes. Table 17-3 of the PG&E TY2023 RAMP breaks down the consequences into the natural unit equivalent fatalities for the safety risk. The safety consequence for all risk drivers combined is 1.88 equivalent fatalities per year, which corresponds to a safety score of 94.

The highest consequence category is Serious Injury or Fatality with a CoRE of 32.2 and a frequency of occurrence of two percent. The expected natural unit safety outcome for this event is 1.88 equivalent fatalities a year.

Observations
Staff finds that the outcomes are consistent with expectations of risk for contractor safety and follow the Settlement Agreement guidelines.

Controls and Mitigations

Controls
PG&E identified nine controls in its 2017 RAMP that are anticipated to remain in place through 2026. These controls include Contractor Safety Pre-Qualification, Contractor Safety Standard and LOB Contractor Oversight Procedures, and Contractor Post Job Safety Performance Review.

In the TY2023 RAMP, PG&E continues to implement the nine controls included in the 2017 RAMP and adds seven new controls. The new controls include SIF Incident Governance and Oversight, ISN Rapid Growth Tracking and Contractor Evaluations, Enhance Contractor Post-Job Performance Evaluation, and Automated System for Improving Processes through ISN.

Mitigations

PG&E will implement eight new mitigations in the 2020-2022 period. PG&E is proposing two new mitigations between 2023-2026, the continuation of three mitigations started in the 2020-2022 period and shifting five mitigations started in 2020-2022 to controls.

Risk Spend Efficiency for Controls and Mitigations

For each mitigation, PG&E offers a RSE (Risk Spend Efficiency) value. The RSEs are expected to guide decision makers in the General Rate Case on whether to approve ratepayer funding for the proposed mitigations. Some mitigations may offer more cost-effective risk reduction than others.

TABLE 17-1. Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026

Mitigation Name	Cost ($000s)	RSE	Risk Reduction
M11b Work Permits	109	215.9	18.0
M13 Contractor On-Boarding	6,500	3.8	18.0
M14 Contractor Safety Field Inspections	14,960	1.3	14.4
M16 Tracking Contractor Workers	6,005	4.1	18.0
M17 OSHA Programs Training Requirements	591	33.0	14.4
Total	28,164	-	-

PG&E proposes spending over half of its 2023-2026 funds on the Contractor Safety Field Inspections program despite this program having one of the lower RSEs, the most of any mitigation on the lowest RSE activity. However, PG&E argues the Contractor Safety Field Inspections Program is critical because they use it to verify that Contractors are in compliance with OSHA and PG&E safety requirements and adhering to the project specific safety plans approved by PG&E.

Alternatives Analysis

PG&E presents two alternative mitigations, considered in combination with the other proposed mitigations. The evaluation included cost, risk reduction, and RSE.

The first alternative considers eliminating the Contractor Work Management System for tracking contractor work status and crew locations. The Contractor Work Management System supports enhanced oversight, so PG&E rejected this alternative, indicating that it could reduce contractor safety.

The second alternative would expand the Contractor Safety Field Inspections program by increasing the number of PG&E resources assigned to the program. Expanding this program would significantly increase the cost without a commensurate increase in safety risk reduction. PG&E chose not to pursue this alternative due to the high cost.

Observations

In the absence of a suitable alternative to verify contractor compliance with OSHA regulations and PG&E safety plans, staff agree with PG&E's rejection of Alternative 1.

Staff also agrees with the rejection of Alternative 2 due to the increase in costs without a commensurate safety benefit.

Summary of Findings

Staff finds that PG&E has followed the expected risk assessment format including the bow tie analysis, risk driver selection, consequence determination, and risk spend efficiency calculation.

Staff finds that the tranche chosen is a logical disaggregation of a group of assets consistent with the Settlement Agreement.

RAMP Risk (Ch.18): Motor Vehicle Safety Incident

Risk Description

This RAMP chapter examines the Enterprise Health and Safety risk of Motor Vehicle Safety Incident (MVSI). MVSI risk includes any motor vehicle accident involving a PG&E vehicle (or a personal vehicle being operated on company business) resulting in injuries or fatalities to either PG&E employees, the public, and/or property damage. This analysis does not cover off-road vehicles and unique or specialized vehicles included in the Employee Safety Incident risk. There are two risk drivers, non-preventable motor vehicle incident (NPMVI), and preventable motor vehicle incident (PMVI).

Bow tie

The bow tie presents a risk score of 16.6, the tenth-highest of the 12 RAMP risks and considerably lower than the scores for the top three risks, Wildfire (24,343), Third-Party Safety (944) and Failure of Distribution Overhead Assets (526).

Observations

Staff finds the bow tie presentation conforms with the Settlement Agreement definition.

Exposure

Risk exposure is measured as number of driving or riding miles in a PG&E vehicle or vehicle operated on behalf of PG&E. According to PG&E Transportation Services data, the total exposure is based on 141.3 million miles driven per year. The risk model includes an Average Annual Frequency of 914 risk events each year. NPMVI accounts for 57 percent and PMVI accounts for 43 percent.

Observations

The Settlement Agreement defines “exposure” as a “measure that indicates the scope of the risk, e.g., miles of transmission pipeline, number of employees, miles of overhead distribution lines, etc. Exposure defines the context of the risk, i.e., specifies whether the risk is associated with the entire system, or focused on a part of it.” Exposure in this chapter is consistent with the settlement agreement.

Tranches

PG&E identified eight tranches for the 2020 RAMP based on a review of motor vehicle types and weight classes between 2016 and 2019. PG&E owned trucks weighing less than 10,000 pounds and PG&E-owned trucks weighing between 10,000 to 26,000 pounds account for 65 percent of the tranche-level risk for both Preventable and Non-Preventable incidents.

Observations

Staff finds the identified tranche is a logical disaggregation of assets as defined in the Settlement Agreement.

Risk Drivers

PG&E identified seven risk drivers for MVSI classified into two groups, non-preventable and preventable incidents. Non-preventable risk drivers included incidents where a PG&E driver was not at fault. The preventable incidents encompass all accidents where a PG&E driver drove into – or otherwise was at fault for destructive contact with – a stationary or nonstationary vehicle or object.

Observations

Staff finds the risk drivers are appropriate factors that could influence the occurrence of a Risk Event, as defined in the Settlement Agreement.

Risk Driver Frequencies

Each driver is assigned a frequency value in terms of events per year based on the likelihood of risk event per unit of exposure (LoRE,) multiplied by the exposure (miles driven).

Of the 713 expected annual number of events per year, the top driver frequency is Non-Preventable Motor Vehicle Incident (NPMVI) – 73 percent.

Observations

Staff finds the risk driver frequencies are appropriate to quantify the risk drivers and the outcomes.

Outcome Frequencies

Outcomes are divided into two categories, (1) Non-Preventable Motor Vehicle Incident or (2) Preventable Motor Vehicle Incident. Each outcome category has an associated frequency.

Observations

Staff finds that the outcomes reflect the effect of the occurrence of a Risk Event, consistent with the Settlement Agreement.

Cross-cutting factors

PG&E included one cross-cutting factor in the analysis, Records Information Management (RIM). PG&E identified RIM as a cross-cutting factor because the risk of not having an effective RIM program may result in the failure to construct, operate and maintain a safe system and may lead to property damage and/or loss of life.

Observations

Staff finds the incorporation of the RIM cross-cutting factor is appropriate.

Consequences

According to the PG&E background material in Chapter 3, consequence outcomes were modeled using Monte-Carlo simulations. Those consequences feed in to the MAVF risk score calculation. Chapter 18 consequences were based on PG&E Serious Incidents Reports from 2012 through 2019 using Fleet information data. SIF reporting incorporates a defined set of injuries that meets or exceeds OSHA reporting. Incident fault is not defined in the data.

Consequence scores incorporate safety, reliability, and financial risks. The risk scores are dimensionless numbers that are intended to allow comparisons between one risk and another, and to support measurement of risk level changes. Table 18-4 of the PG&E TY2023 RAMP breaks down the consequences into the natural unit equivalent fatalities for the safety risk. The safety consequence for all risk drivers combined is 0.3 equivalent fatalities per year, which corresponds to a safety score of 16.6.

Observations

Staff finds that the outcomes are consistent with expectations of risk for motor vehicle safety and follow the Settlement Agreement guidelines.

PG&E has contracted with the B. John Garrick Institute for the Risk Sciences at UCLA to conduct an assessment that will lead to an update of PG&E's risk analysis so that the MVI risk drivers are expressed as accident causes (distraction, fatigue, etc.) as opposed to accident types.

Controls and Mitigations

Controls

PG&E identified seventeen controls in its 2017 RAMP that are anticipated to remain in place through 2026. These controls include Commercial Driving School, Reasonable Suspicion Supervisor Training, and Commercial Driver's Fatigue Management Procedures. PG&E identifies control programs with the letter C, and mitigation programs with the letter M.

In the TY2023 RAMP, six 2017 RAMP mitigations are now controls.

Mitigations

Prior mitigations included requiring drivers who complete training to affirm they have a valid license for the class of vehicle they will be driving, implementing driver accountability ("How's My Driving") programs, installation and activation of Vehicle

Safety Technology that use GPS systems that provide real-time feedback, and implementing a license and verification plan.

PG&E will implement six new mitigations in the TY2023 RAMP. These include post incident review, utilization of a 360 walk around app designed to increase situational awareness prior to moving the vehicle, and implementation of the UCLA Study and Risk Analysis.

Risk Spend Efficiency for Controls and Mitigations

For each mitigation, PG&E should offer an RSE value to help guide decision makers in the General Rate Case on whether to approve ratepayer funding for the proposed mitigations. PG&E proposes spending $10.3 million on blocking cell phone activity of its drivers with an RSE of .42.

Observations

In the 2023-2026 Proposed Mitigation Plan, PG&E is proposing an engineering control to block phone activity and use while driving. This mitigation is in the initial proposal phase and will be informed by findings from the proposed UCLA analysis.

PG&E did not provide RSEs for the new or modified mitigations in this RAMP Report, with the exception of Cell Phone Activity Blocking.

Alternatives Analysis

Unlike prior chapters, the alternatives proposed in this chapter constitute a plan for future mitigations. These new mitigation proposals are considered in combination with the mitigations described above. Two of these new alternatives, Driver Selection Program and Enhancement to Pool Vehicle Reservation System, are simply expansions of existing controls. The third and fourth alternatives, In-Cab Technology and the Smith Driving Course, are in the initial proposal phase. The initial risk reduction estimates and RSE calculations will be subject to further review with the proposed UCLA analysis.

Observations

Staff supports PG&E's further review of these alternatives.

Summary of Findings

Staff finds that PG&E has followed the expected risk assessment format including the bow tie analysis, risk driver selection, consequence determination, and risk spend efficiency calculation.

Staff finds that the tranche chosen is a logical disaggregation of a group of assets consistent with the Settlement Agreement.

Recommended solutions to address findings and deficiencies

As recommended in previous chapters reviews, staff believes the inclusion of RSE for all existing controls and proposed mitigations would better enable the Commission and intervenors to carry out public interest oversight. This additional information should be provided as PG&E proceeds with the TY 2023 GRC.

Other Safety Risks (Ch. 19)

Risk Description

Chapter 19 discussed 13 safety risks that did not meet the threshold for inclusion in the 2020 RAMP. The S-MAP Settlement Agreement required PG&E to compute a Safety Risk Score (SRS) for each of the 25 risks in its 2019 Corporate Risk Register (CRR)[61] and select the top 40 percent of the CRR risks with an SRS greater than zero. PG&E exceeded this requirement by conducting a full risk assessment for any risk with an SRS within 20 percent of the lowest top 40 percent SRS risk.

Thirteen risks were ultimately excluded from a full analysis in the 2020 RAMP and the Settlement Agreement did not compel the utility to include them in the RAMP Report. However, PG&E did provide some basic information about these thirteen risks in response to feedback at Workshop #3[62], where stakeholders requested that all of the 2019 Corporate Risk Register (CRR) safety risks be discussed in some way in the RAMP. SPD and TURN were especially interested in the safety score assigned to the Nuclear Core Damaging Event risk, concerned by the low safety CoRE value.

PG&E addressed the 13 risks all at once in Chapter 19, organizing the discussion of these risks in alphabetical order rather than descending order of SRS. SPD has reordered the risks discussed in Chapter 19 according to descending SRS, as calculated in Table 4-1[63] of Chapter 4 (see Table 19-1).

TABLE 19-1. Risk Description of Other Safety Risks in the 2019 CRR

Risk	SRS	Description
Failure of Electric Distribution Underground Assets	5	Failure of the distribution underground (UG) assets or lack of remote operation functionality.
LOC on Gas Customer Connected Equipment	3	Loss of containment from a leak or rupture, with or without ignition, on gas customer connected equipment.
Aviation - Helicopter Incident	3	An accident associated with the operation of a rotary wing aircraft during the time any person boards the aircraft and until all persons have disembarked.
LOC at Natural Gas Storage Well or Reservoir	3	Loss of containment with or without an unplanned ignition, at a gas storage well or reservoir.
Aviation - Fixed Wing Incident	2	An accident associated with the operation of fixed wing aircraft during the time any person boards the aircraft and until all persons have disembarked.

[61] The CRR was previously known as the Enterprise Risk Register (ERR).
[62] Workshop #3 held on August 26, 2020.
[63] 2020 PG&E RAMP, pg. 4-3.

Risk	SRS	Description
LOC at Gas Measurement & Control (M&C) or Compression and Processing (C&P) Facilities	2	Failure at a gas M&C or C&P facility resulting in a loss of containment.
Nuclear Core Damaging Event	<0.001	A nuclear reactor core-damaging event with the potential for radiological release at the Diablo Canyon Power Plant (DCPP).
LOC Compressed Natural Gas (CNG) Station	< 0.0001	Loss of containment during operations at a PG&E-owned CNG station.
LOC - LNG/CNG Portable Equipment	< 0.0001	Loss of containment on liquified or compressed natural gas portable equipment during operations.
Failure of Substation Assets	< 0.0001	Failure of substation assets or lack of remote operation functionality.
Failure of Electric Transmission Overhead Assets	< 0.0001	Failure of transmission overhead assets or lack of remote operation functionality.
Failure of Electric Transmission Underground Assets	< 0.0001	Failure of transmission UG assets or lack of remote operational functionality.
Hazardous Materials Release	< 0.0001	Release of hazardous materials (excluding natural gas) by PG&E or by an agent acting on behalf of PG&E or under PG&E's authority.

Observations

The Failure of Electric Distribution Underground Assets has the highest SRS among the other risk categories with a score of five. Seven of the other risks have SRS's lower than 0.001.

Five of the 13 risks included in this chapter are related to natural gas risks; four are related to electric distribution and transmission risks; two are related to aviation risks; one is related to a nuclear risk; and one is related to a hazardous materials risk.

Nuclear Core Damaging Event was a 2017 RAMP risk. PG&E performed an updated risk evaluation in 2019 and determined that this risk is well below the required regulatory threshold of one event for every 10,000 reactor years. However, PG&E continues to conduct seismic evaluations to evaluate the core damaging event risk. And with the impending shutdown of both DCPP Units in 2024 and 2025, a new enterprise risk associated with decommissioning activities is under development.

Because a full analysis of these risks is not required by the Settlement Agreement, these other risks do not include the following: a bowtie analysis, the development of tranches, a discussion of risk drivers, cross-cutting factors, consequences, mitigation costs, risk reduction scores, RSE, and any alternative analysis.

Exposure

Table 19-2 displays the exposure associated with each risk listed in this chapter.

TABLE 19-2. Exposure of Other Safety Risks in the 2019 CRR

Risk	Exposure
Failure of Electric Distribution Underground Assets	Approx. 26,000 circuit miles of distribution underground assets.
LOC on Gas Customer Connected Equipment	Approx. 4.6 million gas meters.
Aviation - Helicopter Incident	Includes 4 heavy lift helicopters.
LOC at Natural Gas Storage Well or Reservoir	As of 2019, includes gas storage assets: 3 storage fields with 111 storage wells; 200 miles of casing and tubing; approx. 14 miles of transmission pipe; 204 subsurface safety valves; and 152 well measurement meters, wellhead separators and flow controls.
Aviation - Fixed Wing Incident	Includes 4 Cessna aircrafts and 1 fixed wing patrol aircraft.
LOC at Gas Measurement & Control (M&C) or Compression and Processing (C&P) Facilities	Includes undefined number of M&C assets and C&P assets installed at 9 compressor stations and 3 underground storage facilities.
Nuclear Core Damaging Event	Diablo Canyon Power Plant (DCPP) Units 1 and 2.
LOC Compressed Natural Gas (CNG) Station	Includes 32 CNG stations.
LOC - LNG/CNG Portable Equipment	Includes trailers that store and transport LNG/CNG, trailers that deliver portable supplies back into the pipeline system or directly to customers, and portable compression equipment used to evacuate pipelines prior to construction work.
Failure of Substation Assets	Includes 945 transmission and distribution substations.
Failure of Electric Transmission Overhead Assets	Approx. 18,000 circuit miles of overhead transmission lines and related equipment.
Failure of Electric Transmission Underground Assets	Pipe type cable, including cable carrier, cross-line polyethylene cable, cable terminations, pumping plant, vaults, splices, low pressure tripping system, and SCADA systems.
Hazardous Materials Release	Includes all the stages of the hazardous materials' lifecycle at PG&E from procurement to disposal. It also includes spills and air release and past events for which PG&E is responsible for remediating.

Controls and Mitigations

Table 19-3 displays the controls and mitigations associated with each risk listed in this chapter. Because an in-depth risk analysis was not required for this section, there is neither a consistent nor complete analysis of the range of risk mitigations. The costs of mitigation, the risk reduction score, and the RSE for the mitigations are not available in this chapter.

TABLE 19-3. Controls and Mitigations of Other Safety Risks in the 2019 CRR

Risk	Risk Controls and Mitigations
Failure of Electric Distribution Underground Assets	Programs: Reliability Related Cable Replacement; Cable Rejuvenation and Testing; Critical Operating Equipment (COE) Cable Replacement; Load Break Oil Rotary (LBOR) Switch Replacement; Underground Patrols and Inspections; Underground Preventive Maintenance and Equipment Repair; Venting Manhole Cover Replacements; and Design Standards Review.
LOC on Gas Customer Connected Equipment	Programs: PG&E conducts a 3-year compliance gas leak survey, along with special leak surveys and leak rechecks, that covers gas distribution pipeline systems, including services, mains and other gas assets. Once a leak is verified and graded, PG&E schedules repair or replacement work to remediate the leak. PG&E also responds to emergencies by replacing or repairing damaged facilities, due to external forces.
Aviation - Helicopter Incident	Regulations: 14 CFR Park 135 Air Carrier Operating Certificate. Programs: Enterprise Corrective Action Program; PG&E's Helicopter Operations Department; Helicopter Operations Field Manual; Flight Risk Assessment; operations briefing; preflight briefings and tailboard safety meetings; and an identification card system. Certifications: 14 CFR Park 135 Air Carrier Operating Certificate; Part 133 External Load Certificate; FAA-certified dispatchers. Technology: Onboard GPS tracking.
LOC at Natural Gas Storage Well or Reservoir	Regulations: CalGEM adopted regulations effective October 1, 2018 that extended the timeline for the baseline casing assessments and the elimination of the single point of failure. The new regulations require this work be completed by 2025. The federal PHMSA issued its final rules in January 2020 that require completing the baseline casing inspections of all the wells by 2027. Programs: M1B - Storage Well Inspection Program.
Aviation - Fixed Wing Incident	Regulations: 14 CFR Park 91 General Aviation; and 14 CFR Park 43 Maintenance and Repair. Programs: Flight Hazard Assessment and Fatigue Risk Management; Simulator Training; and Upset Prevention and Recovery Techniques Training. Certifications: FAA pilots licenses; Flight Operations Manual; FAA-certified dispatches; FAA-certified Aviation Maintenance Technicians or approved FAA contract technicians/maintenance organization; and 14 CFT Part 145 Repair Station Certification. Technology: onboard GPS tracking; computerized maintenance tracking tool.

Risk	Risk Controls and Mitigations
LOC at Gas Measurement & Control (M&C) or Compression and Processing (C&P) Facilities	Programs: *M&C Failure - Release of Gas with Ignition at M&C Facility:* M1B-Critical Documents Program; M2B-Engineering Critical Assessment (ECA) Phase 1; M3B-ECA Phase 2; M4B-Physical Security Upgrades; M5B-SCADA Visibility, Transmission, and Distribution; and M6A-Station Strength Testing. *C&P Failure - Release of Gas with Ignition at Manned Processing Facility*: M1B-Critical Documents Program; M2B-ECA Phase 1; M3B-ECA Phase 2; M4B-Physical Security Upgrades; and M5A-Station Strength Testing.
Nuclear Core Damaging Event	Programs: Beyond Design Basis (BDB) regulatory requirements; seismic, flooding and tsunami studies; portable equipment procurement used in case of a BDB event with extended loss of power; staffing and communication studies to support BDB strategies; upgrade spent fuel pool instrumentation; and upgrade reactor cooling pump seals to prevent loss of reactor coolant. Controls: Maintaining plant systems; operating the facility; plant and system configurations; security from external and internal threats and emergency response; independent oversight and training; and regulatory requirement improvements and ongoing seismic evaluations.
LOC Compressed Natural Gas (CNG) Station	Regulations: Federal and state codes that require periodic maintenance. Programs: Monitoring through regular maintenance and operation, SME knowledge, and processes designed to minimize the likelihood of customers in stations with higher risk vehicles; station capital investment rebuild and replacement work targeted by condition and age.
LOC - LNG/CNG Portable Equipment	Regulations: Federal and state codes that require periodic maintenance. Programs: Monitoring through regular maintenance and operation, SME knowledge, and processes designed to minimize the likelihood of customers in stations with higher risk vehicles; station capital investment rebuild and replacement work targeted by condition and age.
Failure of Substation Assets	Programs: Bus Reliability and Upgrade Program; Projects to reduce risk of substation outages caused by potential failure of gas pipelines collocated with PG&E substations. Controls: Proactive asset replacement; perimeter vegetation clearance; lightning protection; design criteria; drawings and facility markings; damage modeling; grounding systems; substation inspections; intrusion detection; on-site security guards; gas line corrosion protection; fire protection systems; oil containment/spill prevention; community outreach; and outage communications.
Failure of Electric Transmission Overhead Assets	Programs: Enhanced maintenance program (inspections and repairs); Public Safety Power Shutoff (PSPS), asset replacement and retirements; enhanced vegetation management; system configuration design (sectionalizing); seasonal insulator washing; animal abatement; anti-climbing guards; bridging on underbuild; FAA line markers; and tower coating. Controls: Same as the 10 controls in the 2017 RAMP.

Risk	Risk Controls and Mitigations
Failure of Electric Transmission Underground Assets	Programs: Cathodic protection assessments to critical pipe type cable circuits; development of solutions to ensure proper inventory of pipe type cable is available in case of a major disaster; and repairing or replacing transmission UG cables and associated components as part of routine and detailed inspections of UG assets.
Hazardous Materials Release	Controls: Engineering controls such use of proper storage containers and containment; detective controls including remote monitoring and inspections; and administrative controls including handling and storage procedures, spill prevention, control and countermeasure plans, personnel training, and procurement management to reduce or eliminate the use of hazardous substances.

Summary of Findings

PG&E included a brief listing and discussion of other safety risks, i.e., risks that meet the threshold for inclusion in the 2020 RAMP based on the SRS. Their inclusion into Chapter 19 was requested by stakeholders at Workshop #3 on July 30, 2020. SPD and TURN were particularly concerned with the Nuclear Core Damaging Event having such a low SRS and Safety CoRE value.

PG&E re-examined their methodology for estimating the safety consequences of a worst-case scenario nuclear accident at Diablo Canyon and also relied on an analytical study – the DCPP-specific Severe Accident Mitigations Alternatives analysis based on site-specific meteorology, radiation source terms, and population distribution/density. PG&E believes that the Nuclear Core Damaging Event is not underestimating its Safety CoRE value.

Because the Other Safety Risks were not required in the 2020 RAMP under the terms of S-MAP, many of the analytical elements found throughout the other risk chapters are not available in Chapter 19.

Recommended Solutions to Address Findings and Deficiencies

PG&E should consider breaking out the Nuclear Core Damaging Event risk into its own risk chapter and providing a more thorough analysis along the lines of the more significant risks found in the other chapters of the 2020 RAMP, as it was a point of concern for multiple stakeholders.

Cross Cutting Factors (Ch. 20)

Risk Description

This chapter describes the modeling and impacts for eight cross-cutting factors that are applied in the other risk chapters. A cross-cutting factor is a risk driver or consequence modifier that can affect multiple risks. Examples include Climate Change, Cyber Attack, and Seismic activity. Tables 20-1 and 20-2 below give additional details for these factors, including existing controls and proposed mitigations with costs and RSE figures.

PG&E provides tables to show which cross-cutting factors have been applied to which of the twelve primary risks and what impact the factors have on the risk scores.

Observations

Staff notes that it can be difficult to apportion the contributions of cross-cutting factors to each of the primary risks. PG&E has adopted new methods to handle these factors in response to RASA staff comments on the 2017 RAMP Report.

In general, the risk impact of the cross-cutting risks on the total risk scores is small.

Bow tie

A bow tie is not presented because this chapter does not evaluate one of the designated Risk Register risks. Each cross-cutting factor is discussed in detail and mapped to the risk chapters where they appear. However, controls and mitigations for cross-cutting factors are presented, along with RSEs, in Appendix A of this RAMP.

Observations

Presentation of costs and RSEs for mitigation of the cross-cutting factors is useful but may not follow the standard method associated with a bow tie analysis including calculation of the CoRE using the MAVF.

Exposure and Tranches

Risk exposure and tranches for cross-cutting factors are different for each risk chapter that the cross-cutting risks are applied to, as described in those chapters.

Cross-Cutting Factors

The eight factors in the 2020 RAMP are Climate Change, Cyber Attack, Emergency Preparedness and Response (ERP), IT Asset Failure, Physical Attack, Records and Information Management (RIM), Seismic events, and Skilled and Qualified Workforce (SQWF). RIM was a separate risk in the 2017 RAMP but is now treated as a cross-cutting factor in the 2020 RAMP. This list of eight expands on the three items from the 2017

RAMP, and the methods used to evaluate the factors is completely new to the 2020 RAMP.

Each of the factors may impact the likelihood of failure and/or the consequences of one or more risk events. For example, Seismic events are modeled to affect the likelihood of seven of the twelve RAMP risks, while Cyber Attack is only considered to affect Dam Failure. PG&E provides a Table that indicates which factors have been considered in each of the RAMP risks.

Observations
Staff agrees that these risk factors are appropriate cross-cutting topics.

Impact Assessment Modeling

The chapter describes the seven methods that PG&E chose to model risk impacts for the different types of factors on the various risks. Examples describe whether the factor is already present in a risk driver or whether it adds to event frequencies, and whether it escalates driver frequency, or acts as a consequence multiplier.

Observations
The Settlement Agreement does not mention how cross-cutting factors should be modeled, so it is left to the utility to determine how to quantify risk impacts of these factors. Staff expects that determination of risk score and RSE, where applicable, should follow the Settlement Agreement approach.

Controls and Mitigations

Controls
PG&E describes controls for some but not all the cross-cutting factors. No cost or RSE figures are presented for the controls.

TABLE 20-1. Cross-cutting Factor and their Controls

C-C Factor	Controls	Examples
Climate Change	None listed	NA
Cyber Attack	None listed	NA
Emergency Preparedness and Response	12 Programs	• Emergency Operations Plans and Standards for Response • Emergency Response Tech. • EOC/Incident Command System Training • Power Generation Hydro Management Forecasting

C-C Factor	Controls	Examples
IT Asset Failure	None listed	
Physical Attack	3 Programs	• Physical Security • Security Asset and Technology • Corp. Security Control Center
Records and Information Management	None listed	NA
Seismic	None listed	NA
Skilled and Qualified Workforce	None listed	NA

Observations

Staff notes that the likelihood of risk events such as Seismic activity is outside the control of a utility. In those cases, PG&E proposes programs to mitigate the consequences.

Mitigations and Risk Spend Efficiency

The chapter presents mitigations of the cross-cutting factors with their costs and RSE values, summarized in Table 20-2 below. The costs shown are the combined expense and capital forecasted costs for the 2023-2026 rate case period (although costs for 2020-2022 are also presented by PG&E). The aggregate risk reduction is the sum of the reductions for each of the affected risks. The mitigations are aggregated according to PG&E's grouping in the chapter; for example there are six mitigations proposed for Climate Change.

PG&E states that calculation of RSE could not be performed in every case, indicated by "NA" in Table 20-2 below. When RSEs are provided, the reader is directed to the Work Papers for details of how they were determined.

TABLE 20-2. Mitigation Forecasted Costs, RSE, and Risk Reduction, 2023-2026

C-C Factor	Mitigation	Cost ($000s)	RSE	Aggregate Risk Reduction
Climate Change	Six Foundational Mitigations	4,192	NA	NA
Cyber Attack	Four Cyber Mitigations	115,168	0.0002	0.02
Emergency Preparedness and Response	Four Emer. Ops. Ctr. (EOC)Enhancements	6,733	440	2667
Emergency Preparedness and Response	Two Mutual Aid Enhancements	54	14,918	654

C-C Factor	Mitigation	Cost ($000s)	RSE	Aggregate Risk Reduction
Emergency Preparedness and Response	Two Foundational Mitigations	1,289	NA	NA
IT Asset Failure	Five Mitigations	707,743	NA	NA
Physical Attack	Two Mitigations	79,789	<0.01	0.01
Records and Information Management	Nine Mitigations	29,402	6.3	139.3
Seismic	None	NA	NA	NA
Skilled and Qualified Workforce	Enterprise Safety Management System (ESMS)	3,100 (Ch. 16)	12.9	29.6
Skilled and Qualified Workforce	Four Mitigations	NA	NA	NA

Observations

Staff notes these proposed mitigations account for almost $1 billion dollars over the four years 2023-2026. The IT Asset Failure factor alone has $707 million in costs with no RSE presented.

The Emergency mitigations have high RSEs, based on the claimed risk score reductions. Almost all those reductions are from the impact on Wildfire risk: improved emergency response is expected to reduce the consequences of wildfire.

Summary of Findings

Staff is concerned that the details of how risk scores and RSEs attributed to the cross-cutting factors have not been presented clearly. It should be easier to review the risk reduction calculations considering the high cost of the proposed mitigations.

Recommended Solutions to address Finding and Deficiencies

PG&E should present documentation of how the risk scores and RSEs were calculated for the proposed mitigations.

Conclusions

This RAMP is a continuation of PG&E's ongoing effort to apply risk-based decision-making to rate cases that began with PG&E's Test Year 2014 GRC filed in 2012. With each successive rate case, PG&E's risk-based decision-making framework improved risk modeling rigor and data quality. These advances were underpinned by the joint efforts of the Commission and its staff, the large energy utilities, and intervenors through the Safety Model Assessment Proceeding (A.15-05-002 et al).

SPD's evaluation of the PG&E's RAMP Report analyzed the quantitative and probabilistic assessment of PG&E's top 12 safety risks and other risks and scrutinized their plans to mitigate these risks. SPD found that the RAMP Report follows the guidelines with D.16-08-018 for what the RAMP submission should include and generally adhered to the methodologies and new guidelines contained in the S-MAP Settlement Agreement that was approved in D.18-12-014.

Throughout the RAMP Report, SPD found two major areas where improvement is needed, observed some other consistent issues, and made several recommendations.

Critical Issues Where Improvements are Necessary

1. Tranches are not sufficiently granular and do not have homogeneous risk characteristics. This was a recurring observation throughout the RAMP Report in particularly in electrical, third-party contact, and gas risks.

   In various fora and communications PG&E has expressed their commitment to improving granularity and SPD supports continued improvement in this area. PG&E understands the importance of using finer tranches with homogeneous risk profiles to perform risk analysis but cites a lack of "deep understanding of local asset conditions" as an obstacle.[64] PG&E outlines their intent to address these shortfalls by stating "More granular use of tranches is an improvement PG&E will implement in the future. A homogenous risk profile across all assets in a tranche is the goal."[65]

2. RSEs were not provided for controls. As noted elsewhere in this report, this is a critical shortcoming. Understanding the cost effectiveness of previously approved and implemented mitigations (controls) is essential to evaluating proposed mitigations going forward. PG&E informed SPD that RSEs will be provided for controls when PG&E files the TY 2023 GRC.

[64] RAMP Report, pg. 2-4
[65] RAMP Report, pg. 2-16

Other Observations

1. Cost estimates, risk scores, and RSEs are presented as point estimates with no information on the confidence levels of those estimates.
2. In instances where PG&E blended its own historical data with industry-wide data, weights were selected without clear justification. SPD staff suggests applying credibility theory techniques to derive allocation weights to increase the confidence of the combined data.
3. Non-linear scaling functions used to capture risk aversion may produce what TURN characterizes as "irrational" and costly mitigation decisions. SPD finds that this issue is complex and warrants further consideration by the Commission.
4. The 0.5 safety weight in the MAVF may result in very costly mitigation decisions, where the VSL would approach $100 million. PG&E should revisit the MAVF calculations based on intervenor recommendations for scaling and ranging of the outcome natural values. The resulting outcomes would produce a new set of risk scores, risk reductions, and RSEs.
5. Power law distribution may be a better mathematical model to characterize wildfire frequency and consequences. The use of power law distribution functions to model wildfires warrants further consideration.

Parties will be given an opportunity to file comments to PG&E's RAMP Report and SPD's evaluation report. The RAMP filing and comment process shall then form the basis of PG&E's assessment and proposed mitigations for its safety risks in PG&E's TY 2023 GRC filing. A workshop on this evaluation will be held will be held on December 8, 2020.

Summary on Risk Chapters Findings and Recommendations

The following lists the major findings and recommendations from each risk chapter (6-20). In many cases, some common recurring themes emerged, such as the need for finer tranches, the lack of RSEs for controls, and the high safety weight resulting in uneconomic mitigation decisions run through the individual chapters and are already reflected in previous observations. As many of the findings and recommendations should be understood in their proper context, readers are cautioned to refer to the individual chapters for further details.

Ch. 6: Pandemic Risk

1. PG&E should further evaluate the identified risks on human performance identified in their application and explain what efforts they are undertaking to help their employees and contractors endure the societal impacts of the pandemic.
2. PG&E should provide more specific information and examples of possible impacts associated with prolonged deferral of nonessential work and possible impacts on the supply chain of necessary materials. The RAMP application does not include specific examples of either making it difficult to evaluate the gravity or extent of the identified risk.

Ch. 7: Loss of Containment on Gas Transmission Pipeline

1. This chapter does not discuss whether the risk frequencies based on historical PG&E data have been adjusted for the expected risk level at the start of 2023.
2. Proposed mitigations have very low RSEs and high costs compared to existing controls.
3. Proposed mitigations have low RSEs and high costs compared to existing controls.
4. PG&E should revisit the MAVF calculations based on intervenor recommendations for scaling and ranging of the outcome natural values. The resulting outcomes should produce a new set of risk scores, risk reductions, and RSEs.
5. The low RSE and high costs should be thoroughly examined by the Commission and intervenors in the TY 2023 GRC. One element to consider is the relative size of this risk, and the spending adopted to reduce it vs. the higher risk items such as Wildfire risk.
6. PG&E should continue to develop the concept of placing GPS trackers on excavation equipment with the added feature of a built-in alert to the operator if a pipeline is nearby

Ch. 8: Loss of Containment on Gas Distribution Main or Service

1. The number of risers chosen for exposure purposes does not match the reported number of gas customers.
2. Staff recommends that the low RSE and high costs should be thoroughly examined by the Commission and intervenors in the upcoming GRC. The relative size of this risk, and the spending adopted to reduce it, should be compared to higher risk items such as wildfire.
3. Tranches should be chosen to align with groups of assets that have known risk distinctions. PG&E has identified vintage pipe materials as higher risk than non-vintage and has proposed mitigations to address them. It would be logical to create tranches for such material differences.
4. The discrepancy between gas riser exposure and number of gas customers should be explained by PG&E.

Ch. 9: Large Overpressure Event Downstream of Gas Measurement and Control Facility

1. The Risk Spend Effectiveness for mitigation M4, at 0.197, is one of the higher values for the three gas chapters. However, staff review of the Alternative mitigations raises a concern about which regulator stations would be given secondary OPP under the M4 program. It is not clear what PG&E intends to do with stations considered inappropriate for the slam-shut solution.
2. The grouping of M&C stations into tranches of similar function is logical but may not be granular enough to account for different loss-of-containment outcomes considering conditions of the pipelines downstream of the stations.
3. PG&E should clarify what the proposed M4 program will do in the case of regulator stations considered inappropriate for retrofit of slam-shut devices. How many stations will be left out of the mitigation?

4. Staff recommends that the same tranches chosen for the LOC chapters should be applied to this chapter as sub-groupings of the M&C Station tranches to better model outcomes for loss-of-containment events.

Ch. 10: Wildfire

1. The wildfire bow tie risk analysis using the entire service territory for its exposure allows for MARS to be heavily allocated to PG&E's HFTD wildfire risk tranches.
2. PG&E should provide as much granularity as reasonably possible as required by the S-MAP Settlement Agreement particularly for the three highest risk scored HFTD wildfire risk tranches for the TY2023 GRC filing.
3. SPD finds that it is highly unlikely that the two non-Hardened HFTD Distribution tranches with MA Risk scores of 11,411 and 11,811, respectively, have homogenous risk profiles for the 6,929 circuit miles and 18,310 circuit miles within each HFTD Distribution tranche. SPD similarly finds that it is improbable that the HFTD Transmission Tranche with a MA Risk Score of 1,635 has a homogenous risk profile for its 5,526 transmission circuit miles.
4. The highest frequency risk driver in the bow tie analysis for systemwide assets is equipment failure at 38 percent, but in HFTD bow tie analysis, vegetation is the highest frequency risk driver at 45 percent. This exemplifies the importance of the percentage of Associated Risks because for the Wildfire bow tie analysis for PG&E's entire territory, the highest frequency equipment failure risk driver is 27 percent of the associated risks while the second highest frequency risk driver, vegetation, is 44 percent of the associated risks.
5. The highest frequency outcome is Non-RFW small fires at 91 percent of risk events but only 0.12 percent of projected risk outcomes for the TY2023 bow tie baseline. The second highest frequency outcome is RFW small fires at 7.8 percent but only 0.01 percent projected risk outcomes. SPD finds that since these two outcomes for small fires are almost 99 percent of risk events. Hence, PG&E should consider how to focus its MAVF analysis more heavily on conditions that support large, destructive, and catastrophic fires.
6. SPD finds that all controls and all foundational mitigations lack RSE modeling and the results to support controls/foundational mitigations as continuing mitigations and/or to provide insight into effectiveness to reduce wildfire risks.
7. SPD finds that the impacts and relationships between Cross Cutting Mitigations, System Hardening, EVM and Increased Climate Change Risk are more difficult to analyze when PSPS is included in the Wildfire Mitigation Portfolio.
8. SPD finds that REFCL technology is suitable to many of PG&E's operations, has been demonstrated to be effective in Australia, and is being studied by PG&E on an R&D basis with the potential to be proposed for the 2023-2026 GRC cycle.
9. SPD recommends that PG&E should create as much granularity as reasonably possible for the TY2023 GRC in order for MA Risk Scores to reflect risk profiles of its system more appropriately.
10. PG&E should consider dividing their electric distribution assets into smaller tranches for risk analysis.

11. SPD recommends that PG&E should use machine learning and/or artificial intelligence (AI) data analytics techniques to identify more narrow and homogenous risk profiles. PG&E should also consider insights derived from SME proposed initiatives to mitigate wildfire risks, which could help the utility understand how it prioritizes certain assets by common risk characteristics and which would then be classified by its own tranche.
12. SPD recommends that PG&E determine an appropriate solution to model operational failures as a risk driver for its TY2023 GRC. SPD also suggests that PG&E consider if there are related operational risks associated with the size of the utility and whether there is a direct impact on effective and safe operations, particularly for its complicated electrical system over a vast area of the state of California.
13. SPD recommends that PSPS be removed as a mitigation for the TY2023 GRC filing and that if desired, PG&E address PSPS impacts to wildfire MAVF risk analysis in other ways.
14. SPD recommends that M2 be divided into individual initiatives especially large non-related capital initiatives. SPD suggests only programs that are directly related to Covered Conductor or Undergrounding should be included in Risk Reduction and RSE calculations for these individual SH programs.
15. SPD recommends that PGE& should provide MA Risk Reduction Scores, costs and RSEs for individual initiatives, as much as reasonably possible. Additionally, SPD recommends that PG&E provide appropriate mitigations associated with other SPD observations, findings, and recommendations for its wildfire MAVF model changes in its TY2023 GRC.
16. SPD also recommends PG&E provide RSE calculations or estimates for its controls.
17. SPD recommends PG&E include more individual initiatives for RSE analysis to understand the effectiveness and efficiency of each specific control and mitigation.
18. SPD recommends that PG&E reassess how CCF Mitigation will reduce risk year by year especially if they are not capital projects that normally can take longer for implementation.
19. SPD also recommends PG&E provide information on certain wildfire safety mitigation work in FERC proceedings in their GRC filing. SPD recommends that PG&E include FERC Transmission project information, identified in their FERC Stakeholder Transmission Asset Review (STAR) process, and clearly explain its wildfire risk analysis justifying work in non-HFTD and HFTD areas for its transmission assets in its RAMP update in its upcoming TY 2023 GRC filing, even if funding for transmission assets are requested in FERC proceedings.
20. SPD recommends that PG&E’s proposed alternatives and others such as REFCL and Early Fault Detection be considered to address more granular tranches with associated RSE calculated to compare many alternatives for each tranche. This approach will support better investment decision-making.

Ch 11: Failure of Electric Distribution Overhead Assets

1. SPD finds that PG&E should adequately consider industry known safety risks to the public due to the interaction with any failed electric distribution overhead asset including energized wire-down powerlines.
2. The tranches developed by PG&E for the 2020 RAMP are not sufficiently granular to prioritize asset-level risk mitigations.

3. “Other” is a large area of risk that is not well defined or explained, making it difficult – or even impossible – to develop controls and mitigations for risks that are not clearly identified or defined.
4. As noted above, SPD recommends PG&E include risk analysis based on outage and wire-down data including whether the latter is energized versus non-energized. SPD suggests that if historical SIF data is lacking for this risk, then industry data may be an appropriate alternative to estimate risk outcomes.
5. SPD recommends that PG&E develop more granular tranches for its DOH assets.

Ch 12: Failure of Electric Distribution Network Assets

1. The fact that PG&E only has 188 circuit miles of secondary network cable is a major factor for why this is the lowest ranked risk in the RAMP.
2. Although the total number of circuit miles under discussion is small, 70 percent of the circuit miles are grouped into a single tranche. SPD finds that the limited network asset circuit miles in each tranche and the limited exposure, confined to two specific geographic areas, allows for not only evaluating and assessing the risks but also enables prioritization of high failure rate secondary network assets to mitigate this high-risk tranche.
3. M5 holds the lowest projected RSE and Risk Reduction scores even though PG&E believes that its current model understates the risk reduction potential of M5, as the consequences of a failure of any dry-type, high-rise transformers would be much more severe than the failure of a “typical” network transformer.
4. PG&E lists M3-Installation of SCADA as a mitigation, but because the utility considers SCADA to be a “foundational” mitigation, PG&E does not calculate an RSE or a Risk Reduction score. However, PG&E is thinking about modeling the risk associated with SCADA component failure in Alternative Plan 1.
5. PG&E should provide a risk spend efficiency analysis of A3 as a combined program with the condition-based replacement program for the network transformers.
6. Staff recommends that PG&E analyze an alternative plan that combines the program for replacing network transformers based on age alongside the program for replacing network transformers based on condition. PG&E claims that, on average, they replace about 12 transformers per year under the condition-based replacement program alone and would expect to replace the same number from 2023-2026 under the age-based replacement scenario alone. The two programs working together are expected to replace an estimated 12-24 transformers and reduce risk by a greater magnitude than either program alone. Staff suggests that PG&E analyze a program that acts on asset age or condition, instead of only one of the two, and provide assumptions what such a program could cost and what the associated RSE and risk reduction scores could be.

Ch. 13: Large Uncontrolled Water Release

1. The tranches are appropriately granular given that each of PG&E’s 61 dams classified as high or significant hazards constitutes its own unique tranche.
2. The proposed mitigations are necessary to comply with state and federal regulations.

3. Alternatives 2 and 3 warrant consideration for approval in the TY 2023 GRC.
4. The controls and proposed mitigations are generally appropriate given that they are in response to identified, site specific safety issues and/or required by FERC and DSOD regulations.
5. Staff recommends that PG&E revisit the model used to estimate fatalities and injuries for floods. While the model referenced by PG&E may be adequate, it was developed in the early 1990s. Since that time a large body of work has examined and proposed alternatives and revisions to the model that warrant consideration by PG&E.
6. Because of the relatively high weight given to safety in the MAVF, PG&E should evaluate if more accurate models for estimating fatalities and injuries could provide more accurate estimates.

Ch. 14: Real Estate and Facilities

1. PG&E proposed four tranches by which to evaluate the risks and presumably prioritize mitigations. However, one of the four tranches (Group 4 – Critical Facilities) was not included in the analysis. Instead, it appears that PG&E aggregated Group 3 and Group 4. The only planned mitigations for 2023 through 2026 (M6 and the planned relocation of company headquarters), highlights the lack of focus on facilities in Groups 3 and 4, which contain the highest percentage exposure (but the least vulnerability).
2. PG&E made the announcement that it would relocate its headquarters to Oakland from downtown San Francisco. This move is effectively a mitigation of its most vulnerable tranche, Group 1. However, because the move was announced in June, the 2020 RAMP contains no analysis of costs, RSE, or risk reduction related to the upcoming relocation.
3. On the relocation of the SF General Office to Oakland, SPD recommends that PG&E provide a full analysis of such a move, including any risks associated with the transition, and how it might affect the risks analyzed throughout the 2020 RAMP.

Ch. 15: Third Party Safety Incident

1. The risks within the identified tranches in this chapter have very different types, frequency, likelihood, and exposure risk. This is contrary to requirements in the settlement agreement which requires each tranche to have a homogenous risk profile. Analysis of these risks would benefit from further refinement of the tranches in this chapter.
2. PG&E should continue to study this risk and refine their analytical approach including further disaggregation of tranches and reassess the exclusion of physical attacks as a cross-cutting factor.

Ch. 16: Employee Safety Incident

1. Staff is concerned that the tranches provided by PG&E lack sufficient granularity and are generally too large with non-homogenous risk profiles.
2. PG&E should revisit their tranches which encompass field personnel.

Ch. 17: Contractor Safety Incident

SPD has no notable critical observations on this risk chapter and generally find PG&E's risk treatment in this risk chapter acceptable.

Ch. 18: Motor Vehicle Safety Incident

1. Staff finds that the outcomes are consistent with expectations of risk for motor vehicle safety and follow the Settlement Agreement guidelines.
2. For each mitigation, PG&E should offer an RSE value to help guide decision makers in the General Rate Case on whether to approve ratepayer funding for the proposed mitigations.
3. Staff supports PG&E's further review of these alternatives - Driver Selection Program and Enhancement to Pool Vehicle Reservation System
4. Staff finds that the tranche chosen is a logical disaggregation of a group of assets consistent with the Settlement Agreement.

Ch. 19: Other Safety Risks

1. Nuclear Core Damaging Event was a 2017 RAMP risk. PG&E performed an updated risk evaluation in 2019 and determined that this risk is well below the required regulatory threshold of one event for every 10,000 reactor years.
2. PG&E continues to conduct seismic evaluations to evaluate the core damaging event risk. And with the impending shutdown of both DCPP Units in 2024 and 2025, a new enterprise risk associated with decommissioning activities is under development.
3. PG&E should consider breaking out the Nuclear Core Damaging Event risk into its own risk chapter and providing a more thorough analysis along the lines of the more significant risks found in the other chapters of the 2020 RAMP, as it was a point of concern for multiple stakeholders.

Ch. 20 – Cross-Cutting Factors

1. SPD staff notes that it can be difficult to apportion the contributions of cross-cutting factors to each of the primary risks. PG&E has adopted new methods to handle these factors in response to RASA staff comments on the 2017 RAMP Report.
2. Presentation of costs and RSEs for mitigation of the cross-cutting factors is useful but may not follow the standard method associated with a bow tie analysis including calculation of the CoRE using the MAVF.
3. Risk exposure and tranches for cross-cutting factors are different for each risk chapter that the cross-cutting risks are applied to, as described in those chapters.
4. Each of the factors may impact the likelihood of failure and/or the consequences of one or more risk events. For example, Seismic events are modeled to affect the likelihood of seven of the twelve RAMP risks, while Cyber Attack is only considered to affect Dam Failure. PG&E provides a Table that indicates which factors have been considered in each of the RAMP risks.
5. The Settlement Agreement does not mention how cross-cutting factors should be modeled, so it is left to the utility to determine how to quantify risk impacts of these

factors. Staff expects that determination of risk score and RSE, where applicable, should follow the Settlement Agreement approach.

6. Staff notes that the likelihood of risk events such as Seismic activity is outside the control of a utility. In those cases, PG&E proposes programs to mitigate the consequences.
7. Staff notes these proposed mitigations account for almost $1 billion dollars over the four years 2023-2026. The IT Asset Failure factor alone has $707 million in costs with no RSE presented.
8. SPD staff is concerned that the details of how risk scores and RSEs attributed to the cross-cutting factors have not been presented clearly. It should be easier to review the risk reduction calculations considering the high cost of the proposed mitigations.
9. PG&E should present documentation of how the risk scores and RSEs were calculated for the proposed mitigations.

Appendices 1 - 4

APPENDIX 1

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2020 Risk Assessment and Mitigation Phase Report.	Application 20-06-012

INFORMAL COMMENTS ON PACIFIC GAS AND ELECTRIC COMPANY'S SEPTEMBER/OCTOBER 2020 SCENARIO ANALYSES

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November 2, 2020

I. INTRODUCTION

Pursuant to the Safety and Policy Division's (SPD) direction from the October 28, 2020 "scenario analysis" working group meeting, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits these informal comments to Pacific Gas and Electric Company's (PG&E) Risk Assessment and Mitigation Phase (RAMP) proceeding, Application (A.) 20-06-012. Cal Advocates recommends that SPD require the following changes to PG&E's assessment of Public Safety Power Shutoff (PSPS) events:

1. The frequency and impacts of extended power loss should be included as part of a PSPS risk analysis.
2. PSPS risk should be analyzed with greater granularity.
3. PSPS risk should be evaluated as an independent RAMP risk, independent and separate from its use as a wildfire mitigation.

II. CAL ADVOCATES' COMMENTS ON SEPTEMBER/OCTOBER 2020 SCENARIO ANALYSES

The Cal Advocates' Prehearing Conference (PHC) Statement and Protest preliminarily identified several issues the Commission should include within the scope of PG&E's RAMP proceeding.[1] Specifically, the scope should include PG&E's lack of a robust analysis of PSPS events and the significant public safety risks faced by PG&E's customers when PG&E voluntarily chooses to de-energize them. The review of such an analysis (in the RAMP) is necessary to expedite the development of effective general rate case (GRC) PSPS mitigation programs for PG&E's upcoming GRC application, expected to be filed in June 2021.

In response to Cal Advocates' request, PG&E presented a PSPS risk scenario analysis on October 28, 2020. PG&E, however, continues to evaluate PSPS as mitigation measure for wildfire, rather than an independent RAMP risk. PG&E's analysis still does not include a true measurement of the impacts of PSPS events on PG&E's customers. Cal Advocates recognizes the inclusion of negative impacts through the RAMP modeling process, but PSPS risks requires a thorough independent risk analysis.

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[1] See Prehearing Conference Statement of the Public Advocates Office to the Application of Pacific Gas and Electric Company (U39E) to Submit its 2020 Risk Assessment and Mitigation Phase Report (Sept. 24, 2020); Protest of the Public Advocates Office to the Application of Pacific Gas and Electric Company (U39E) to Submit Its 2020 Risk Assessment and Mitigation Phase Report (Aug. 5, 2020).

PG&E's October 28, 2020 scenario analysis presentation claimed no serious injuries due to PSPS events using the OSHA definition of serious injury as one that requires hospitalization. This scenario analysis did not provide an in-depth analysis of other direct and indirect impacts on safety, for example, the loss of lifesaving equipment for medical baseline customers and loss of heating and cooling systems in homes.

In its PHC Statement and subsequent comments, Cal Advocates also referenced the financial impact of the 2019 PSPS events and the testimony by Dr. Michael Wara which estimates the financial impact at upwards of $10 billion.[2] The October 28, 2020 analysis suggests a financial impact of $6 billion based upon Customer Minutes Interrupted (CMI). PG&E did not provide an analysis of the true financial and safety impacts of PSPS events.

1. The frequency and impacts of extended power loss should be included as part of a PSPS risk analysis.

PG&E's PSPS scenario analysis failed to analyze the direct and indirect impacts of longer duration outages compared to shorter outages. Instead, the analysis PG&E presented was based on a CMI reliability metric. The CMI reliability metric does not capture the fact that some customers may incur much greater direct and indirect impacts if they or their community experienced longer duration outages than others or longer restoration times.

For example, PG&E's PSPS website displayed three pockets of customers remaining without power on October 28, 2020 6PM — three days after PG&E began the Sunday, October 25, 2020 PSPS events. If the pockets are small, mitigations targeted towards greatest CMI reduction alone, may fail to prioritize mitigation programs to address pockets of customers who suffer from longer PSPS outages due to location, circuit configuration, or other reasons. The aggregate reduction in CMI from such a mitigation program may be small, but the reduction in duration impacts on those customers could be substantial. A more robust analysis that tracks customer PSPS outage durations could identify such impacts and mitigations.

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[2] Please see U.S. Senate testimony on PSPS impact and costs by Dr. Michael Wara, Director, Climate and Energy Policy Program, Senior Research Scholar, Woods Institute for the Environment, Stanford University, December 19, 2019 Full Committee Hearing to Examine the Impacts of Wildfire on Electric Grid Reliability *available at* https://www.energy.senate.gov/hearings/2019/12/full-committee-hearing-to-examine-the-impacts-of-wildfire-on-electric-grid-reliability ["My best estimate, using the Interruption Cost Estimator (ICE) tool developed by Lawrence Berkeley Laboratory (LBL) indicates that Pacific Gas & Electric (PG&E) PSPS events in 2019 cost customers more than $10 billion…"].

2. PSPS risks should be analyzed with greater granularity.

PG&E's PSPS scenario analysis presented on October 28, 2020 did not analyze the direct or indirect impacts of outages of various durations on different classes of customers, different regional communities, or specific locations. PSPS events place the lives of the disadvantaged, disabled, and elderly at significant risk. Such populations often have greater dependency on electricity for mobility, access, communications, medical, and other support systems.

With more data, and greater granularity, PG&E could develop and prioritize mitigation programs that will address these risks. This would include considerations described above, and gaps that are being uncovered, or have yet to be identified.

For example, at the September 23, 2020 Wildfire Safety Advisory Board[3] (WSAB) meeting, California Community Choice Association (CalCCA) and Community Choice Aggregators (CCAs), shared lessons learned from 2019 PSPS events.[4] CalCCA described a situation where the Auburn City Hall remained powered, but the Police Department lost power during PSPS events:

[3] Wildfire Safety Advisory Board (WSAB). *See*, https://www.cpuc.ca.gov/wsab/.

[4] "CalCCA CCA Resilience Initiatives", September 23, 2020 WSAB meeting. *See*, https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/WSD/CCA%20Presentation%20for%20WSAB%209.23.20.pptx.

> "During the 2019 PSPS events, City Hall had power, but the police department didn't, even though it's right across the alley."
>
> "Pioneer immediately began to work with PG&E to get sectionalizing devices installed to ensure that the police department can stay powered.
>
> And now they're working on similar upgrades for local facilities like the Emergency Broadcast Radio Station."[5]

The loss of essential or emergency services increases the safety risk to the public during wildfire season and PSPS events. By proactively analyzing such risks in a granular fashion, PG&E may better identify, address, and mitigate these risks.

Sonoma Clean Power described how grid analysis uncovered that targeted distribution hardening, could avoid triggering PSPS to a substantial number of customers:

> …in Rincon Valley, in the northeast area of Santa Rosa, they've experienced every PSPS event that's ever occurred in this whole region.
>
> And we did a grid analysis of the switches PG&E had been installed {sic}and we found that by hardening just 0.6 miles of overhead line, about 20,000 customers could remain energized through all the PSPS events.[6]

By devoting resources to conduct a robust granular analysis of PSPS risks, PG&E can develop the data to uncover these direct and indirect impacts of PSPS and then prioritize mitigation programs in its upcoming GRC to expedite reduction of PSPS public safety risk.

3. PSPS risk should be evaluated as an independent RAMP risk.

PG&E's October 15, 2020 comments stated that "[b]ecause a PSPS event is only ever called as a last resort measure to mitigate a potential wildfire, PSPS is not a separate risk on the risk register."[7] While PG&E says it plans to use PSPS as a last resort, PG&E plans to use PSPS as the predominant wildfire risk mitigation for many years to come as depicted in the PG&E waterfall chart below.[8]

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[5] Wildfire Safety Advisory Board (WSAB) meeting, September 23 2020, at 1:06:30. *See*, http://www.adminmonitor.com/ca/cpuc/other/20200923/.

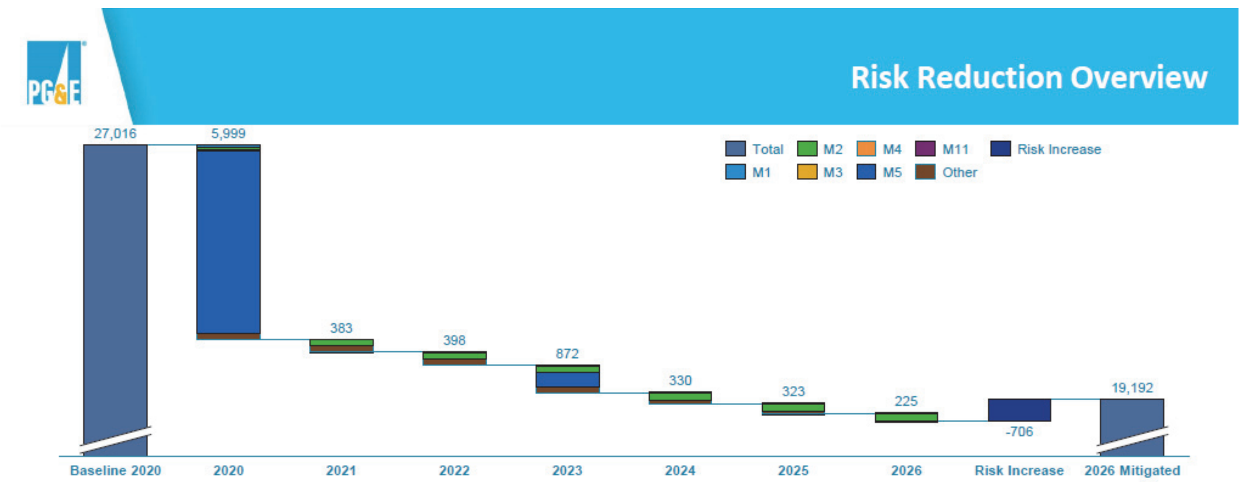
[6] Wildfire Safety Advisory Board (WSAB) meeting, September 23, 2020, at 1:11:30. *See*, http://www.adminmonitor.com/ca/cpuc/other/20200923/.

[7] "Informal Comments of Pacific Gas and Electric Company Following the Risk Assessment Mitigation Phase Application Pre-Hearing Conference" p. 2.

[8] PG&E Wildfire 2020 RAMP Post-Filing Workshop presentation, slide 30.

The PG&E waterfall chart below graphically depicts PG&E's proposed wildfire risk reduction plans from 2020 – 2026.[9] By 2026, PSPS and other wildfire risk mitigation programs are projected to reduce wildfire risk by 7,824 from 27,016 to 19,192.[10] In the waterfall chart, approximately 6,000 of that risk reduction is annually attributed to PSPS, dwarfing the impacts of all other wildfire mitigation programs including covered conductor system hardening over the next rate case period and beyond.

PG&E Waterfall Chart



#	Mitigation Programs[1]	2020	2021	2022	2023	2024	2025	2026
M1	Enhanced Vegetation Management	50	81	114	141	168	196	228
M2	System Hardening	105	276	477	700	931	1161	1394
M3	Non-Exempt Surge Arrester Replacement Program	5	13	14	14	14	14	14
M4	Expulsion Fuse Replacement	0	0	0	1	1	1	1
M5	Public Safety Power Shutoff[2]	5649	5634	5615	6046	6024	5996	5972
M11	Remote Grid	1	1	1	1	1	1	1
Other	Cross-cutting mitigation programs	189	376	559	750	844	936	920
	Risk Increase due to Climate Factors in Baseline	0	0	0	-706	-706	-706	-706
	Total	5999	6382	6780	6946	7276	7599	7824

(1) Excludes Foundational Mitigations.
(2) Includes PSPS's Reliability Impact as reducing overall risk reduction.
(3) Risk reduction by program reflects July 17th errata.

Public

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PG&E's Footnote 2 notes that PSPS risk reduction already subtracts out negative reliability impact resulting from PSPS. However, because PSPS is not evaluated as a risk in

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[9] PG&E Wildfire 2020 RAMP Post-Filing Workshop presentation, slide 30.

[10] Risk reduction would have been greater except for addition of climate factor risk over a portion of the period.

PG&E's October 28, 2020 PSPS scenario analysis presentation, PG&E did not provide detailed data and analysis of PSPS direct and indirect impacts on the public and the associated mitigation programs to reduce those risks. Because PG&E plans to use PSPS as the predominant wildfire risk mitigation now, and for many years to come, this analysis must be expedited. If PG&E will not voluntarily conduct this analysis, then the Commission must order them to do so.

Cal Advocates understands that PG&E attempts to factor in PSPS risk by assigning PSPS a negative reliability score and then uses that to reduce PSPS's wildfire risk reduction score. This approach is inappropriate for measuring PSPS risk mitigation.[11] An objective of the RAMP risk evaluation is to develop and optimize GRC mitigation programs.

PSPS impacts public safety in a much greater way than other typical reliability risk drivers, such as localized line, pole, splice, or transformer failures that most commonly drive the CMI metric. PSPS risk is mitigated by work such as targeted infrastructure improvements, sectionalizing, notification systems, backup power, and customer resource centers. PSPS mitigations can be very different from non-PSPS reliability mitigation programs. Therefore, PG&E should not continue to short-change critical analysis of PSPS and its corresponding mitigations. PG&E must instead appropriately evaluate PSPS as RAMP risk.

At the October 28, 2020 PSPS presentation, PG&E reported that it had no PSPS bodily injury claims for serious injury. PG&E did not provide information on the other bodily injury claims. Restricting PSPS analysis to serious bodily injuries is too high a threshold and too limiting for considering PSPS safety impacts. PG&E must consider all health and safety impacts when evaluating PSPS risks and in developing PSPS mitigation programs.

PG&E reported that it had limited data. PSPS has been a form of wildfire mitigation for years. PG&E should not delay identifying and developing this data. Such analysis and mitigation could potentially have improved PSPS notification and website performance or addressed issues the CCAs described above.

[11] Wildfire mitigation programs, such as vegetation management, system hardening, are very different from PSPS mitigation programs, such as sectionalizing, PSPS notification.

III. CONCLUSION

Cal Advocates requests that PG&E conduct the requested analysis of PG&E's PSPS as a RAMP risk, and if PG&E will not do so, then the SPD and the Commission must order PG&E to do so.

Respectfully submitted,

/s/ SELINA SHEK

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APPENDIX 2

FEITA
Bureau of Excellence

FEITA BUREAU OF EXCELLENCE PRELIMINARY COMMENTS AND SUGGESTED MODIFICATIONS TO PG&E'S 2020 RAMP REPORT AND SCENARIO ANALYSIS

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PRELIMINARY COMMENTS

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I. SUMMARY

The Risk Quantification Framework (MAVF) presented in the RAMP Application[1] that has been developed is overly simplistic, highly subjective, excludes and simplifies risks that result in risk rankings that are unrealistic. PG&E leadership is not qualified or trained to approve or assess the identified risks. Improvement to the risk model will improve safety by identifying more specific areas to focus on and more robust controls, resulting in fewer incidents. The MAVF presented contains foundational errors and flaws that must be rectified prior to the GRC filing. If left unchecked the GRC filing will contain numerous projects that are unjustified.

In these preliminary comments FEITA will discuss some issues and concerns and provide suggestions on how to improve the risk identification, risk ranking and mitigating activities to improve safety and reliability. FEITA hopes that these preliminary comments will aid all parties in their analysis of PG&E's RAMP report.

These comments are preliminary and not complete at this time. Some sections are not complete, discussion points have been captured with bullet points.

II. INTRODUCTION

On June 30, 2020 Pacific Gas and Electric Company (PG&E) submitted their 2020 Risk Assessment and Mitigation Phase Report (RAMP) which provides an assessment of PG&E's top twelve safety risks.[2] The safety of people, assets and the environment are the top priority of FEITA. A full and detailed analysis and review of the risk methodology and efforts to reduce risk presented by PG&E is required and necessary to ensure safe and reliable service.

[1] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company
[2] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company

PG&E held pre-filing workshops that FEITA did not participate in. PG&E also held multiple post-filing workshops, in which FEITA was an active participant. Furthermore, PG&E held numerous coordination meetings with the active parties. FEITA was active in these meetings. During these meetings and workshops FEITA provided direct feedback to PG&E on their RAMP Report and risk analysis. FEITA also provided verbal comments on how to improve the risk analysis. This document captures much of the feedback already provided as well as expands on many ideas that the time constraints of the workshops and meetings did not allow for.

In this document, FEITA will comment on the risk methodology, assumptions and inputs, identify risks that have been omitted and raise questions about the RAMP report as well as provide suggestions to reduce risk(s).

III. RISK METHODOLOGY USED BY PG&E HAS FOUNDATIONAL ERRORS

The risk methodology selected by PG&E sets the foundation of the entire RAMP report. Any errors and poor assumptions will propagate through the risk ranking, producing unrealistic and unreliable results. These erroneous conclusions will result in a General Rate Case filing that has poorly planned mitigation projects to manage unrealistic risks. It is the utmost importance that the risk methodology, assumptions and data sources are of the highest quality to produce realistic results. PG&E's methodology includes human bias and subjectivity. This subjectivity and bias can be used by PG&E to manipulate the input data and what is in scope of the risk to influence the risk scores which will drive projects that they will earn profit on when approved in the General Rate Case.

The errors in the framework and personnel approving and analyzing risk and hazard scenarios must be corrected before the data sources are commented on in depth. It makes little sense to comment on the specific data and factors being used to calculate risk if the risk calculation is wrong. FEITA provides significant and important discussion in this document on the foundational errors of the risk framework. These foundational errors are producing risk calculations that are misleading and easily manipulated by PG&E.

A. SUBJECT MATTER EXPERTISE IS SUBJECTIVE AND NOT RELIABLE IN PG&E'S RAMP APPLICATION

PG&E has attempted to reduce the reliance on subject matter experts (SME) and move toward measured data to calculate risk.[3] FEITA applauds this attempt to move to a less biased system but upon closer look there is still a significant amount of SME input and approval that leads to subjectivity. This results in a risk framework that is biased and can be manipulated by PG&E to suit their General Rate Case, shareholders or however they see fit. As PG&E progresses their framework every effort should be made to remove the opinion of PG&E leadership and SMEs.

The risks that are presented in the 2020 RAMP report are selected from the Corporate Risk Register, which is approved by a Vice President committee.[4] The reliance on a Vice President committee introduces human bias from the very start of the RAMP application. The Vice President committee may approve or not approve identified risks that suit their agenda or to appease shareholders.

The qualifications and competency of the Vice President committee are also in question. The VP committee has positions that have no expertise and do not relate to safety or risk modeling such as: Human Resources Solutions, Corporate Communications, Procurement, Compliance and Ethics and many other positions that are irrelevant to identifying safety risks.[5] A sampling of the education of the

[3] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 1-6
[4] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 4
[5] Data Request response FEITA_001-Q01-11 provided by PG&E on August 21, 2020 in attachment 1

VP committee found that some have degrees[6] in arts, psychology, history, political science, economics, government, all of which not related to this RAMP report and the risks identified. Employees who do not have a technical background should not be in a position to approve risks, they are simply unqualified. An unqualified employee approving risks will result in risks that are unrealistic or exclude credible threats.

PG&E should make additional efforts to reduce relying on 'SME's from the beginning of the risk selection process as well as introduce qualification requirements on the 'SME's that they rely upon to ensure that they actually have expertise in the subject. SME expertise, qualifications and provenance should be proven by PG&E.

B. RISK IDENTIFICATION IS ONLY BASED ON EVENTS THAT HAVE OCCURRED AND IGNORES HAZARDS THAT HAVE NOT RESULTED IN RISK

All of the identified risks in PG&E's 2020 RAMP Application are risks and incidents that have already occurred to PG&E in the past. Every single one. These identified risks ignore every potential event and hazard that could occur but has yet happened. PG&E's identified risks are reactive to the past and are not proactive to prevent potential threats that could result in significant safety, financial and reliability consequences.

[6] Degrees have been listed on both Linkedin.com as well as http://www.pgecorp.com/corp/about-us/officers/company-officers.page. The names VPs that participate on the committee was provided in response to data request RAMP-2020_DR-FEITA_001-Q01

The culture of risk ranking potential events as low and incidents that have occurred as medium or high is also demonstrated in PG&E's Corrective Action Program (CAP). CAP receives hundreds of submissions, by line of business, every day. Ignoring the potential threats or treating them as low risk in CAP shows that PG&E has a cultural deficiency and lack of understanding of what could happen. Risk ranking an incident that has occurred as high is backwards, it already occurred so there is no additional threat.

PG&E should assess all potential threats and analyze them with the same level or rigor as incidents that have occurred. Preventing a potential incident prior to it occurring is orders of magnitude more cost effective. This would also demonstrate a proactive risk reduction culture instead of waiting for an incident then putting in place mitigation strategies to prevent it from happening again. Some examples of potential incidents are discussed below.

C. PG&E IS EXCLUDING MITIGATIONS THAT COULD IMPROVE SAFETY

For each identified risk, PG&E describes the controls and mitigations to control the risk. In many cases PG&E does not provide a complete narrative of all activities they are doing to control a risk, only the high-level ones or only the ones the RAMP team knows about. Furthermore, PG&E has ignored some activities they could do to lower the risk.

Gas pipeline ruptures represent a large risk as demonstrated by the tragedy of San Bruno in 2010. PG&E has recognized that gas pipelines operating at or below 20% of the specified minimum yield stress (SMYS) are "more likely result in leaks, while events on pipelines operating at pressures above 20 percent SMYS have higher possibility to result in ruptures."[7] The two most obvious mitigations strategies are:

1. Lower the operating pressure on the gas pipelines to increase the safety factor
2. For newly installed pipelines design it to operate below 20% SMYS

PG&E does not discuss these mitigations at all in their RAMP Application. Lowering the operating pressure could be accomplished without any costs or projects. It can be done almost immediately

PG&E discussed the safety of operating at a low percentage of SMYS in Chapter 7 and could make new installations inherently safer by installing stronger pipe at nearly no cost to ratepayers. The cost to install stronger pipe during projects represents a marginal cost increase in steel prices, other project costs such as excavation, permitting, engineering, et cetera are unaffected by the yield stress of the pipe. In a Data Request FEITA asked if PG&E has a policy for new installations to be designed and installed to operate at below 20% SMYS. PG&E responded, "No, not all new components PG&E installs operate below 20% SMYS."[8]

Both mitigation strategies would be negligible costs to ratepayers but greatly reduce risk and improve safety. The above example is provided to illustrate that PG&E could introduce additional mitigations to improve safety but has either deliberately ignored to do so or failed to do so from a lack of competence.

For all identified risks PG&E should be open and transparent by show everything and all activities they are doing to reduce risk. They should also cite training

[7] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 7-8
[8] Data Request response FEITA_004-Q01-9 provided by PG&E on August 21, 2020, Answer 09

requirements where administrative controls are referenced. They should also discuss all possible mitigations and not ignore or purposely leave out any.

D. MULTI-ATTRIBUTE VALUE FUNCTION CONCERNS

PG&E's MAVF has many errors and issues that is resulting in erroneous risk ranking and analysis. The errors include attributes that are misleading, units that are unnatural and tranches that are too large.

1. TREATING THE UNITS OF SAFETY, RELIABILITY AND FINANCIAL INDEPENDENTLY IS WRONG

PG&E has independently risk ranked safety risk, financial risk, gas reliability, and electric risk to get a total risk score.[9] PG&E does not consider any relation and influences between safety, reliability and financial. Ranking them independently of each other is easier to model but not realistic. Reliability can impact safety and financial, safety can impact financial and financial impact can result in safety and reliability concerns.

An example of how all units are interrelated is for an extended outage of electricity. For a long outage PG&E would only recognize that there are customer minutes interrupted to calculate the risk score.[10] During a long power outage, businesses and homes would be financially impacted from lost revenue, inability to perform work and spoilage of food. All of these correlates to a financial impact to the ratepayer. Furthermore, a power outage can be life threatening to persons reliant on medical equipment to

[9] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 3

[10] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Table 1 on Page 3

save or sustain their lives. If street lights, traffic signals, cellular networks, gas stations, heating and cooling can also be negatively impacted by an extended outage which also results in safety risks. Gas assets that rely on utility power can result in inability to control equipment or view pressure status.[11] PG&E's model ignores the gas reliability, financial and safety impacts of a long power outage, which is incorrect.

Another example showing how the units are related can be shown by looking at a large gas outage. Again PG&E's model would only look at the number of gas customers affected[12] while ignoring the financial and safety impacts. Natural gas fired power plants represent approximately 18% of PG&E's energy portfolio in 2019.[13] A large outage would result in electrical energy curtailment to customers which carry financial and safety impacts, described in the above paragraph. A large gas outage can also result in stopping industrial customers' production process which carries a large financial impact. Gas outages can affect safety if heating is lost in the home. Gas reliability clearly impacts electric reliability, financial and safety attributes, but PG&E ignores this.

Ignoring the interdependencies of safety, financial and reliability is wrong and results in inaccurate risk modeling. PG&E should be required to accurately risk rank, recognizing that the units of safety, reliability and financial are not independent.

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[11] Many gas facilities that rely on electric power have a battery backup system to power them during an outage. Batteries are not designed for extended outages.

[12] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Table 1 on Page 3

[13] PG&E 2019 Joint Annual Report to Shareholders

2. UNITS OF RELIABILITY ARE MISLEADING AND BIAS ELECTRICAL OUTAGES OVER GAS OUTAGES

It wrong for Electric reliability to be weighted at 20% and gas reliability only at 5%.[14] PG&E states that "This weighting reflects our focus on safety and is consistent with the weighting used by the other large IOUs"[15] This statement is false for the following reasons:

1. This weighting does not reflect PG&E's focus on safety because it ignores all safety impacts from reliability impacts. It is wrong of PG&E to say reliability reflects their focus on safety when no safety impacts of reliability are even considered.

2. The relative unit weight of gas and electric reliability was determined based on financial impact. During Post Filing Workshop #2 on July 30, 2020, FEITA asked PG&E how they determined electric reliability to be four times the weight of gas reliability. PG&E briefly explained that the gas and electric reliability weights were determined based on the equivalent financial impact based on the maximum reliability scale.

   PG&E determined the financial loss of revenue from the maximum ranges. At the maximum unit range, loss of gas to 750,000 gas customers was determined to be four times less than an electric interruption of 4 billion electric customer minutes. Using financial data to determine the importance of reliability is a wrong and again does not reflect PG&E's focus on safety. Also, CMI accounts for aggregated

[14] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Table 1, Page 3
[15] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 1-11

duration, where the total gas customer count ignore duration, the financial figures do not correlate when you ignore duration. Furthermore, if reliability can equate to financial impact it begs the question of why even risk rank reliability at all.

3. Thirdly, Southern California Gas Company and San Diego Gas and Electric Company use a 20% weight for reliability[16]. SoCalGas and SDG&E also use a single reliability index which applies to both gas reliability for gas events and electric reliability for electric events. This contradicts PG&E's statement of being consistent with other large IOUs.

PG&E's reliability model is a secondary financial risk ranking, disguised as reliability. PG&E is totally ignoring the actual risk to ratepayers of reliable service.

PG&E does not have the same number of gas and electric customers[17], the financial impacts of reliability do not corelate. What PG&E is doing regarding their reliability attribute is wrong.

3. RELIABILITY MODEL DISCOUNTS THE TOTAL POSSIBLE RISK SCORE

The reliability model used by PG&E is further incorrect because it will discount the risk score for a gas event due to no electric reliability impact and vice versa for electric events. The risk for any event is determined by

[16] I.19-11-010/011 (cons.), Joint 2019 Risk and Mitigation Phase Report Table 1 Page RAMP-C-6
[17] https://www.pge.com/en_US/about-pge/company-information/profile/profile.page

impacts to safety, electric reliability, gas reliability and financial.[18] For a gas only reliability event, the electric reliability component is zero, leading to the maximum possible risk score being reduced by 20%. PG&E should consider a reliability attribute that combines both gas and electric reliability so that loss of one service is not biasing the risk score. Also, a single reliability index could account for compound events where loss of gas service may result in loss of electric service too.

By risk ranking gas and electric reliability separately PG&E is biasing electric reliability and putting more risk in electric reliability than gas. Presumably PG&E has focused more on electric risks than gas risks because the most recent of PG&E's operating blunders came from the electric side. Biasing electric will aid in the GRC filing to generate more profit from electric projects.

Moving to a single reliability index and not separating gas and electric reliability makes more sense and leads to more realistic risk scoring. Taking into consideration who loses energy supply, and when, is also important to understand the actual risk and impact, not doing so can lead to unrealistic risk scoring and focusing time and money on projects that are the highest importance.

4. UNITS OF RELIABILITY ARE INCONSISTENT AND UNNATURAL

[18] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Table 1 on Page 3

PG&E determined reliability risk of electric outages based on customer minutes of interruption[19] and number of customers affected for gas reliability outages.[20] PG&E is not consistent in their natural units of reliability. Natural units are a requirement of the Settlement Agreement.[21] They are inconsistent because CMI ignores total costumers impacted and the gas unit ignores duration of an outage.

Furthermore, CMI does not account for the outage minutes per customer, it only looks at the aggregated total minutes of an outage, there is more risk the longer the power is out. The electric reliability unit should be based on both total number of customers impacted and duration of each customer outage. The inconsistencies lead to unrealistic risk scores and reliability scores that are incomparable between gas and electric.

The differences in minutes versus number of customers can have a tremendous effect for the customer. The number of gas customers lost may be misleading since duration is missing, gas customers may be out of gas for a minute, a day, a week or even longer but it counts as the same risk to PG&E. In reality, a gas outage of a week is much more significant than a few hours. Similarly, the electric reliability should also incorporate customers lost in addition to duration.

For example, the same CMI applied to different customer counts can result in enormous variations. In the below table an outage of 1.0 billion CMI is examined for various total counts of customers. 1.0 billion CMI only

[19] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 4

[20] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 4

[21] D1812014 Phase 2 Decision Adopting S-MAP Settlement Agreement, Attachment A

represents 25% of PG&E's maximum scale of 4.0 billion CMI. PG&E would rank the following outages the exact same risk:

Customers Affected	CMI	Customer Outage Duration		
		Minutes	Hours	Days
2,000,000	1.0 Billion	500	8.3	0.35
1,000,000	1.0 Billion	1,000	16.7	0.7
100,000	1.0 Billion	10,000	166.7	6.9
50,000	1.0 Billion	20,000	333.3	13.9
15,000	1.0 Billion	66,667	1,111.1	46.3

The above table illustrates why CMI is misleading and does not account for the risk to the customers. The total count and duration must be included. The criticality of customers must also be included (see discussion below). An outage of 46 days to 10,000 customers is not the same risk as eight hours to a large metropolitan area of two million customers.

The gas reliability unit of total customers affected is misleading to the duration. Unlike an electric outage, gas cannot be immediately restored. If there is a gas outage, each customer meter is isolated. To restore service a Gas Service Representative (GSR) is required to visit every customer, perform an inspection and relight the pilot light(s). A GSR visit to every customer takes time so a large outage will take a long time to restore service. PG&E is cognizant of this fact and is probably why they excluded the duration component of the gas reliability unit. PG&E stated in a data request response that an outage of 63,000 customers took approximately one week to restore service.[22] 63,000 customers only represent 8.4% of the maximum scale of 750,000 customers. An outage of 750,000 customers could take 11.9 weeks to restore, assuming the restoration time is directly corelated to the total customers affected.

As illustrated in the below table, the contribution to the risk score for a gas reliability outage is unaffected but the duration. This is unacceptable and highly fictitious by PG&E to consider varying durations of an outage the exact same risk.

Gas customers affected	Time to restore Service	PG&E Risk Rank
100,000	1 Day	Same
100,000	1 Week	Same
100,000	1 Month	Same
100,000	1 Year	Same

The safety and financial impacts of outages have been discussed above. As outage durations increase so does the safety and financial consequences. The CMI count for electric and total customers for gas flagrantly ignore the actual reliability risk to customers. The reliability attribute needs to be based on both total customers affected as well as the outage duration to the customer.

[22] Data Request response FEITA_001-Q01-11 provided by PG&E on August 21, 2020 Question 05

5. CRITICALITY OF CUSTOMERS IS IGNORED

The reliability attribute, weight and range do not account for the fact that some customers loss of supply can have far reaching and detrimental societal effects. If we look at an oil refinery or power plant, which are classified as a single customer, losing gas or electric supply will adversely affect countless more people compared to a single residential house, especially if that home is unoccupied.

If gas and/or electric supply is lost to all bay area petroleum refineries, which would only be five customers, would not even register as a risk to PG&E. Although not a risk to PG&E, the impact felt by the state of California and country from the loss of refining capacity would be unimaginable. Petroleum refineries cannot be instantly started and stopped. It would take days or weeks to return the operation to steady state. Days or weeks without supplying gasoline, diesel, bunker fuel (for ocean vessels) and jet fuel would be felt locally, nationally and internationally. The financial impact would be catastrophic as well as safety would be compromised but PG&E's model ignores the criticality of customers and ignores financial and safety consequences of their reliability risks.

A sudden loss of power to a refinery or other industrial plant or chemical company may lead to secondary consequences such as a loss of containment of a flammable or toxic chemical, fire or explosion due to compromised safety systems that rely on utility services.

If a large company such as Facebook, Apple or Google lost energy for an extended period of time, even though three customers would no rank as a low risk, it could have severe global effects. If SFO or OAK airports lost power it would greatly impact travel. If BART lost power, hundreds of thousands would not be able to get to work or travel home. Power outages can affect gas pumps, leaving people unable to refuel their vehicle fuel tanks. If a farm or orchard is unable to pump water to their crops during critical times it could result in a food shortage at a later time. An extended outage to sanitation and water treatment facilities would be catastrophic.

Each customer is unique and has its own role in society which cannot be discounted. PG&E's model averages out every customer to be an equal risk, but some customers provide essential services to the surrounding area, the consequences of these services must not be discounted.

Averaging each customer to have an equal contribution to overall risk contradicts PG&E's own policies. PG&E defines some customers as core and some as non-core customers, some facilities have even been labeled as 'major' or 'critical'[23] yet they all count the same when risk ranking. If PG&E risk ranks them all the same, then PG&E should not give certain customers or facilities different status, they should treat them all the same. PG&E's recognition that some facilities and customers are more important to operations shows that they are understanding that not all customers are equal. The operations personnel can understand this but the RAMP team ignores this.

Since all customers and facilities are not equal, the risk ranking methodology should be updated to reflect some customers and facilities impacts are much higher risk than others. One more example is Milpitas

[23] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 3-7, 6-1, Data Request response FEITA_001-Q01-11 provided by PG&E on August 21, 2020 Question 05

Gas Terminal, if the Milpitas Terminal was shut down, it would result in nearly the entire San Francisco Bay peninsula and San Jose metropolitan area running out of gas supply. It is clearly a very important piece of infrastructure but the risk ranking does not take this into consideration, just as it does not take into consideration the differences in customers.

6. RELIABILITY RISK AND CONSEQUENCE CAN BE SEASONAL

The weather can impact the severity of consequence as well. If homes or businesses lose heating in the winter or cooling in the summer heat the impact will be greater than in the spring or fall. Weather related deaths are common and are preventable with reliable energy supplies. Heat is one of the leading weather-related killers in the United States, resulting in hundreds of fatalities each year and even more heat-related illnesses.[24] The seasonality of loss of energy supply should be taken into consideration. PG&E should take into consideration the seasonal risks when risk ranking. PG&E is well aware of the risk during fire season, but discounts other seasonal risks and impacts.

Many agricultural customers use gas or electricity in large amounts only during harvest time. Tomato (and other crops) processing plants use large gas flows for boilers only a few weeks a year, the rest of the year the equipment is idle. If a seasonal customer lost their supply during a harvest their entire income or the year would be lost and large food shortages would result.

[24] https://www.weather.gov/safety/heat

PG&E supplies more gas in the winter, which results in higher flows, and higher pressures in the pipeline. The risk of a rupture is higher when pressures are higher. Regulators may fail on demand when operating near the limits. PG&E supplies more electrical power to customers in the summer heat. More load on power lines increases the probability of failure.

The risk to assets and consequences are not uniform throughout the year, but PG&E's model normalizes and averages the risk to be uniform throughout the year. PG&E should update their model to account for the seasonality of risk.

7. POISSON DISTRIBUTION FOR INJURIES IS WRONG

PG&E uses a Poisson distribution, "Poisson distribution for Serious Injuries and Fatalities"[25] which does not provide adequate modeling. PG&E does not explain why they think this is an adequate model. For industrial accidents there is no reliable correlation between injuries and fatalities.[26] [27]

Using any standard distribution is illogical. The only way to estimate fatalities is to accurately model the incident and consequences. For fires, explosions, toxic releases, spills, pipeline ruptures, transformer fires and other incidents the modeling can be done with high accuracy (see QRA section for more details). The consequences of wildfires and large-scale

[25] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 2-15

[26] Conklin, T. 2017. *Workplace Fatalities: Failure to Predict*. PreAccident Media - Santa Fe, New Mexico

[27] The author of this book is a consultant to PG&E and has also provided training to PG&E personnel. The RAMP team should leverage this consultant to model fatalities better and more realistically. PG&E should know this data and not continue to use poor models and distributions.

natural disasters are more difficult to estimate and have many variables. For well understood events accurate modeling should be performed and a Poisson distribution should not be used.

PG&E used incidents such as The San Bruno pipeline incident, Camp Fire, and other incidents to calibrate a log-normal distribution for their risk models.[28] Using multiple incidents to 'calibrate' distributions does not make sense. PG&E is normalizing all incidents of each risk to fit a single model for each risk to apply it. Risk of a gas pipeline rupture or risk of a wildfire cannot be averaged and realistic results expected.

If a gas pipeline ruptures the impact will be influenced by the geography, wind direction, population density (in homes, businesses, lodging, traffic, et cetera), operating pressure, proximity to sources of ignition and many other factors. If there is a flash fire and jet fire or just a jet fire will influence the consequence. A release in a congested area will be more likely to have gas accumulation inside structures that can lead to secondary explosions. Even the pipeline release direction will influence the consequence. A release downward will have greater gas momentum dissipation then an upward release; the resulting jet fire will be much different. A standard model will never be accurate for each incident.

Applying a uniform distribution model to each risk is wrong and leads to erroneous results. Consequences should be modeled for their environment, topography and individual situation. PG&E has the capabilities or can hire consultants to perform modeling work but choses not to.

[28] Data Request response FEITA_003-Q01-06 provided by PG&E on August 19, 2020 Question 04

E. RISK REDUCTION HIERARCHY

When a risk is identified, a definite risk reduction hierarchy strategy to eliminate, control or mitigate the risk should be followed. The following list of controls are provided in order of most effective to least effective with some examples.

1. Eliminate – physically remove the hazard from the workplace
2. Substitution – replace the hazard with a less hazardous item
3. Isolation – physical barriers to keep the hazard away from people or sensitive areas
4. Engineering controls – using control systems, alarms, interlocks, automated emergency shutdown, pressure relieving devices
5. Administrative controls – procedures or training
6. Emergency management - actions taken after an incident occurs

PG&E should identify and label each proposed control and mitigation by what type of risk reduction method it is. They should also place more emphasis and credit on more effective controls (i.e. engineered controls are more effective than administrative controls). PG&E should strive to develop effective controls that address the root cause of the risk and not prioritize mitigations that only address the local causes. Addressing the root causes will eliminate the risk and prevent it from reoccurring, which is obviously much more effective then dealing with repeated risks.

F. MITIGATIONS SHOULD ADDRESS THE ROOT CAUSE AND NOT ADDRESS THE LOCAL ISSUE

PG&E has identified many mitigations and controls, many of them do not address the root causes of the risk. If the root cause is addressed then the current mitigations, which just deal with the issue when it arises, would become unnecessary since the risk would never arise again. It will be much more cost effective for PG&E and customers to address the root causes to eliminate the risk. PG&E may prefer to have many ongoing mitigations and not fully eliminate the risk because they earn more income from ongoing and repeating projects.

Examples of mitigation strategies that do not eliminate the risk are:

1. Public-Safety Power-Shut off (PSPS). PSPS does not address the root cause of equipment failures starting wild fires. PSPS does not prevent or even reduce the likelihood of equipment failure nor does PSPS reduce the reoccurrence of equipment failing. PSPS only "reduces the likelihood of a wildfire event due to equipment failure and vegetation drivers for Red Flag Warning outcomes".[29] PSPS is only applied to address the local issues of equipment failure during hazardous conditions. The root cause of the risk is that the equipment is not properly designed for the site conditions where it has been installed and that it has not been maintained properly. If the root cause is addressed PSPS becomes moot.

2. Enhanced Vegetation Management (EVM). EVM, like PSPS, does not address the root cause of equipment failure. Falling branches do not start wildfires. The root cause of the risk is that the equipment is not properly designed for the site conditions where it has been installed and that it has

[29] Data Request response FEITA_003-Q01-06 provided by PG&E on August 19, 2020 Question 05

not been maintained properly. If the root cause is addressed EVM becomes moot.

3. Gas pipeline catastrophic rupture. To eliminate the risk of a gas pipeline catastrophic rupture an operator can operate the pipeline at less than 20% of the specified minimum yield stress.[30] The root cause of pipeline rupture is operating the pipeline with not enough safety margin between the operating pressure and the yield stress limits of the pipeline. There are two ways to address the root cause here: by installing pipe that is stronger or by reducing the operating pressure (or doing both). Reducing the pressure costs ratepayers nothing, while replacing existing pipelines is very costly.[31] PG&E has failed to address either strategy presented in this example. PG&E does not want to cut into their profits by reducing operating pressure, so they have no even suggested it. PG&E also has stated that "No, not all new components PG&E installs operate below 20% SMYS."[32] Changing the strategy for new installations represents an insignificant cost increase that results in enormous safety improvements.

4. Overpressure events. The gas system is prone to overpressure events, where the operating pressure goes above the maximum allowable operating pressure. Many investigations have concluded that sulfur buildup on the regulation equipment have been the cause. The root of the issue is that the gas supply has sulfur contamination in it. Instead of addressing the gas quality issues to prevent contamination from entering the system, PG&E

[30] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 7-8

[31] Replacing existing pipelines to stronger ones is very costly, however when pipeline replacement projects are planned, increasing the strength of them to be stronger is very marginal.

[32] Data Request response FEITA_004-Q01-9 provided by PG&E on August 21, 2020, Answer 09

only address the sulfur issue at the local level. Sulfur filters are installed on the pilot sense line for pilot operated equipment. This local 'fix' only addresses sulfur from building up on the pilot but does not prevent it from accumulating on the regulator boot, pipeline or customer equipment. Additional issues with gas quality are discussed in detail below.

PG&E and its shareholders greatly benefit from only addressing the local issue and not eliminating the root causes of risk. This is irresponsible toward safety and does not provide reasonable rates to customers. PG&E should prioritize mitigations in order of effectiveness and strive to eliminate the root causes.

IV. MITIGATIONS CAN INTRODUCE HAZARDS AND RISK

PG&E has identified mitigations and controls for each identified risk but has failed to evaluate those mitigations for health, safety, reliability and environmental impacts that they introduce when implemented. PG&E has management of change (MOC) procedures and processes but has not used them to evaluate if the mitigations will be helping or actually introducing risks.

Most all mitigations are well intentioned but a careful analysis must be performed to ensure risk is not inadvertently introduced. In the early 1900s tetraethyllead (TEL or leaded gasoline) was introduced as a safeguard and mitigation against engine knocking and to improve efficiency and fuel economy, all great things. Gasoline companies did not perform a risk analysis to determine if TEL would introduce risk. TEL resulted in worldwide lead contamination, birth defects, cancer and countless other health issues. A guard to protect workers from rotating machinery is a mitigation against injury but it can introduce sharp corners that cause lacerations and even block egress, both of which increase risk. All safeguards must be evaluated for both effectiveness and impacts to safety and operation.

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PG&E is no stranger to introducing safeguards that add risk. After San Bruno Explosion, the Pipeline Safety Enhancement Plan (PSEP) was introduced to implement safety, operational reliability and environmentally focused upgrades to the gas system.[33] As part of PSEP automatic shut off valves were added to the pipelines. If a valve was planned to be added a near a compressor station it could result in severe risk to the compressor(s) which could result in significant reliability concerns. A damaged compressor would take an extended time to repair and be a financial burden. Without compression, a large number of ratepayers would be at risk of undersupply.

To illustrate this, we can look at an example. If an automatic shut off valve was installed on the suction side of Hinkley Compressor Station (HCS)[34] the station would be at increased operational risk after a safety enhancement was completed. HCS operates twelve large, engine driven, reciprocating compressors, which cannot be started and stopped rapidly without mechanical damage. The PSEP shut off valves were planned to be installed as independent systems, without communication with the compressor station control system. This meant it could be shut off without any warning given to the compressor station. Automatic shut off valves, installed in the name of safety, could actually introduce risk to the compressors. If a PSEP valve was shut, while compressors were running, it would cause damage to the station piping and compressors themselves, resulting in significant reliability issues and enormous financial impact. Similarly, if a PSEP valve was installed on the discharge side and rapidly shut the compressors would be in a dead head situation and likely rupture the line. Without analyzing the risk and taking adequate precautions, to interlock the automatic shut off valve with the compressor run status, PG&E could have introduced risk by installing “safety enhancements”. It is very likely that PG&E introduced latent system risk under the veil of improving safety and enhancements.

[33] https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20190308_pge_submits_final_report_on_gas_pipeline_safety_enhancement_plan_to_cpuc

[34] HCS is also home to the groundwater contamination disaster that is a result of a corrosion safeguard (hexavalent chromium) who’s health and environmental impacts were not analyzed. Another example of a mitigation that introduced risk.

Just as in the PSEP projects, in this RAMP PG&E is ignoring any impact to operations and safety of the mitigations and controls.

The above examples are provided to illustrate both the importance of MOC and to show how mitigations, controls and safeguards that are well intentioned can result in impacts and consequences to health, safety, reliability, financial and the environment.

It is imperative that all changes to operations, procedures, processes, technology, equipment, facilities, training, qualifications and personnel are only implemented after a management of change process that includes a risk analysis.

A. PSPS CAN RESULT IN RISK

PG&E considers Public Safety Power Shut Offs (PSPS) as a mitigation against wildfires, not against equipment failure.[35] PSPS does not address the root cause, which is equipment that fails on demand. Instead PSPS is a temporary stop gap to mask PG&E's poor design and maintenance practices of its electrical transmission and distribution system. PSPS is not a sustainable practice. PSPS introduces risk that should be fully addressed and analyzed as long as PSPS is being used.

PG&E blindly implemented the PSPS process to protect their company from negative press and liabilities. If PG&E was not found to be responsible for starting fires and being financially responsible, there is no doubt in this author's mind that PG&E would never willingly implement PSPS. Prior to the recent fires PG&E would have never considered shutting off the power, it was not in their culture.

[35] Data Request response FEITA_003-Q01-06 provided by PG&E on August 19, 2020 Question 05

PSPS put the disadvantaged, disabled and elderly at greater safety risks. Persons who rely on power for life sustaining medical equipment are at mortal danger during a PSPS. Impaired cellular networks, traffic signals and other infrastructure problems also heighten public safety risks. Many industries such as manufacturing, data centers, retail and restaurants are financially impacted. PG&E is ignoring the safety impacts and the enormous lost revenue and operating costs of various industries. PG&E refuses to reimburses ratepayers for spoiled food during a PSPS (which is necessary for life and therefore a safety impact).[36] PG&E will only reimburse food and damages if it is from a severe storm condition.[37] Conveniently, PG&E ignores that PSPS only occur during severe storm conditions.

Not only has PG&E ignored the societal safety, health and financial impacts of PSPS but they have also failed to recognize that as companies and persons try to keep the power during a PSPS, with combustion generators, those generators release toxic materials into the atmosphere. A typical diesel generator exhaust contains more than 40 toxic air contaminants, including a variety of carcinogenic compounds. Combustion of fossil fuels contributes to global climate change, which in turn compounds the weather conditions that contribute to a PSPS.

The risks of PSPS must be fully evaluated to fully understand the risks and hazards that are being introduced.

B. CHAPTER 7 MITIGATION M2, CHAPTER 19 MITIGATION M5A, M6A – STRENGTH TESTING CAN RESULT IN RISK

[36] https://www.pge.com/en_US/residential/outages/current-outages/report-view-an-electric-outage/additional-resources/extended-outage-compensation/extended-outage-compensation.page

[37] https://www.pge.com/en_US/residential/customer-service/help/claims/claims.page

PG&E describes how gas pipelines are strength tested[38], typically using water as a test medium, as a mitigation against pipeline ruptures and loss of containment events. PG&E states that "Strength Testing has the highest RSE score of the proposed mitigations and the second highest risk reduction".[39] PG&E fails to describe the risk involved with strength testing.[40] Nearly all transmission lines are steel[41] which can corrode by oxidizing and rusting.

PG&E also listed internal corrosion as a threat to these steel lines.[42] PG&E has failed to recognize that filling the lines with water can introduce and/or accelerate internal corrosion. Strength testing should be listed as a driver to the internal corrosion threat. Their main mitigation against corrosion is cathodic protection, which only addresses external corrosion, not internal. PG&E has no mitigation for internal corrosion.

Other industries commonly use water to strength test pipes and vessels and have recognized that corrosion can result and is a risk. It is extremely common in other industries for the water used to be treated with anti-corrosion additives. In a data request, FEITA asked PG&E about their water quality standard used for strength

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[38] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Mitigation M-2 is described on Pages 7-23

[39] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 7-29

[40] This section describes the corrosion risk that is introduced when strength testing. Additional risk is to personnel if a strength test fails. Persons and property can be injured from flying debris and high-pressure fluid releases. Testing is normally done with water but can be done with gas pressure too, if a gas is used the risk of flying debris is much higher. The public can also be impacted. For example, on November 6, 2011, PG&E had a strength test failure of a pipeline near I-280 that resulted in a small mud slide (from the released water) and multiple lanes of the freeway had to be shut down for four hours to clean-up.

[41] Data Request response FEITA_004-Q01-09 provided by PG&E on August 18, 2020 Question 05

[42] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Mitigation M-2 is described on Pages 7-9

testing. Their reply was alarming: "PG&E objects to this question on grounds of relevance. The design specification for water used on a strength test is not relevant to PG&E's RAMP filing."[43]

PG&E's lack of understanding on the importance of a water quality standard for water that is introduced into the gas pipelines shows not only their lack of knowledge about corrosion but also shows that they have never evaluated the risks and hazards of their own mitigation.

Water quality is very relevant. PG&E allows water that is pumped from wells, ponds, lakes and rivers to be used as long as it is "clean", but fails to describe what clean is. Upland surface water id typically turbid, has high silt and high organic matter (i.e. fulvic and humic acids)[44], none of which are good to introduce into a gas pipeline.

Any water that is left in place after a strength test will result in localized corrosion (where the water pools). PG&E's RAMP report fails to address how it manages the risk of water that is not removed after a strength test. This is especially worrisome in station strength testing[45] where pigs cannot be run through to push and dry the pipelines. Stations also have more complex piping layouts which are conducive to low spots where water can collect. Collected water can result in localized corrosion whose rates (i.e. mils/year) are orders of magnitude larger than the rest of the system.

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[43] Data Request response FEITA_004-Q01-09 provided by PG&E on August 18, 2020 Question Response to question 8 d

[44] Shreir, L.L, Jarman, R.A., Burstein, G.T., 1994. *Corrosion Volume 1 Metal/Environment Reactions*. Butterworth Heinemann - Oxford, England

[45] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Chapter 19 Mitigation M5A and M6A

PG&E reference the American Society of Mechanical Engineers (ASME) B31.8, Gas Transmission and Distribution Piping Systems, for their piping code.[46] The main issue regarding strength testing is that ASME B31.8 largely ignores water quality for strength testing. ASME B31.8 only prescribes water quality for offshore piping, which is mentioned at appendix A, this section does not apply to PG&E lines. PG&E should look to other codes such as the following to specify water that will not introduce risk when using water as a mitigation strategy:

- ASME B31.1
- ASME B31.3
- ASME PCC2
- API 1110
- API 510
- API 570
- EIL 6314-00-16-71-SP-55
- SAES-A-A007
- EEMUA 168

PG&E did not mention any corrosion inhibitors used in strength testing water or commissioning treatment.[47] PG&E should treat the pipeline with a corrosion inhibitor immediately prior to re-commissioning new or existing lines. This will further improve the mitigation to reduce loss of containment events.

[46] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Pages 7-5, 9-11

[47] Data Request response FEITA_004-Q01-09 provided by PG&E on August 18, 2020 Question Response to question 8 d

Because PG&E does not specify the quality of water (i.e. chloride concentration[48], total dissolved solids, pH, dissolved oxygen, total organic matter, et cetera) undesirable constituents will be present in the water that they use to strength test their pipelines. The predominant cathodic reactions accompanying corrosion processes in aqueous solutions are hydrogen evolution and dissolved oxygen reduction.[49] Deoxygenation therefor offers an important means of corrosion control.

The undesirable constituents will result in internal corrosion, leaving the pipe with less strength after it is drained and dried than it was just tested for. Over time the very process to verify the pipeline integrity will result in a weaker pipeline, which are more prone to failure. The mitigation here will result in greater risk of loss of containment of high-pressure natural gas.

To make the strength testing mitigation more robust PG&E should create a water quality standard, enforce its use, passivate pipe when first installed. PG&E should also record and measure dissolved metals before and after the test to see if any iron from the steel was dissolved into the water during the test. This will result in a safeguard that is introducing significantly less risk.

C. PIGGING OF PIPELINES CAN RESULT IN RISK

In-Line Inspection or pigging is identified as control C8 for Transmission Loss of Containment.[50] Pigging also occurs before and after a strength test. A strength test

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[48] Chloride concentration of 50 ppm or less is recommended when strength testing austenitic stainless steels

[49] Shreir, L.L, Jarman, R.A., Burstein, G.T., 1994. *Corrosion Volume 2 Corrosion Control*. Butterworth Heinemann - Oxford, England. Chapter 17 at 72.

[50] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 7-20

can require cleaning and drying pigs, which can be wire bushed pigs, urethane pigs, foam pigs all of which can negatively impact the steel.

Running any pig through the pipeline can result in erosion-corrosion or velocity-assisted corrosion. Erosion-corrosion is influenced by many factors, chemistry, flow, temperature and whether one or two phases (solid, liquid or gas phases) are present. This will be more pronounced with wire brush or foam 'drying' pigs. The pigs create and push particulate matter through the pipe, similar to running sandpaper along the inside of the pipeline.

As the pig runs down the pipeline, along with the debris it is creating or pushing, the surface layer of the pipeline may be eroded. This will then expose virgin steel, which corrodes much faster than steel that already has a surface layer of corrosion existing. The pigging results in decreased integrity of the pipeline.

Another risk that PG&E is not mentioning is that when pigs are used (including ILI), lubricants are sometimes added to aid the pig travel or control its velocity to a prescribed rate. Lubricants commonly used on gas pipelines include diesel fuel or methanol. In many cases the volume of liquid injected is always much higher than what is recovered, meaning liquids remain in the pipe after pigging. These liquids can cause filters to be clogged, overpressure events, regulation to fail, reliability concerns or even exit the system through customer equipment.

PG&E is relying on pigging, "is the most reliable pipeline integrity assessment tool currently available to a natural gas pipeline operator"[51] as a control and mitigation

[51] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 7-20

against loss of containment events but again fails to address that the safety measure and mitigation introduces risk.

D. MITIGATION M1 FOR WILDFIRE AND FAILURE OF DISTRIBUTION OVERHEAD ASSETS CAN RESULT IN RISK

Enhanced vegetation management (EVM) is a mitigation against wildfires.[52] EVM, like PSPS, does not address the root cause of wildfire ignitions, equipment failures. EVM is another example of a mitigation that masks the real issue, PG&E has not designed equipment to withstand the forces for their environment. PG&E does not describe that EVM can also result in risk and latent failures. When vegetation is cut near power lines the cut branches, logs and tools can fall and impact the lines. The author of these comments has discussed vegetation management with contractors that PG&E uses. The EVM contractors have stated that it is very common for large branches to bounce off the power lines. They have even reported that falling objects have caused lines to break and had to be repaired.

EVM contractors are arborists, not engineers, they do not have the technical expertise to calculate the forces generated by falling objects and determine if those forces are over stressing the lines. PG&E stated in a data request that "PG&E's design practices do not account for falling objects."[53] A falling object can result in hundreds or even thousands of pounds of force to a power line. This can result in no damage to line breakage. The most hazardous scenario would be a dropped object that stresses the line past its elastic limit but does not break the line. An overstressed line will visually look suitable for service but have permanently

[52] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 10-34
[53] Data Request response FEITA_006-Q01-13 provided by PG&E on September 3, 2020 at 3(c)

decreased structural integrity, which will fail under much less wind loads or other stresses than it was designed for.

Additional hazards and risks that are present during EVM are arborists that are trimming and hanging out over live electrical lines. Any slip of fall can result in death by electrocution. PG&E does not train contractors and vendors to their same level of safety standards, human performance tools and test to their operator qualifications.[54]

EVM also results in the removal of millions of pounds of healthy vegetation. This vegetation helps to remove atmospheric carbon and reverse the effects of global climate change. PG&E has cited global climate change as influencing and heightening wildfire risk. EVM is exacerbating climate change, the very cause PG&E is trying to mitigate against.

PG&E has performed a process hazard analysis on EVM to identify hazards, how they occur, what safeguards are currently in place and what recommendations to improve safety are needed. When asked to share what risks they have identified and how they are mitigating the risks PG&E stated "PG&E objects to this question as out of scope of this proceeding. PG&E did not rely on nor include this report in its 2020 RAMP analysis."[55] This is relevant because vegetation management introduces risk and these risks cannot be ignored. PG&E knows that EVM has risk but do not want to share that one of their most effective mitigations can result in future failures and fatalities. Making EVM safer would increase the cost of EVM

[54] PG&E verbal response provided when asked during a meeting
[55] Data Request response FEITA_003-Q01-6 provided by PG&E on August 19, 2020 at answer 1

which would reduce its RSE score, something PG&E probably does not want to acknowledge.

To improve EVM PG&E should only perform EVM activities on de-energized lines, have spotters monitor any falling objects, if a falling object hits the line perform an integrity analysis to ensure there is no latent system risks, plant new trees of the same mass that are cut down (in an area without any power lines) to ensure that EVM does not result in increased atmospheric carbon and train contractors on the same standards and procedures as PG&E employees.

V. ENVIRONMENTAL IMPACTS ARE NOT BEING ADEQUATELY ACCOUNTED FOR

"Safety is the foremost issue in this Application. PG&E's RAMP focuses on safety and effective risk mitigation to further reduce risk to PG&E employees, contractors, and the public".[56] This sentence excludes environmental risk. Later in the report PG&E states: "Environmental attributes are accounted for financially (i.e., within the financial Attribute) because there are no commonly accepted measures of non-monetary environmental consequences".[57] FEITA disagrees with this statement. Not only is this a poor policy toward environmental stewardship, it is incorrect. In previous proceedings as early as 2015[58], PG&E described their RET, which contained seven discrete levels of commonly accepted measures of non-monetary environmental consequences. PG&E is contradicting their previously shared information in this RAMP report.

[56] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 10

[57] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 1-11

[58] A1505003 In the Matter of the Application of Pacific Gas and Electric Company (U39E) for Review of its Safety Models and Approaches. Prepared Testimony Chapter 2 Attachment B at 2-AtchB-2 and Chapter 3 Attachment A at 3-AtchA-2

Dealing with environmental concerns financially implies that as long as the fine is not too large then it is easier to pay the fines then to do what is right by the environment. PG&E's lack of concern with environmental stewardship is alarming. California has more biodiversity and endemic species than any other state[59], this policy of disregarding the environment is inexcusable. PG&E has a major impact on the environment, its infrastructure spans more than 70,000 square miles and is one of the largest landholders in California. They need to have a robust understanding of environmental risks.

PG&E's lack of understanding is exemplified when they stated: "Until the October 2017 North Bay Fires, wildfire risk in California was largely thought to be primarily a Southern California risk".[60] PG&E failed to recognize that many trees and species in California, most notably *Sequoiadendron giganteum* (Giant Sequoia) and *Sequoia sempervirens* (Costal Redwood) have evolved and adapted to need and depend wildfires to survive.[61] These species can live for thousands of years, clearly showing wildfires in California have been common place prior to modern civilization and prior to PG&E existing as a company. There is also an abundance of geological evidence to prove that wildfires are a part of California history and not a new phenomenon. PG&E failed to recognize the risks posed by the environment and risks their own equipment poses to the environment. PG&E needs to better understand the environment and the risks they pose to it. Environmental impact should be a risk attribute itself.

PG&E's lack of understanding of its own environmental impact is further demonstrated when they say, "In addition, many RAMP risks have set forth a "climate focused" alternative mitigation plan to identify the potential impacts that future climate factors may have on the risk

[59] Stein BA. 2002. States of the Union: Ranking America's Biodiversity. Arlington, Virginia: NatureServe.

[60] A2002003 Application of Pacific Gas and Electric Company for Wildfire Mitigation and Catastrophic Events Interim Rates (U39E), Page 3

[61] https://www.fire.ca.gov/media/8657/live_w_fire.pdf,

event and potential mitigations to address those impacts"[62] PG&E is completely ignoring their own contribution and impact toward climate change. Influence on climate change should be an identified risk included in the RAMP report. PG&E releases natural gas[63] from leaks in the pipeline, purging the pipeline, performing maintenance and contributes to releases from natural gas extraction. PG&E also burns natural gas in power plants and cars which converts it to carbon dioxide. PG&E drives hundreds of millions of miles, burning gasoline and diesel every year. The extraction of raw materials PG&E uses (steel, aluminum, plastic, et cetera) also contributes to global climate change. The global impact of climate change contribution of all activities PG&E does should not be ignored, it should be included as a separate and identified risk in the RAMP report.

PG&E chose to account for safety of persons as well as reliability separately. Environmental concerns should not be left out as a separate attribute. A separate attribute will allow PG&E to better understand its environmental impact and how that impact can have far reaching effects. Climate change should be an identified and separate risk to be addressed in the RAMP report.

A. PG&E IGNORES IMPACTS PROTECTED SPECIES

FEITA asked PG&E what financial impact figures PG&E uses to model the impact to various protected species including Golden Eagles, California Condors, protected plant species as well as how they model irreversible harm to the environment, short term reversible environmental impact, damage to a known habitat of a protected species as well as release of toxic and hazardous materials into an aquifer. This question was asked to verify if PG&E's financial model for

[62] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 1-10

[63] The majority of natural gas is methane which, pound for pound has a 25x the impact of carbon dioxide over a 100-year period. See Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. [S. Solomon, D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.)]. Cambridge University Press. Cambridge, United Kingdom 996 pp.

environmental impacts is satisfactory. PG&E's answer was "PG&E did not specifically include the above-referenced environmental impacts in its financial modeling of the RAMP risks."[64] This directly contradicts their stance on including environmental impacts with financial modeling.

PG&E's cavalier attitude toward environmental impacts is unacceptable. Species and habitats that evolved prior to the arrival of PG&E should not be subject to threat of damage or even extinction from PG&E's activities. PG&E says they include environmental costs in financial impact but upon a close look do not actually model environmental impact at all. Their inclusion of environmental impacts in the financial modeling is a farce.

B. PG&E DOES NOT TRAIN PERSONNEL OR CONTRACTORS TO IDENTIFY PROTECTED SPECIES AND HABITATS

FEITA asked PG&E to describe how employees and contractors are trained to identify endangered and protected species of plants and animals in PG&E's service territory. Their response of "PG&E objects to this question as out of scope of the proceeding."[65], is less than satisfactory.

This is another clear example of how PG&E is ignoring environmental risk and masking the risk by including it with financial impacts. If personnel are not trained to even recognize protected species, they will not have the ability to identify when performing work. If they lack the ability then species will be impacted and their impact will not be reported at all.

[64] Data Request FEITA 001-Q01-11, Answer 6 provided on August 21, 2020.
[65] Data Request FEITA 001-Q01-11, Answer 7 provided on August 21, 2020.

PG&E cannot accurately ascertain the financial impact of environmental damage if people do not even have the ability to report on if their activities impact protected species. PG&E is woefully underestimating the financial impact of environmental damage and knowingly hindering their ability to report on it. All persons doing work on PG&E's behalf should be trained on how to identify protected species.

C. GLOBAL CLIMATE CHANGE CONTRIBUTION SHOULD NOT BE IGNORED

Global climate change affects every person and habitat on earth. Climate change is the most important security issue of the 21st century. Climate change is not just a change in temperature, it is a change in precipitation, flooding, storm patterns, air quality and water quality. PG&E should not use climate change as a driver for wildfires[66] and ignore their own massive contributions to climate change. By doing this they are ignoring their own contributions to exacerbating wildfire risk. Global climate change can influence GRC spending and mitigation programs. PG&E contributes influences global climate change and financially benefits from climate change, their own contributions must not be ignored.

The negative consequences of high energy use by modern societies range from the obvious physical manifestation to gradual changes those undesirable outcomes become apparent only after many generations…it has caused harmful levels of air and water pollution.[67] If PG&E does not monitor and assess the environmental risk caused by their operations and maintenance now, by the time the need is there, it's clear that the research should have already been done. Since environmental risks can manifest themselves after many years (including health effects such as cancer),

[66] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 10-1
[67] Smil, V. 2017. Energy and Civilization A History. Cambridge, MA: The MIT Press.

there should be metrics in place to both establish a baseline for future comparison and to monitor the current effects while including environmental risks in the RAMP analysis.

PG&E poses a significant environmental risk (which has not been adequately captured in the MAVF and risk ranking), some of the high-level risks include:

- Combustion of liquid hydrocarbon (gasoline and diesel) from over 141 million miles driven each year[68]
- Wildfires release enormous amounts of carbon dioxide[69] and other toxic chemicals. Smoke is more toxic now than ever as homes are filled with more synthetic, chemical-coated materials that release toxins when burned[70]
- Millions of gallons of hydrocarbons combusted without any catalytic converter in construction equipment
- Release of natural gas into the environment through routine maintenance, operations (including natural gas in valve actuators) and gas pipeline and reservoir leaks and ruptures[71]

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[68] 141 million miles driven per year is provided on page 18-1 of the RAMP Application. This number does not include contractor miles, which should be included as they are driven on behalf of PG&E nor does this number include miles driven in personal vehicles for company business or rental cars. This number also does not include aviation fuel that is burned in PG&E's corporate jet and other aircraft.

[69] The 2018 wildfire season in California was estimated to have released emissions equivalent to roughly 68 million tons (136,000,000,000 pounds) if carbon dioxide. This number equates to about 15 percent of all California emissions. See https://www.doi.gov/pressreleases/new-analysis-shows-2018-california-wildfires-emitted-much-carbon-dioxide-entire-years

[70] Kerber, S. 2011, Fire Technology, Analysis of Changing Residential Fire Dynamics and Its Implications on Firefighter Operational Timeframes

[71] The majority of natural gas is methane which, pound for pound has a 25x the impact of carbon dioxide over a 100-year period. See Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. [S. Solomon, D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.). Cambridge University Press. Cambridge, United Kingdom 996 pp.

- Aviation gasoline (avgas), which contains toxic tetraethyl lead (TEL)[72] combusted in piston powered aircraft used to patrol assets
- The production of finished products (valves, pipe, steel, aluminum, et cetera) contains significant environmental risk from atmospheric pollution to deforestation and habitat loss
- Transportation of materials by sea which combusts high sulfur content fuel oil without any emissions control[73]
- Enhanced Vegetation Management cutting and removing millions of pounds of healthy plants and trees
- Combustion of natural gas to produce power in generating stations as well as to power gas compressors

There are many more examples of the environmental impact and risk from PG&E, the above list was provided to highlight the importance of quantifying and tracking environmental risk. The above examples directly impact global climate change whose impacts range from temperature changes, sea level rise and adverse weather conditions. Global climate change poses a safety risk to the entire world. Tracking current risks will also allow PG&E to establish a baseline to quantify improvements. Without a baseline, it would be difficult to track how much PG&E has reduced risks and emissions over time. PG&E should produce an annual report

[72] The ban of TEL in automobile gas was phased in over a number of years and was largely completed by 1986 and resulted in significant reductions of lead emissions to the environment. TEL has not yet been banned for use in avgas. Avgas contains 0.56 g/L of lead content. Lead can affect human health in several ways, including effects on the nervous system, red blood cells and cardiovascular and immune systems. Infants and young children are especially sensitive to even low levels of lead, which may contribute to behavioral and learning problems and lower IQ in Children have increased sensitivity due to their developing nervous systems.

[73] Ships produce many other environmental impacts other than atmospheric pollution such as discharge of ballast water, noise pollution, discharge of sewage, discharge of trash and cause collisions with whales and other marine life.

that details their own contributions from global climate change of all sources, both direct and indirect.[74]

D. PG&E ALREADY KILLS THOUSANDS OF ANIMALS PER YEAR

The impacts to these species are ignored and PG&E does not include them in their risk modeling. PG&E does not oppose the killing of millions of protected, threatened and endangered birds and bats by wind turbine blades and power lines.

PG&E's power lines kill many animals each year, which are not being accounted for in this RAMP at all. PG&E might consider this normal and not a risk.

The most significant and environmentally damaging birds getting killed are birds of prey, which collide with the blades. Destroying the apex predators of an ecosystem negatively impact everything in the food chain. In addition, bats can succumb to pressure variations on the backside of blades, which rupture ear drums or cause fatal trauma, known as barotrauma.[75] Not only do birds get killed, the suffering is compounded by habitat loss for both living and hunting. Supporting this killing industry is a violation of the Migratory Bird Treaty Act of 1918, which

[74] Indirect sources shall include emissions from contractor and suppliers. How suppliers produce materials should be investigated, whether they use coal power or renewable power, how they ship and pack materials, et cetera When analyzing suppliers PG&E should assess the safety and environmental impact of source materials too. For example, recycled steel that is melted with electric arc furnaces supplied by renewable energy has a negligible environmental impact compared to virgin iron ore mined and smelted with coal that was produced from clear cutting a forest. Also, if suppliers are sourcing raw materials from countries that have human rights violations or do not have environmental laws should also be examined.

[75] Barotrauma is a significant cause of bat fatalities at wind turbines, Erin F. Baerwald, Genevieve H. D'Amours, Brandon J. Klug, Robert M.R. Barclay, Current Biology, Volume 18, Issue 16, 26 August 2008, Pages R695-R696

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makes it illegal to kill any bird protected by the act, even if accidental.[76] PG&E has omitted any discussion in their risk analysis over the killing of birds and bats. This risk shows why including environmental risks as part of a financial model is absurdly wrong.

The ecological impact of predatory birds is profound. They regulate the population of prey species such as mice and rats in addition to help control invasive species. Bats, most of which are insectivores, consume tremendous amounts of insects every time they feed, which on average is 6,000 to 8,000 insects per night. Insects as well as mammal pests, if uncontrolled then impact the farming industries which then impacts the prices that we pay in the stores and the economic stress of people.

Insects are also vectors of viruses that can become epidemics to human or other mammalian populations. Many of the birds have never fully recovered from the use of DDT, such as golden eagles, bald eagles, pelicans, and the majestic and critically endangered California Condor. Wind turbines will not allow for these ecologically important species to thrive or even recover.

Hawaii is the only state that allows mortality data be collected by independent third-party experts and makes the information available to the public. California should do the same. PG&E does not perform an environmental impact report on the power it produces or purchases.

[76] 16 U.S.C. 703-712; Ch. 128; July 3, 1918; 40 Stat. 755 as amended by: Chapter 634; June 20, 1936; 49 Stat. 1556; P.L. 86-732; September 8, 1960; 74 Stat. 866; P.L. 90-578; October 17, 1968; 82 Stat. 1118; P.L. 91-135; December 5, 1969; 83 Stat. 282; P.L. 93-300; June 1, 1974; 88 Stat. 190; P.L. 95-616; November 8, 1978; 92 Stat. 3111; P.L. 99-645; November 10, 1986; 100 Stat. 3590 and P.L. 105-312; October 30, 1998; 112 Stat. 2956

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According to PG&E's 2019 annual report to shareholders there were 3,412 GWh of energy delivered that was derived from wind energy. In California 7.85 birds/turbine/year are estimated to be killed.[77] Bats are slaughtered at a much higher rate that birds. Only a detailed study of all the CA wind farms would give a realistic number. One study found that: every year, an estimated 75 to 110 Golden Eagles are killed by the wind turbines in the Altamont Pass Wind Resource Area (APWRA). Some lose their wings, others are decapitated, and still others are cut in half.[78]

If PG&E continues to use wind power in its portfolio it should only do so after assessing the economic and environmental impact and risk of the killing of birds and bats that comes with wind generated power.

Some ideas to reduce environmental risk include:

- Ensure wind turbines are located away from high bird collision risk areas
- Suppliers employ effective (tested) mitigation to minimize bird fatalities
- PG&E conducts independent, transparent, post-construction monitoring of bird and bat deaths to help inform mitigation
- PG&E calculates and provides fair compensation for the loss of ecologically important, federally protected birds
- Support wind farms that employ bright UV lights to deter bats and birds from the farms
- Only buy power from vertical axis turbine blades

[77] https://www.fws.gov/birds/bird-enthusiasts/threats-to-birds/collisions/wind-turbines.php
[78] https://goldengateaudubon.org/conservation/birds-at-risk/avian-mortality-at-altamont-pass/

- Support wind farms that employ cameras and GPS to detect incoming flocks and turn off the turbines in time for the birds to fly through

E. ENVIRONMENTAL DAMAGE FROM WILDFIRES IS BEING IGNORED

Wildfires damage huge areas of land and vital habitat to animal species. Wildfires can burn and destroy protected plant species. PG&E ignores damages to protected plant species. Wildfires can also result in devastating habitat loss to protected animals. Habitat loss from wildfires caused by PG&E can endanger iconic species such as the California Condor. During the devastating fires of 2020 one fire destroyed a condor sanctuary which resulted in twelve (12) condors missing.[79] Some of the missing birds abandoned chicks who were too young to fly, their fate is unknown, possible being burned alive. According to the U.S Fish and Wildlife Service, there are only 160 condors flying free in California. Twelve missing represents 7.5% of the free California population, clearly a very significant impact.

PG&E's risk model should not ignore the environmental damage they cause and the impact to protected species.

F. CHRONIC AND LONG-TERM HEALTH CONSEQUENCES ARE BEING IGNORED BY PG&E

PG&E has a long history of environmental damage and endangering persons by exposing them to hazardous chemicals and conditions. The hexavalent chromium ground water contamination disaster at Hinkley and Topock is well understood and

[79] https://www.sfchronicle.com/california-wildfires/article/Fires-destroy-Big-Sur-condor-sanctuary-15516997.php

prime examples of how PG&E's operations can result in disastrous health effects to the public. The groundwater contamination started in 1952 and the cleanup effort is still ongoing to this day. This example shows that long-term health impacts can take many years to manifest. Instead of waiting for long-term health impacts to appear, PG&E should be proactive in identifying and mitigating them as soon as possible.

Wildfires pose significant long-term health effects. When wildfires burn millions of tons of particulate matter are released to the atmosphere, which people then breathe in. When wildfires burn houses, houses contain a large amount of plastics and other material that releases toxic fumes and gases that are again released to the atmosphere and large populations breathe the toxic fumes in. The EPA has published that:

> *The effects of smoke from wildfires can range from eye and respiratory tract irritation to more serious disorders, including reduced lung function, bronchitis, exacerbation of asthma and heart failure, and premature death. Children, pregnant women, and the elderly are especially vulnerable to smoke exposure. Emissions from wildfires are known to cause increased visits to hospitals and clinics by those exposed to smoke.*[80]

PG&E should be assessing the public health effects from wildfires and how their failures of equipment result in long term health effects to the population.

Some other potential long-term impacts that should be monitored and assessed include but are not limited to:

[80] https://www.epa.gov/air-research/wildland-fire-research-health-effects-research#:~:text=The%20effects%20of%20smoke%20from,especially%20vulnerable%20to%20smoke%20exposure.

- Exposures to chemicals used during operating and maintenance
- Exposure to existing carcinogens and toxic materials used by historical operations that are still present in the pipelines and ground soil[81]
- Environmental impact of operations (vegetation management, emissions, et cetera)
- Chronic respiratory exposure to diesel and combustion exhaust fumes
- Chronic exposure to noise when living next to PG&E equipment
- Chronic respiratory exposure to particulates and metal fumes from cutting, grinding and welding
- Chronic respiratory exposure to dust and particulate matter from excavations

All long-term health effects from all PG&E operations should be assessed to understand the risks PG&E populations pose to the public, employees, contractors and the environment. These long-term health effects may take decades to manifest themselves, but when they do, they will have very large consequences, equal to or greater than many of the risks presented in RAMP.

G. PG&E BENEFITS FROM GLOBAL CLIMATE CHANGE

It is possible that PG&E is ignoring their contributions to global climate change and environmental impacts because they profit tremendously from it. PG&E has to update their system with projects that earn a rate of return to mitigate climate

[81] Historically gas measurement devices used mercury, asbestos was commonly used, polychlorinated biphenyls (PCBs) were commonly used and pipeline liquids contain a mix of hazardous substances. Many PG&E facilities contain contaminated soil from historical exposure and poor environmental practices.

change and adverse weather conditions. If sea levels rise, they would have to spend a lot of ratepayer money to relocate assets and harden them. PG&E is poised to make a lot of money for their shareholders in the coming decades on climate change related projects, this could be a reason why they do not want to disclose their contributions and have failed to quantify the risks of climate change and environmental impact.

VI. INDIRECT SAFETY CONSEQUENCES MUST NOT BE IGNORED

FEITA strongly disagrees with PG&E when they state that only direct safety consequences should be considered: "This risk analysis considers only direct safety consequences in computing Risk Scores. The Utility Reform Network (TURN) suggested that indirect safety consequences must be included to obtain accurate Risk Scores. We disagree."[82] TURN is correct in that indirect safety consequences must be included, FEITA would like to add that financial consequences should also must be included.

PG&E has failed to even define what is a direct and an indirect consequence. First and foremost, PG&E should provide a clear definition of a direct consequence and an indirect (secondary) consequence in their RAMP report and be consistent throughout all identified risks. In the absence of PG&E's definition, FEITA will assume that:

- Direct consequence is one that an action has an immediate effect in the same area at the same time
- Indirect consequence are impacts later in time and further removed, but reasonably foreseeable.

[82] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 1-13

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PG&E is inconsistent in their RAMP report, sometimes they only include direct consequences but they have also included indirect consequences where it agrees with their agenda and spending.

By this definition the direct impact of a wire down is damage to the circuit, release of electrical energy to the ground and if persons are in the area electrocution. The indirect impact is ignition, wildfire, loss of customers, financial liabilities, et cetera.

The same definitions can be applied to gas loss of containment events. During a gas pipeline rupture (or leak) the direct consequence is a gas release to the atmosphere. The indirect consequences are fire, explosion, safety impacts to persons and financial damage to property. Another indirect consequence would be contribution to global climate change.

Another example of an indirect safety consequence is the migration of natural gas. A loss of containment event can result in gas migrating into homes of other structures. Inside a home the gas could find an ignition source resulting in an explosion. The explosion would be the indirect consequence of a gas release. Notably this occurred in 2014 while PG&E crews were onsite performing work. In 2014 PG&E blew up a house in Carmel because gas migrated into a home and found an ignition source. Another example of a gas release migrating into a structure is the 2014 Harlem Explosion that killed eight people, injured more than 50, displaced more than 100 families and impacted rail operations for over 7.5 hours.[83] Ignoring secondary consequences like the Carmel example is worrisome.

It is illogical to only include direct consequences because that is unrealistic, every incident will have both direct and indirect consequences. FEITA recommends that PG&E consider foreseeable and reasonable consequences, regardless of if they are indirect or direct.

[83] National Transportation Safety Board Report PAR-15-01

Indirect safety and financial considerations must be analyzed in the identified risks to provide a holistic view of the societal impact and consequences. Indirect consequences for electrical power loss should include:

- Power loss to schools and hospitals
- Power loss to persons who use a ventilator (or other life sustaining medical equipment)
- Power loss to research facilities who lose refrigeration
- Spoilage of food
- Loss of employee productivity
- Impact to the internet and cellular communication including the loss of the ability to communicate critical information to the public during an emergency
- Impact to manufacturing
- Impacts to drinking water and waste water treatment facilities
- Loss of heating and cooling to homes
- Impacts to financial institutions and the ability to make payments
- Impact to transportation (airports, air traffic control, traffic lights, et cetera) and associated safety impact
- Impact to fuel and refining capabilities
- Impact to food sources and producers
- Impacts to the Gas system (Electric driven compressors, electric power supply for control systems, electric power for communication and instrumentation, et cetera)
- Many more indirect impacts have been discussed above and will be discussed throughout this document.

Indirect consequences for loss of gas supply should include:

- Impact of loss of power generation in natural gas fired power plants which supply 40% of California's power[84]
- Impact of heating to homes and businesses
- Impacts to cooking fuel to homes and restaurants
- Impacts to manufacturing and business that use natural gas as a reagent, fuel or heat source (boilers, dryers, heaters, et cetera)
- Impacts to petroleum refineries and fuel supply
- Impacts to reliability of backup electrical generation from natural gas generators
- Many more indirect impacts have been discussed above and will be discussed throughout this document; all of which should not be ignored.

An extended loss of energy would be life changing and a disaster. PG&E's folly of ignoring indirect safety and financial risks is irresponsible and dangerous. FEITA understands that it would be difficult to accurately quantify, but the SMEs at PG&E should be able to reasonably estimate the indirect consequences within an acceptable error margin. PG&E has over 115 years of operating experience[85], surely, they should have some knowledge of indirect consequences by now.

Including indirect causes would only advance the rigor of the risk analysis and align with PG&E's own goal, "Our goal is to be a leading utility in adopting and advancing rigorous risk management practices".[86]

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[84] U.S. EIA, Electric Power Monthly (February 2019), Tables 1.3.B, 1.7.B, 1.9.B, 1.10.B, 1.11.B, 1.17.B

[85] PG&E's Articles of Incorporation were filed 10/10/1905 with the state of California. See a copy here: https://businesssearch.sos.ca.gov/Document/RetrievePDF?Id=00044131-2710465

[86] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 1-3

VII. CONCERNS ABOUT COMPETENCY OF PG&E PERSONNEL

The competency of PG&E employees, and contractors, is paramount in regards to safety. If employees are not competent, they may make erroneous assumptions which leads to unrealized risks or overexaggerates risks. Furthermore, persons of low ability reach erroneous conclusions and their incompetence robs them of the metacognitive ability to realize it.[87] PG&E has omitted many risks, failed to recognized the risks in their mitigation plans, ignored secondary consequences and ignored inherently safer mitigations. FEITA is concerned that PG&E leadership has put employees who are not qualified, and do not have the ability to even recognize their own incompetence, in positions to develop the risk analysis and mitigation strategy. This has resulted in a flawed approach that puts every ratepayer and the environment in jeopardy. The RAMP team has objected to the relevance of many pertinent data requests, which further shows their incompetence. The training, knowledge, competency and qualifications of personnel identifying, managing and controlling risk is a large concern.

During the 2019 fire season, the majority PG&E's emergency response team was not trained on.[88] They put incompetent people in charge of shutting off power. PG&E's lack of competent employees in 2019 is not a fluke or a one off. PG&E has relied on incompetent and untrained employees to not only develop this RAMP Application but to design and operate their systems as well.

A. CONCERNS OVER VICE PRESIDENT COMMITTEE COMPETENCY

[87] Dunning, D and Kruger J, January 2000, Unskilled and Unaware of It: How Difficulties in Recognizing One's Own Incompetence Lead to Inflated Self-Assessments, Journal of Personality and Social Psychology 77(6):1121-34

[88] https://sanfrancisco.cbslocal.com/2020/10/18/wildfire-pge-2019-shutoff-mismanaged-no-disaster-training/

PG&E relies on a vice president committee to approve risks in the corporate risk register[89], which is the basis of the risks identified in the RAMP report.

> **The very basis of the risks, controls and mitigations is inherently flawed with the judgement of persons who lack qualifications, technical ability, training and experience.**

If a credible risk is not approved, it will not be analyzed in RAMP. FEITA requested information about the training, knowledge and competency of the vice president committee.[90] PG&E responded that:

> "PG&E does not have specific minimum requirement qualifications for Committee members in the areas of safety qualifications, experience and training."[91]

The committee is comprised of sixteen (16) employees, who have an average time in their respective position of 3.4 years, with the newest member only in their position for two months, the median time in position is 1.3 years.[92] It is commonly accepted that most people take around 10,000 hours to master a subject. It would be improbable to assume that the committee members are devoting more than a few hours a day to improve their safety and risk skills, which would result in over a decade to achieve mastery in safety and risk for a single subject. This RAMP presents twelve different risks, so it would take almost an entire career to gain the

[89] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 4

[90] FEITA Data Request 01, Sent on July 16, 2020. Response received on August 21, 2020

[91] PG&E Data Request Response, RAMP-2020_DR_FETA_001-Q01-11, received August 21, 2020

[92] PG&E Data Request Response, RAMP-2020_DR_FETA_001-Q01-11, received August 21, 2020. The duration of time is provided at the time the data request was answered.

knowledge to be an authority on all identified risks. The committee approving the risks are simply unqualified.

In the data request response, PG&E provided the names and titles of each committee member. The vast majority of the committee members do not have a technical degree or one that is related to the risks or the controls and mitigations identified in the RAMP report.[93] It is very difficult to believe that employees who specialize in corporate communications, audit & privacy, human resources, counsel, ethics and compliance, procurement, reporting, regulatory and external affairs are experts in the technical and engineering risks identified in the RAMP report. Not only are they unqualified in the technical aspects of the risk they are also not even qualified to comment on the technical aspects of the MAVF.

1. RAMP REPORT COMPLETED UNDER AN UNQUALIFIED CHIEF RISK OFFICER

The highest risk is wildfire but the VP in charge of the community wildfire program has a degree in general science[94], not forestry, fire science, meteorology, wildland fire/fuels management, wildfire management or similar. The Chief Risk Officer is the equivalent of a certified public accountant with a degree in business and finance[95], hardly a qualification to comment on engineering and operational risks. Even if PG&E replaced the

[93] Employees provided their educational history and experience on LinkedIn

[94] http://www.pgecorp.com/corp/about-us/officers/company/deborah-powell.page

[95] PG&E may have changed personnel or roles after the data request was responded to or after filing of the 2020 RAMP. PG&E has not provided an updated response, the information presented here is as current as PG&E has provided. See qualifications of Chief Risk Officer here: https://www.pgecorp.com/corp/about-us/officers/corporation/stephen-cairns.page Accessed on July 10. Accessed on July 10, 2020

CRO with a qualified employee, the RAMP analysis is already completed and PG&E would not have time to re-analyze the wildfire risks and mitigation programs prior to submitting its GRC. All risks, controls and mitigations in this RAMP Application were finalized under the tutelage of an unqualified CRO.

2. PG&E DOES NOT TRAIN OR QUALIFY THEIR VP COMMITTEE

PG&E does not provide or require training to this VP committee, nor do they require minimum qualifications or experience. Their role is most likely more administrative then technical. They are also probably very far away from the actual day to day work. It is very difficult to believe that all the employees on the committee are qualified to comment on risks, mitigations or controls.

PG&E leadership has knowingly empowered employees who are not qualified to approve risks, the very ones that mitigation plans are developed for, the same ones that PG&E will request billions of dollars for in the GRC. PG&E is poised to profit enormous sums of money based on the identified risks from unqualified employees.

3. THIRD PARTY VERIFICATION OF THE VP COMMITTEE IS REQUIRED

It is recommended that an independent party to PG&E such as the Federal Monitor, CPUC or other outside firm review the competency, training, experience and qualifications of each individual on the VP committee to ensure that they are competent to approve the corporate risk register. All gaps and findings should be made available and swiftly addressed.

B. LEADERSHIP IS RESPONSIBLE FOR LACK OF COMPETENCE

The employees and analysts performing the work within PG&E are not at fault for a lack of knowledge and competence within PG&E. They are working in a sluggish bureaucracy in which all decisions must be routed through leadership. The same leadership that is unskilled and unaware of their own inabilities. The same leaders who manifest the culture at PG&E. Competency deficiencies start at the top.

C. SUBJECT MATTER EXPERTISE IS SUBJECTIVE

PG&E has not specified what qualifications, training, certifications or even publications constitutes a subject matter expert (SME). It would be wrong to assume that years of experience equates to expertise or confuse activity with achievement. Since the risk framework relies on subject matter expertise of unknown validity, it is hard to trust the identification of risk and assumptions are correct.

PG&E should specify what constitutes a SME and validate that SMEs that provide input into RAMP are actually SME and not just employees who have been with the company a long time. Years of experience at PG&E should not be a qualification, discussed below highlights how someone can be with the company their entire career and still be unqualified.

D. CONCERNS REGARDING COMPETENCY OF THE ENTERPRISE AND OPERATIONAL RISK MANAGEMENT DEPARTMENT

PG&E's Enterprise and Operational Risk Management (EORM) department "has centrally governed the Company's processes for identifying, assessing, mitigating and monitoring risk since its inception in 2012"[96] EORM works with local execution to identify, evaluate, monitor and mitigate risks.[97] The competency of the Chief Risk Officer, EORM leadership and subject matter expertise is in question. PG&E has not been able to prove competency.

PG&E describes the organizational structure in Chapter 2 of the RAMP report, going into detail about the reporting hierarchy and responsibilities of top management. This description describes different departments but notably leaves out the qualifications of the Chief Risk Officer (CRO) and other key individuals.

PG&E is relying on the opinion, competency and knowledge of a CRO to run a department, if the CRO has a lack of safety experience, is not a recognized expert and does not hire competent people then the entire program will not be useful.

The safety performance of PG&E in the previous decade has been poor and unbecoming of a public utility. Some key safety incidents include starting over 1,500 fires[98], pleading guilty to 84 counts of manslaughter, seven (7) gas transmission line ruptures[99] including the tragic San Bruno Explosion, thousands of gas overpressure events, gas distribution leaks and ruptures, Carmel gas explosion in 2014, San Francisco gas explosion in 2019, and multiple fatalities to

[96] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 2-1

[97] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 2-2

[98] https://www.businessinsider.com/pge-caused-california-wildfires-safety-measures-2019-10, https://www.cpuc.ca.gov/PGEFireIncidentReports/

[99] Data Request response FEITA_002-Q01-19 provided by PG&E on August 13, 2020, Question 01

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the public, employees and contractors. Many of these incidents occurred under the guidance of the EORM department.

PG&E discusses their risk quantification department and touts the fact that they have increased their personnel, with a doctorate degree, from one to four.[100]. Upon further review of the four doctoral employees[101], they do not seem to be qualified in safety or reliability risks, their doctoral thesis/dissertations are unrelated to the safety and risks presented in RAMP. Their dissertation and doctorate degrees are:

- *Research Managing Volumetric Risk in Energy Procurement* (2006)[102], Ph. D. in Industrial Engineering and Operations
- *Evaluating Biomass Energy Policy in the Face of Emissions Reductions Uncertainties and Feedstock Supply Risk* (2012)[103], Ph. D. in Departments of Engineering & Public Policy and Civil & Environmental Engineering
- *Exchange rates and the economy* (2010)[104], Ph. D. in Economics
- *Computationally Efficient Hydropower Operations Optimization For Large Cascaded Hydropower Systems Reflecting Market Power, Fish Constraints, Multi-Turbine Powerhouses, and Renewable Resource Integration* (2017)[105], Ph. D. in Environmental and Water Resources Systems Engineering

None of the employees with doctoral degrees working in the EORM department have a degree related to safety, reliability, dispersion analysis, failure analysis, equipment design, meteorology, wildfires, material science, controls engineering,

[100] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 2-4
[101] See WP 2-1 for a list of qualifications
[102] See WP 2-1
[103] https://www.cmu.edu/cee/research/recent-theses.html
[104] https://search.library.ucdavis.edu/
[105] https://ecommons.cornell.edu/handle/1813/56992

gas engineering, electrical distribution or power generation. A review of the content of their dissertations did not find any relevant experience to the twelve risks identified in the RAMP report. This is reflective of the leadership at PG&E to not put in place and empower employees who are suited for their role.

The work experience and expertise of the EORM department employees and CRO is a concern that they are not qualified for their positions and that they are in a position to "Identify and evaluate risks, establish metrics to monitor risks, provide oversight, provides strategy, analysis, and support for LOBs".[106] With unqualified personnel they will not be able to recognize their own shortcomings in identifying and evaluating risk, which places the public at risk.

1. FAILURE TO FACT CHECK AND INCONSISTENCIES

EORM, for being responsible for the RAMP Application should have prof-read the entire report and ensured consistency and accuracy. Throughout the report there are conflicting terminology, errors, inconsistencies and wrong definitions. The below list is not comprehensive but provides examples highlighting the lack of competence in proof-reading.

- Overpressure has been used as 'overpressure' in the chapter titles and the majority of the RAMP report but also as 'over pressure' on some occasions and in the glossary.[107]

[106] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 2-2 and Page 2-3

[107] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page AppA-5 and Page 8-4

- Maximum Allowable Operating Pressure has been incorrectly defined in Chapter 7.[108] The definition provided contradicts the federal and state code.
- Strength test and pressure test have been used interchangeable instead of using consistent terminology
- Throughout the report loss of containment is shown as LOC and LoC. This acronym should be consistent throughout the document.
- SCADA stands for Supervisory Control and Data Acquisition. PG&E incorrectly called it System Control and Data Acquisition.[109] SCADA is used on both Gas and Electric and many other industries. An error like this is glaring.

E. CONCERN REGARDING PG&E EMPLOYEE COMPETENCY

PG&E has a large workforce with many lines of business. A large population of PG&E employees regularly and frequently transfers internally (i.e. from one line of business to another, or from one department to another).[110]

In a data request, FEITA asked PG&E if employees are trained for their position when they take on a new role.[111] This question was posed to see if PG&E has identified what training is required for each job title. For example, if an employee transfers from gas to electric do, they receive any training on the electric system, hazards, risks and job specific training, et cetera Each position should have

[108] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 7-8

[109] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page AppA-6

[110] Based on countless discussions with employees as well as reviewing PG&E employee Linkedin.com information

[111] Data Request response FEITA_002-Q01-19 sent to PG&E on July 16, 2020, Question 09

minimum training requirements identified with employees required to be trained for their role. This is especially important for leadership.

PG&E responded with:

> "PG&E objects to this question on grounds of relevance and burden. How gas employees are trained for their job is not relevant to the risk analysis in PG&E's RAMP report. Furthermore, seeking this information for all gas employees is overly broad and potentially unduly burdensome."[112]

How employees are trained for their job is very relevant to the risk analysis provided in the RAMP report. If employees are not trained for their jobs, how can they even do their job let alone comment on risk. This response highlights the incompetence of PG&E employees discussed above. If one cannot recognize how training for their job is important, they need training to do their job.

This should have been a very easy question for PG&E's training academy to answer. PG&E should have responded that the training academy maintains records of training, has identified training for each role and when employees move positions, they receive training.

This response is extremely concerning in that PG&E does not see how employee training relates to risk and how that training influences Safety Culture (RAMP Chapter 5), employee safety (RAMP Chapter 16) and how human error can cause an incident (discussed in many sections of the RAMP report). Training and qualification are directly related to safety. If training and qualifications are not

[112] Data Request response FEITA_002-Q01-19 provided by PG&E on August 13, 2020, Question 09

relevant to safety at PG&E then ratepayers should never have to pay for training of PG&E employees or contractors.

Conversations with employees, not on the RAMP team, revealed that PG&E previously had a two-week long training for new gas engineers called GAS-0731. Unfortunately, this training is not required for anyone transferring to gas engineering team from anywhere within the company. An engineer can transfer to gas from electric (or vice versa) and start working on projects without having even a minimum amount of training. These are the same engineers who design the equipment, safeguards, controls and mitigations. It is hard to believe that someone who lacks training will produce safe designs.

FEITA was hoping to receive a response that PG&E has a training requirement based on each position within the company and if an employee moves to a new role, they are required to take the appropriate training within 30 days, or similar response. Internal movement within the company, without proper training for the new position, is very alarming in that employees are not mastering their position. Employees can just move around the company every year to mask their own incompetence in their role. They can move to a new position before their leadership can realize they are not fit for service. All of this behavior seems to be acceptable and normal for PG&E.

To compound the lack of training, PG&E does not enforce technical training for many supervisor, manager or leadership roles. If technical employees are untrained and have a supervisor who is an administrator and cannot provide any guidance on technical questions, employees are working blindfolded.

The PG&E training academy should work with all lines of business to identify training requirements by position so that when an employee transfers, they will receive the proper training. Employees who are untrained will not be knowledgeable and will not know what good or bad looks like. They will simply lack the skills to see what good looks like. PG&E is endangering the public if employees are unqualified and incompetent personnel.

F. SUGGESTIONS TO IMPROVE COMPETENCY

PG&E should not rely on long time PG&E employees to run the EORM program and department, they should bring in a recognized safety expert who has experience in multiple industries to usher in change. EORM employees should be experts in all lines of business and be a resource for anyone in the company to seek advice from. The status quo of PG&E is not good enough for safety. PG&E should employee individuals who are recognized internationally in the field of safety or associated with internationally recognized organizations such as the Mary Kay O'Conner Process Safety Center.

PG&E should establish qualification, training and experience requirements by position. PG&E should also enforce these minimums when employees move internally within the company. PG&E should prove competency of employees responsible for safety and risk management.

All safety, risk and threat organizations should not work independently from each other, they should work together. Instead of having multiple fragmented risk groups, they should be under one umbrella of influence. The risk groups should have the authority and competency to swiftly make decisions and implement changes. They should not be handcuffed by PG&E's sluggish bureaucracy to wait on unqualified leaders to decide for them.

FEITA would like to see PG&E establish minimum criteria to qualify a subject matter expert such as author of technical articles, professional engineering licensure, continual education requirements, participation in professional membership associations, advanced degrees, patents, et cetera Individuals who are responsible for safety at PG&E should be highly qualified, respected and have education and experience commensurate with their position requirements.

VIII. PG&E RAMP TEAM OBJECTED TO RELEVANT DATA REQUESTS

Almost all activities within PG&E can be related to safety. Activities as seemingly insignificant as putting on shoes impact safety performance. If one did not put socks on properly, blisters can form and lead to time away from work or distractions when performing safety critical work. If shoes are not sized properly, balance can be impacted resulting in an injury from a fall. If laces are loose shoes can fall off. Any distraction in the workplace such as a blister or loose shoes can result in loss of focus when operating equipment, a slip, trip or fall all of which can lead to operational upsets, incidents or fatalities.

All of the objections by PG&E relate to the competency of the personnel responding to Data Requests. The respondents failed to recognize how the information could be used by the RAMP team to improve the RAMP analysis and reporting. Many key objections have been discussed in context of their respective sections in this document.

[please note that this section is still in progress. All data requests are available to all parties. The next revision of this document will detail objections, why it is important to safety and what FEITA's expected response was]

IX. PG&E FAILED TO COLLABORATE WITH INTERNAL SAFETY, RISK AND THREAT TEAMS IN THE DEVELOPMENT OF THE 2020 RAMP APPLICATION

FEITA asked PG&E to identify all departments/teams/groups within PG&E that contain either safety, threat or risk in their name/title and how they contributed to the RAMP Application and if they didn't contribute why not.[113] Their irresponsible response is provided below:

> *PG&E objects to this data request on the grounds that the request is overbroad and unduly burdensome to the extent that it calls for "all departments/teams/groups that contain either safety, threat or risk in their title" within PG&E. The responses to this request will not lead to a meaningful finding relating to PG&E's risk assessment in RAMP.*[114]

FEITA has very large concern that PG&E has not adequately coordinated and worked with the appropriate risk and safety teams within the company to develop the risks, mitigations and controls in the RAMP report. This response also shows the ignorance and incompetence of PG&E by failing to see how their internal safety and risk organizations could contribute to RAMP.

It is possible that PG&E is purposely trying to mask their lack of collaboration with objecting to this data request. They may be trying to hide that important risk teams did not help develop the RAMP. Or the RAMP and EORM teams are simply unaware of the many risk, safety and threat organizations that exist in the PG&E

[113] Data Request FEITA_008-Q01 sent to PG&E on September 30, 2020, Question 01

[114] Data Request response FEITA_008-Q01 provided by PG&E on October 14, 2020, Question 01

empire and are too ashamed to admit they didn't involve people that could have helped.

PG&E has a large number of safety groups, it is highly probable that many don't even know the others exist and there is a lot of inefficiencies and duplicated work. Many of the concerns about the risks, mitigations and controls may have been eliminated if PG&E coordinated properly with their own organization.

A. PROCESS SAFETY WAS NOT INVOLVED IN RAMP

Process safety could be one of the most important organizations within PG&E. PG&E's lack of reliance on process safety and their lack luster commitment to process safety is very concerning. A robust process safety program would greatly improve the ramp analysis, effectiveness of controls and mitigations. Excluding a group whose primary function is to address safety, safety culture, identify risks, manage risks and learn from experience in this RAMP is revealing. It shows PG&E's lack of commitment to safety and risk reduction.

1. WHAT IS PROCESS SAFETY

Process safety involves making sure facilities are well designed, safely operated and properly maintained. Process safety starts at the early design phase of building facilities and continues throughout their life cycle, making sure they are operated safely, well maintained and inspected regularly to identify and deal with any potential hazards.

On December 3, 1984, a pesticide plant in Bhopal India accidently released around 40 tons of methyl isocyanate into the atmosphere resulting in over

100,000 injured and 2,000 dead.[115] As a result of the Bhopal tragedy and other industrial accidents, the Occupational Safety and Health Administration (OSHA) responded with the publication of Process Safety Management (PSM) for highly hazardous chemicals.[116] Closely related to OSHA's PSM is the environmental protection agency's (EPA) Risk Management Plan (RMP).[117] OSHA has exempted natural gas utility operations from PSM requirements and enforcement. However, some utility facilities and operations still may fall under OSHA or EPA jurisdiction if they store a certain quantity of chemicals onsite.

OSHA has not specifically defined what process safety means. Many companies define process safety very similarly. Process safety is achieved through developing and implementing a framework that is a blend of engineering and management, managing operating systems and operating practices and by applying good design and engineering principles.

In essences process safety is the overall combination of things to avoid destroying a or significantly altering a business.

Other industries have had to comply with OSHA and EPA requirements for almost thirty years now. OSHA PSM contains the following 14 elements:

1. Employee Participation
2. Process Safety Information
3. Process Hazard Analysis

[115] American Institute of Chemical Engineers, Incidents that define Process Safety (New York, Wiley,2000)

[116] 29 CFR § 1910.119

[117] https://www.epa.gov/rmp

4. Operating Procedures
5. Training
6. Contractors
7. Pre-Startup Safety Review
8. Mechanical Integrity
9. Hot Work Permit
10. Management of Change
11. Incident Investigation
12. Emergency Planning and Response
13. Compliance Audits
14. Trade Secrets

It is easy to see how the 14 elements directly relate to RAMP, many of controls and mitigations described in the RAMP report are one of the 14 elements. PG&E has implemented an even more robust process safety system in gas operations that contains twenty (20) elements. Their system is the Center for Chemical Process Safety (CCPS) system.

2. INCIDENTS THAT DEFINE PROCESS SAFETY

There are too many incidents and disasters that define why process safety is needed. Many of the incidents below did not happen in the utility industry but are widely known. The lessons that can be learned are relevant and help widen our vision when faced with challenges and risks. The below incidents are shown to illustrate what is process safety and to show that each and every incident can be analyzed to improve PG&E's risk analysis and operations:

1. Blind Operations – Three Mile Island Nuclear Core Meltdown – March 28, 1979
2. Design – Methyl Isocyanate Release, Bhobal, India, December 3, 1984, NASA Challenger Disaster, January 28, 1986, Hindenburg Disaster, May 6, 1937
3. External Causes – Pemex LPG Terminal, November 19, 1984
4. Inspection and Maintenance – HF Release at Marathon Oil Refinery, September 23, 1976
5. Knowledge and Training – BLEVE at Elf Refinery, January 4, 1966
6. Lack of Hazard Identification – Sinking of the Titanic, April 15, 1912, Esso Longford Gas Plant Explosion, September 25, 1998
7. Management of Change – Chernobyl, April 26, 1986, Dutch State Mines Nypo Plant, Flixborough, June 1, 1974
8. Not Learning from Near Misses – Space Shuttle Colombia, February 1, 2003, Air France Concorde Crash, July 25, 2000
9. Operating Practices – BP Texas City Iso Unit Explosion, March 23, 2005
10. Permit to Work – Piper Alpha Platform, July 6, 1988
11. Emergency Response – Sandoz SA Warehouse Fire, November 1, 1986
12. Human Factors – Exxon Valdez, July 10, 1976

The following list of incidents also define process safety:

- San Bruno Explosion
- Camp Fire

- 2012 Kern Power Plant Demolition
- Carmel Explosion
- Butte Fire
- Trauner Fire
- Hinkley Groundwater Contamination
- Et cetera

B. PROCESS SAFETY AT PG&E

PG&E gas operations implemented a process safety team after San Bruno to improve safety. Their primary roles, responsibilities and goals, as provided by PG&E[118], are

- Provide and instill process safety rigor to ongoing activities, programs, and guidance documents;
- Coach other business partners in assessing process safety needs;
- Assess and support improvement activities for Management of Change;
- Participate in and/or facilitate PHA's and Pre-Startup Safety Reviews;
- Perform likelihood/consequence analysis;
- Deliver PS training across Gas Operations;
- Perform Hazard Identification and Risk Analysis (HIRA) studies;
- Perform Quantitative Risk Analysis (QRA), Gas Plume Dispersion Consequence modeling, and Hazardous Area Classifications (HAC);
- Conduct cause evaluations;

[118] Data Request response FEITA_002-Q01-19 provided by PG&E on August 13, 2020, Question 11

- Improving and increasing awareness of the Gas Operations Management of Change (MOC) process;
- Delivering Process Safety training to Gas Transmission Operations Engineers;
- Conducting peer reviews of project PHAs and Pre-Startup Safety Reviews;
- Embedding Process Safety principles and requirements into standards and procedures for Gas Operations;
- Focusing on gas incident trends to address gaps and prevent future incidents;
- Creating an accessible lessons learned database for incidents and near hits.

Many of the above activities are directly related to RAMP and many mitigations and controls discuss the above activities. Clearly process safety would vastly improve the RAMP analysis and also reduce the need to perform redundant work such as likelihood and consequence analysis. Although important and very relevant, the Gas Operations Process Safety team did not contribute to the 2020 RAMP report nor were involved in identifying and ranking risks.[119]

Further details and complete job description(s)[120] of the process safety department show how process safety is a fundamental role in safety and it is so important that Gas Operations has proclaimed that “Process Safety knowledge and competency must be embedded throughout the Gas Organization”.[121] It is troubling and puzzling why process safety was not involved in RAMP.

[119] Data Request response FEITA_001-Q01-11 provided by PG&E on August 21, 2020, Question 08

[120] https://www.ifpte20.org/wp-content/uploads/2019/11/ESC-PGE-Contract-Appendix-1-monthly-job-descriptions-Oct-2019-update.pdf

[121] Letter of Agreement between ESC and PG&E 18-33-ESC, dated December 13, 2018

Pacific Gas and Electric (PG&E) was the first utility known to be certified with a process safety certification.[122]

Process safety has proven to be effective in saving lives and reducing incidents in other industries and should be a principal contributor to RAMP.

C. PG&E'S COMMITMENT TO PROCESS SAFETY IS LACKING

An understaffed safety team is ineffective and is unable to adequately support the organization. PG&E first started a gas operations process safety department in 2013 and has been growing the department ever since, at one point they had fourteen (14) engineers along with a manager and director.[123] PG&E's Gas Operations Process Safety team is understaffed, PG&E responded that they currently they have only five employees.[124] After responding, according to LinkedIn information one of the five employees left the department, leaving them with four engineers. Four engineers are less than half of the minimum agreed upon staff between PG&E and the Engineers and Scientist of California (ESC) Union. PG&E and ESC agreed to have a minimum of nine (9) engineers.[125] This is a reflection of the safety culture of PG&E. All safety departments should be fully staffed to support their organizations.

[122] http://www.pgecurrents.com/2016/08/18/pge-becomes-first-natural-gas-utility-to-receive-process-safety-certification/

[123] As indicated by LinkedIn.com data

[124] Data Request response FEITA_001-Q01-11 provided by PG&E on August 21, 2020, Question 08

[125] NLRB Case 20-RC-174840, May 31, 2016 Gas Process Safety Engineers

X. LACK OF COLLABORATION WITH RECOGNIZED AUTHORITIES ON RISK AND HAZARD EVALUATIONS

Throughout the RAMP report there is a significant lack of utilizing research expertise. PG&E has had Lawrence Livermore National Laboratory perform a threat (risk) analysis, worked with the UC Berkeley Center for Catastrophic Risk Management and is listed as a project sponsor for The B. John Garrick Institute for the Risk Sciences, Natural hazards Risk and Resiliency Research Center (NHR3) project or Natural Gas Infrastructure Safety and Integrity Seismic Risk Assessment and Enhanced Training[126]. Yet none of these initiatives and past projects have been mentioned in the RAMP report.

The NHR3 project is developing a risk assessment methodology that quantifies the ground motion, fault displacement, landslide and liquefaction risks for California gas infrastructure. PG&E did indicate that "PG&E's support is relatively small" and that "PG&E's Gas infrastructure asset model for seismic risk assessment can benefit from updated hazard modelling and component fragilities research data to better quantify the risk and potential mitigations".[127] PG&E understands the importance and should increase their participation. This activity should be described and listed in this RAMP filing as a control or mitigation.

The learning and products of working with national laboratories and universities should also be captured and implemented. It is unclear if PG&E is learning from and implementing change from working with researchers or not. PG&E should actively seek out feedback and work collaboratively with universities, institutes and national labs to further their understanding on risk and consequence analysis.

[126] https://www.risksciences.ucla.edu/nhr3/cec/home

[127] Data Request response FEITA_001-Q01-11 provided by PG&E on August 21, 2020, Question 03

XI. CONCERN REGARDING COMMUNICATION OF RISK AND LEARNINGS NOT SHARED WELL WITHIN PG&E

PG&E highlights that they hold many routine and monthly meetings with senior leadership including the board of directors, line of business executives, vice presidents and senior officers.[128] The disconcerting issue is that there is no discussion of how the risks, lessons learned and status on mitigation is disseminated to every employee at the company. Each and every employee should know the risks in their job and the risks the company has so that everyone can be focused on risk reduction and safety.

Withholding information is not conducive to a healthy safety culture. Employees performing the work and analyzing risks should understand where the decisions come from. This can only be achieved by having transparency. The lack of communication and transparency is clear, during a coordinating meeting regarding scenario analysis the author pointed out many past events to one employee of the EORM team, they indicated that they had not heard of many of the incidents.[129] PG&E employees who are analyzing risks should know about past events.

In fact, Gas Operations has a requirement to share risks, both internally and externally, "Communicating our business operations and potential risks, both internally and externally, to promote openness and transparency with our stakeholders"[130]. This statement implies that meeting minutes and lessons learned from the top-level meetings should be cascaded to all employees and the public. PG&E should abide by their own policies and make information shared at all of the risk meetings openly available.

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[128] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Chapter 2, Section 4

[129] Verbal conversation on October 21, 2020 with PG&E

[130] Gas Safety Excellence Policy located at: https://www.pge.com/includes/docs/pdfs/safety/gassafety/pipeline/Responsible_Care_Policy_Statement.pdf

XII. LACK OF ACCEPTABLE RISK CRITERIA

FEITA was unable to find any discussion on what an acceptable level or risk is (i.e. acceptable probability of injuries, fatalities, pipeline ruptures, power line failures, et cetera) or any timeline to develop acceptable risk criterion to determine what level of safety is acceptable.

Unless defined quantitatively, risk determination is based on one's own experiences and beliefs. Risk perception will change based on experiences. For example, a new driver might believe they are safe at the time they start driving, but as they gain more experience and age, they may look back on their early driving days as unsafe. Due to the subjective nature of risk perception it is more advantageous to define risk as a quantitative number that is not subject to the beliefs of an individual or company. Qualitatively, what one person or company determines to be safe, another might determine to very risky, a quantitative number removes the subjective component.

The very definition of what safe means to PG&E is absent from the RAMP Report.

The United States and California both are silent in the regulations and code requirements of what is safe or what is an acceptable risk level. Because the regulations do not require it does not mean that companies cannot internally define it or hold themselves to the level of international standards. The United Kingdom as well as the Netherlands have laws that require an organization that creates a risk to manage and control the risk to as low as reasonable practice, which are defined with quantitative numbers. Many companies that fall under Occupational Safety and Health Administration (OSHA) Process Safety Management[131] have their own acceptable risk level, which are generally proprietary and not shared publicly.

[131] 29 CFR 1910.119 - Process safety management of highly hazardous chemicals

A. QUANTITATIVE RISK MODELS PG&E DEVELOPED ARE NOT QUANTITATIVE RISK ASSESSMENTS AND DO NOT PERFORM ACCURATE CONSEQUENCE MODELING

PG&E claims that "PG&E has met its goal to quantify all risks in its Corporate Risk Register except for two (Business Model Risk-Gas and Business Model Risk-Electric). Completing the modeling of these risks required the development of new skills, techniques, and data sources."[132] The quantitative risk assessments (QRA) defined by PG&E do not corelate to well established and understood definition of QRA by industries.[133] A QRA performed on an asset will provide the probability of failure as well as consequence of that failure.

Common outputs of a QRA (performed on a single component, whole facility or along the path of a pipeline) typically include the probability of failure, contours of thermal radiation from fire, contours of explosion overpressure, individual risk of fatality (i.e. probability of death for an individual) based on specific location, societal risk (frequency/number of fatalities and potential loss of life) all of which will indicate if risks are tolerable, as low as reasonably practical or need further risk reduction activities.

A QRA can provide explosion pressure contours to show the extent of explosions. Pressure from an explosion can destroy buildings and impact personnel, if you

[132] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 2-10

[133] American Institute of Chemical Engineers, Guidelines for Chemical Process Quantitative Risk Analysis, Second Edition (New York, Wiley,2000). Also see https://www.dnvgl.com/Images/Introduction%20to%20Quantitative%20RisK%20Assessment%20Webinar%20-%20slides_tcm8-99019.pdf for an introduction of QRA.

know the extent you can plan accordingly (either stronger buildings or place them further away).

QRAs can also provide thermal radiation contours of fires (jet fires, flash fires, et cetera) so that personnel and equipment will not be damaged. QRAs can also provide dispersion analysis to determine the flammable envelope or see how gases will disperse. QRAs can be simple or complicated. QRAs can be performed to provide the probability of a fatality on an annual basis for every foot of pipeline. At the very minimum a QRA for each major facility should be performed to see how any incident will impact the surrounding area. QRA results will allow for the highest risk areas to be focused on first. Process safety does this work, as discussed above.

B. UNFOUNDED CLAIMS TO DEVELOP NEW SKILLS AND TECHNIQUES

For Gas Operations, their claim of needing to "develop new skills and techniques" are unfounded and wrong. Gas Operations' Process Safety department (PS) has software licenses and personnel who are trained in Process Hazard Analysis Software[134] (PHAST), which is the world's most comprehensive process hazard analysis software.[135] PS personnel have performed QRAs on PG&E facilities as well as have had contractors perform QRAs on facilities such as McDonald Island and Milpitas Terminal.

[134] PHAST training was administered by DNV-GL

[135] PHAST can model steady state of dynamic releases, perform dispersion analysis, model fires and explosions, model blast overpressure contours, model thermal radiation while accounting for topography, weather and atmospheric conditions. PHAST is used by more than 800 companies worldwide and been continuously developed for over 30 years. For more information please visit https://www.dnvgl.com/services/process-hazard-analysis-software-phast-1675

Other industries (chemical, petrochemical, refining and many others) have been using QRAs for many decades to evaluate risk. There is an abundance of books, guidelines, articles, reference material and experienced professionals who have been doing QRA work for over thirty years. There is no need to develop new skills and techniques when they already exist.

C. THE VALUE OF AN ACCEPTABLE RISK CRITERIA

QRAs can provide very important information to assess risk and will provide quantitatively, without any opinion, risk to the public, assets and employees. After a tolerable risk criterion is established a QRA will inform PG&E if their facility is safe enough or needs work, or which specific component is contributing to the risk.

To illustrate this, we can evaluate a fictitious example:

> In this example a gas terminal is located adjacent to a shopping facility and further away is residential housing (although ficiticious many of PG&E facilities can be described this way). The tolerable risk of a fatality of a public person is in this example is 1E-6 per annum. This means that the acceptable probability of killing a public person from an incident is 1 in 1,000,000 per year. A QRA is performed on this facility, using company and industry data to calculate probability of a leak, 2" hole and full-bore rupture as well as probability of ignition for each release scenario. The QRA models the thermal radiation of a fire in each scenario, for each section of pipe, it also models the blast pressure from an explosion, taking into consideration the building congestion. The QRA also models the dispersion of gas without ignition to see if a flammable cloud will migrate to any ignition sources. The results will identify that the buildings within the

facility are expected to collapse in an explosion and some buildings outside of the facility are within too high of blast and thermal radiation zones.

The QRA example results show that the risk to the public of a single loss of life is 3.45E-4, which is two orders of magnitude above the tolerable risk. This shows that this terminal, which utilizes the same controls and mitigations as other parts of the system is not safe enough. The company can mitigate the risk by moving the public further away, install additional engineering controls or additional administrative controls. Additional controls may include increased wall thickness monitoring, lowering the operating pressure, increased automatic shut off controls, replacing the pipe with stronger pipe, et cetera Moving the population further away would be extremely costly and unfeasible. In this example the controls which are adequate for other sections of pipeline were found to be unacceptable at this facility. A QRA will provide granular and location specific risks.

Instead of using only internal employees, PG&E should also consult with QRA experts along with internal experts to create accurate and realistic QRA models. These models can indicate which specific components or what specific section of pipe is causing risk. QRAs will allow PG&E to spend money more accurately to improve risk to a tolerable level.

FEITA would like to see some discussion in the RAMP filing the development of quantitative risk criterion and an implementation strategy. In the absence of quantitative risk, qualitative risk should be calibrated by all parties so that risk levels are agreed to and generally understood by all. QRAs should be performed on all major facilities, pipeline and electrical transmission lines to evaluate the consequences of failure as well as the reliability of the facility and components.

XIII. PG&E SHOULD LOOK OUTSIDE OF THE UTILITY INDUSTRY FOR BENCHMARKING

"PG&E looks forward to collaboration between the other utilities and other stakeholders on the best way to model an event when more than one risk event happens simultaneously".[136] After the San Bruno Incident PG&E Gas Operations benchmarked with other industries such as Alaska Airlines, Eastman Chemical and others. It is unclear if looking at other industries was a unique experience or if PG&E is continually benchmarking with other companies. If they are not, they should be and they should be state what they have learned and what changes were made from benchmarking.

The RAMP Report is silent on what learning and improvements they have gained from benchmarking other industries. Best practices from other industries can improve safety, controls and mitigations. The RAMP Report must include lessons learned and benchmarking to provide a total picture of what PG&E is doing to continually improve.

XIV. COMMENTS ON ALTERNATE SCENARIO ANALYSIS

TURN, MGRA and FEITA all requested PG&E to perform alternate scenario analysis. Here FEITA will discuss the requests their own requests and not discuss the other intervenor's request. It should be noted that FEITA agrees with and supports all requests made by others. FEITA is not commenting on their requests because it would be redundant.

In many instances PG&E ignored what was asked and also have not produced results on requested scenarios. Because of the delays, and lack of results, these comments are preliminary.

[136] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 2-15

A. PSPS AS A RISK

PSPS is a risk to customers and society, this is discussed extensively above in this document. This alternate scenario was requested for PG&E to assess the financial and safety impacts of PSPS.

The approach by PG&E to analyze safety impacts of PSPS was utterly disappointing. They approached the scenario by reviewing all bodily injury claims from PSPS events in 2019. This is wrong for many reasons. The first being that most ratepayers probably do not even know they can make a bodily injury claim. PG&E did not do a great job to even tell people a PSPS would occur and face potential fines because of their lack of communication. PG&E does not advertise that a customer can claim a bodily injury claim. The data source is not good. Secondly PG&E failed to look at any data sources outside of their company. They should have reviewed police and traffic incident reports, CalTrans incident reports, FAA incident reports, et cetera. FEITA requested PG&E to look at the safety impact of increased crime rates but ignored this request. The claim of "PG&E has no data to support that PSPS resulted in serious injuries" is very misleading when you don't even look at all the sources.

PG&E believes that the "the indirect financial impact for customers are already captured through the Reliability attribute of the MAVF. Including additional financial losses would lead to double-counting". This is incorrect and another example of the incompetence of PG&E. FEITA provided many examples in the request such as:

- Food spoilage in homes
- Restaurant loss of customers

- Business loss of customers
- Factories shut down and lost production to restore equipment
- Research laboratories and universities losing years of research from loss of refrigeration

None of these are included in PG&E's modeling. PG&E blatantly ignored this request. PG&E converted the reliability impact into dollars to justify ignoring the request. There are studies that show power shut offs result in enormous financial impact, much higher than what PG&E is estimating (around $1 per CMI). The folly of using CMI as a reliability unit is discussed above. CMI does not account for duration per customer or total customers, CMI can be highly misleading. PG&E is woefully underestimating the impact from PSPS and refuses to analyze it, even when requested.

B. WILDFIRE RISK INCLUDING ALL SOURCES OF IGNITION.

In PG&E's definition for wildfire risk they include all activities that can cause a fire, but then they exclude everything but electric asset failures. This scenario was requested to perform an analysis of risk to PG&E's definition and include all possible sources of ignition. This analysis is outstanding and will greatly increase the risk of wildfire.

C. WILDFIRE RISK INCLUDING GAS RELIABILITY AND FINANCIAL IMPACT

In this alternate scenario FEITA requested PG&E include the financial and reliability impact to gas and generation assets in the current wildfire risk model (i.e. cost to rebuild, employee and contractor time to inspect and decommission, engineering costs, etc.). This was requested to show that how PG&E treats financial, gas reliability and electric reliability attributes in their MAVF is wrong, the attributes are related and not separate.

D. WILDFIRE RISK DUE TO GAS ASSET FAILURE

FEITA requested that PG&E run a scenario that includes the risk of a gas asset failure to start a wildfire. During a workshop FEITA asked PG&E if a gas asset could cause a wildfire, Vncent Tanguay answered that it could and didn't see why it shouldn't be included in the wildfire risk. PG&E calculated the total risk score from a gas wildfire was 9. This shows that the risk of a wildfire from a gas loss of containment event is significant.

PG&E's analysis is somewhat conservative and underestimates the risk. A gas line release with ignition releases a tremendous amount of energy compared to a downed power line. Flames can be hundreds of feet tall. The large flames produce immense thermal radiation which is much more likely to ignite everything in the surrounding area. A gas release serves as a better ignition source than a downed power line. PG&E did not consider this.

In the RAMP report PG&E excluded all activities except electrical asset failure in the wildfire risk. This analysis shows PG&E was wrong to do so and is underestimating their total risk of wildfire events.

E. TRANSMISSION LOSS OF CONTAINMENT

For this alternat analysis FEITA requested that PG&E perform the following analysis. The results are still outstanding and FEITA can only comment on the expected results.

PRELIMINARY COMMENTS

1. To perform a consequence analysis using a more realistic potential impact radius (PIR). PG&E used a PIR base on thermal radiation of 5,000 BTU/h/ft^2. This irradiance is extremely high and well above typical values used for emergency operations with PPE. Thermal radiation of 2,000 Btu/h/ft^2 is commonly used as a design criterion for persons, wearing appropriate clothing, are required to perform emergency actions lasting up to 30 seconds without radiant shielding.[137]

   This scenario was requested to because the thermal radiation PIR PG&E used does not capture safety effects to the public. They are not accounting for injuries, property damage and fatalities from thermal radiation properly. Decreasing the allowable thermal radiation will increase the PIR and increase the consequences of a LOC. This will increase the risk of a pipeline rupture.

2. Currently PG&E is adding 9 persons in a PIR if the rupture is near a highway. PG&E did not account for traffic populations and assumed a uniform modifier across all pipelines. This is incorrect, see the loss of containment section below for a calculation showing how this can be very optimistic. The data for traffic populations is readily available from CalTrans. In many cases this will result in a much higher population and result in greater risk. In other situations, the population will decrease and risk for that line will go down.

[137] See American Petroleum Institute Standard 521, Pressure-relieving and Depressuring Systems, Table 12 on Page 106, "Recommended Design Thermal Radiation for Personnel"

F. INDIRECT CONSEQUENCES

FEITA discussed at length in this document (above) how indirect consequences must be considered. FEITA requested PG&E to perform an analysis including indirect consequences, this analysis is still outstanding. Inclusion of indirect consequences and financial losses to customers from outages will greatly increase the risk scores of some scenarios.

G. NATURAL DISASTERS

PG&E describes their risk governance structure and oversight to include risks of other natural disasters[138] but has neglected to include three large scale natural disasters that will impact PG&E assets that have been excluded. PG&E has not discussed volcanic activity, geomagnetic storm or an ARkStorm event and how PG&E plans to have contingency plans in place to mitigate damages and impacts to the public. FEITA asked PG&E to perform a rough analysis to analyze these risks.

1. VOLCANIC ACTIVITY

California contains 12 volcanos that have been ranked as either very high, high or moderate threats, many of which lie in or are adjacent to PG&E service territory.[139] PG&E was an established company when the Lassen Volcanic Center last erupted between 1914-1917[140], so volcanic threat

[138] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page Page 2-3

[139] https://www.usgs.gov/observatories/california-volcano-observatory

[140] In May of 1915, however, partially molten rock oozing from the vent began building a precarious lava dome. The dome collapsed on May 19 sending an avalanche of hot rock down the north flank of the volcano. Three days later, a vertical column of ash exploded from the vent reaching altitudes of 30,000 feet. The ash column spawned a high-speed ground flow of hot gas and fragmented lava. Ash from the top of the column drifted downwind 200 miles to the east, as far as Winnemucca, NV. On both days,

should not be a new risk to the company. Their company archives should detail the damage from the last eruption. A hazard map of the Lassen Volcanic Center shows that Lake Almanor (PG&E hydro) as well as Burney (PG&E Gas Compressor Station) show that they (along with electric transmission lines and gas backbone pipelines) lie well within the danger zone.[141]

2. GEOMAGNETIC STORM

A solar storm on the sun can result in a solar mass ejection, which interacts with the earths magnetosphere causing a disruption. This disruption can damage electric infrastructure. In September 1859, the largest geomagnetic storm on record was observed by British astronomer Richard Carrington, this event is known as the Carrington Event. The Carrington event resulted in auroras seen all over the world, as far south as the Caribbean, and damaged the telegraph systems across the globe.[142] A Carrington level event is almost inevitable in the future.[143] The duration of outages from a Carrington level event (16 days to 2 years) will largely depend on the availability of spare and replacement transformers.[144] The direct costs to

melting snow fueled mudflows, flooding drainages 20-30 miles away. Description of the event cited from https://www.usgs.gov/volcanoes/lassen-volcanic-center. Pictures and

141 https://pubs.usgs.gov/fs/2000/fs022-00/

142 Odenwald, Sten F.; Green, James L. (July 28, 2008). "Bracing the Satellite Infrastructure for a Solar Superstorm". Scientific American

143 Lloyd's and Atmospheric and Environmental Research, Inc. (2013). Solar storm risk to the north American electric grid (PDF). With input from Homeier, Nicole; Horne, Richard; Maran, Michael; Wade, David. Lloyd's. Retrieved July 31, 2019.

144 Lloyd's and Atmospheric and Environmental Research, Inc. (2013). Solar storm risk to the north American electric grid (PDF). With input from Homeier, Nicole; Horne, Richard; Maran, Michael; Wade, David. Lloyd's. Retrieved July 31, 2019.

repair damages could be in the billions, indirect costs and societal risk could be greater.

3. ARKSTORM

The largest recorded flood in California history occurred between November 1861 and January 1862, with larger floods discovered in the geologic record. The United States Geological Survey (USGS) calls large atmospheric events that cause widespread flooding, ARkStorm events.[145] Geologic evidence shows that truly massive floods, caused by rainfall alone, have occurred in California every 100 to 200 years.[146] The 1861-62 flood was devastating, the economy of California was destroyed. USGS simulations show that a similar event would flood most of the central valley, where PG&E has their backbone gas transmission lines, gas storage reservoirs, power plants and power lines, would be flooded. Similarly, lakes and rivers would be overwhelmed and hydroelectric generation would be in danger. Losses would be in the tens of billions.

4. NATURAL DISASTER RISK ANALYSIS IMPROVEMENTS

On October 21, 2020, PG&E presented their risk analysis of ARkStorm, geomagnetic storm and volcanic activity. PG&E admitted it was a very course analysis, around a ±100% analysis. A course analysis is adequate but the analysis contained many errors and erroneous assumptions which resulted in underestimating the risk.

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[145] https://www.usgs.gov/centers/wgsc/science/arkstorm

[146] Ingram, B. Lynn (19 January 2013). "California Megaflood: Lessons from a Forgotten Catastrophe". Scientific American.

I. VOLCANIC ACTIVITY ERRORS

PG&E's course analysis resulted in a risk score of 6.4, which is not insignificant. It becomes more significant if the errors are corrected and if safety is assessed with reliability. The following errors are identified with comments on how each would affect the risk score.

A. Reliability impact to gas is highly underestimated. PG&E supplies around 4.4 million gas customers.[147] PG&E has two backbone gas transmission lines, Redwood Path (Line 400 and Line 401) and Baja Path (Line 300A and Line 300B), Redwood path has much greater physical capacity compared to Baja path. Redwood path has 1.77x the capacity of Baja path.[148] At worst case, this risk analysis assumed that damage to redwood path would result in only ¼ of customers being impacted and at median case only 1/16 customers would be affected.[149]

A loss of a compressor station or damage to Redwood path would be catastrophic. PG&E regularly flows much more gas on Redwood than Baja.[150] Redwood is so important; PG&E has previously floated the idea to decommission Baja and supply the entire gas system by Redwood (and storage). It would result in millions of customers, both residential and commercial, without

[147] https://www.pge.com/en_US/about-pge/company-information/profile/profile.page

[148] Redwood path is composed of 36" and 42" pipe with a firm design capacity of 2,021million cubic feet per day. Baja path is composed of 34" pipe with a firm design capacity of 1,140 million cubic feet per day. These design assumptions assume that compressor stations are at 100% capacity, which is unlikely. For more information see https://www.pge.com/pipeline/about/index.page

[149] PG&E alternate scenario analysis discussed in a coordination meeting on 10/21/20

[150] For daily and historical flows see https://www.pge.com/pipeline/operations/cgt_pipeline_status.page?

gas supply for months or even longer. The loss of a backbone line would be far reaching and is not correctly analyzed in this risk analysis.

B. Reliability impact does not account for criticality of customers, safety and secondary impacts. FEITA discussed above how safety and which customers can have enormous impacts.

C. The financial replacement costs of equipment are very low and unrealistic. Correcting this will increase the risk score. For example, a value of $10 Million was modeled to replace a gas compressor station. The most recent compressor station replacement cost, Burney K-2, was over $96 million and no compressor station is less than $21 million.[151] PG&E's recent bankruptcy case showed that over $14 million was spent on a single contractor for engineering and design alone. Similarly, the cost of a regulator station replacement, $2.5 Million, and mile of transmission pipe replacement, $15 Million, are much lower than current costs.

II. GEOMAGNETIC STORM ANALYSIS ERRORS

PG&E's course analysis resulted in a risk score of 0.1, because of modeling errors. This risk becomes much more significant if the errors are corrected and if safety is assessed with reliability. The following errors are identified with comments on how each would affect the risk score.

[151] PG&E 2018 Annual Report Page 508

A. When FEITA requested a geomagnetic scenario to be conducted it was requested to analyze a storm with a Disturbance Storm Time (Dst) of -1275 nT.[152] PG&E analyzed a much weaker storm of Dst -800 nT. This results in much less impact. PG&E did not analyze what was requested.

B. In the analysis PG&E stated that the electric transmission system is designed in accordance with NERC standards TPL-007 and EOP-010, which would protect the transmission system. TPL-007 is only a planning requirement and contains no design criteria for physical construction of equipment. EOP-010 is to put in place operating plans and procedures, again no design criteria. Both NERC standards only apply to greater than 200 kV. Including all voltages below 200 kV will greatly increase the risk score.

C. PG&E was unaware if the electric distribution system was designed to the NERC standards. It goes without saying the distribution system would be severely impacted. No analysis to the distribution system was included with the risk analysis. This should be included and will increase the risk score.

D. PG&E assumed that every high voltage substation has a spare transformer(s). These are multi-million dollar, long lead items, having a spare for every transformer is a lie and not feasible. It is clear whoever did this analysis was untrained in the sparing

[152] Email sent to PG&E on September 16, 2020

philosophy of PG&E. This assumption leads to overly optimistic safeguards which drastically lowers the risk score.

E. This risk analysis excluded all damage to the telecommunication and control systems. A large geomagnetic storm would impact SCADA communications, leaving the control centers blind to current status and unable to send commands to the equipment, a huge risk. A large storm would also impact cellular and internet traffic, leaving employees unable to communicate in an emergency, another huge risk. Also, the control systems controlling the equipment would be damaged. This would lead to widespread damage and releases, which again would be catastrophic. Gas compressors, especially electric driven ones, could be damaged leading to long outages on the backbone system.

III. ARKSTORM ANALYSIS ERRORS

PG&E's course analysis resulted in a risk score of 6.9, which is not insignificant. It becomes more significant if the errors are corrected and if safety is assessed with reliability.

A. The ArkStorm analysis ignored flooding damage to many compressor stations and major gas control facilities such as Antioch Terminal, Brentwood Terminal and Milpitas Termina. Most of the Redwood path compressors located in the central valley would be exposed to flooding greater that 14 days.[153] Kettleman Compressor Station on Baja path could be exposed to flooding between 3-14 days as well. The impact to the entire backbone system and to the gas terminals would be unimaginable for gas customers. The outage could last months or longer with nearly all customers subject to the inspection and relight process. This will greatly impact the reliability risk score, financial score and when the safety of reliability is included the safety score.

B. Costs for damage and repair to equipment are very low. $300,000 to repair one compressor station is almost laughable at the optimism. PG&E has spent over $250,000 to replace a single 2" valve on a regulator station in the past, $300,000 to repair a compressor station that was flooded for two weeks is orders of magnitude too low. Using realistic numbers will increase the risk score.

C. The risk analysis ignores the impact to SCADA control and communication. A flooded station will impact communication, especially high traffic nodes such as Brentwood Terminal. It has been said that the Brentwood terminal flows 1/7th of the gas SCADA information through it. If Brentwood is under water, 1/7th of the gas system will be operating blind. A large risk that is unaccounted for.

[153] https://www.usgs.gov/centers/wgsc/science/arkstorm?qt-science_center_objects=0#qt-science_center_objects

D. Many of the natural gas storage facilities are located in flood zones, both independent facilities and PG&E owned and operated ones. PG&E's largest facility, McDonald Island is built on platforms because the ground is its built on is over 20 feet below sea level. It has been designed for a levee break flood (which one did occur in 1982) but not more. An ARkStorm will being much higher levels than sea level to the delta area. An ArkStorm may result in enormous damage to gas storage facilities that could take a year or longer to repair. Gas storage issues could result in gas shortages in the winter which is both a reliability and safety risk.

E. PG&E did not include the risk to hydro assets because they have already been captured in a large uncontrolled water release. The risk during an ARkStorm is that the damage and risk to all lines of business occurs at the same time. Risk is increased when gas, generation and electric have outages and damage at the same time. Employee resources will be understaffed to handle a total system failure. This compound effect should be considered and not ignored.

IV. NATURAL DISASTER PREPARATION

The three natural disasters described above are not hypothetical scenarios, they have all occurred and will occur again. California has a rich history of wildfires for thousands of years, but it took asset failure and the deaths of people for PG&E to realize the risk of natural disasters. PG&E should not fail to prepare for other natural disasters that will greatly impact their assets.

These are very high-risk events that PG&E must prepare for. The damage to PG&E assets, without preparation could leave people without gas or electric service for an extended amount of time, perhaps even years, which is a huge risk to the ratepayers. All events will give warning signs, from a few days to months in advance. At the very minimum contingency and emergency plans should be developed. Flood maps which identify assets should be developed. PG&E should work with the USGS offices to determine the risk and how to safeguard equipment from volcanic events. PG&E should understand how to limit damage from a Carrington level event.

XV. CONCERNS ABOUT SAFETY CULTURE

Culture and safety culture are the manifestations of behaviors and beliefs of individuals. This means that the safety culture at PG&E is determined and nurtured by those at the top of the organization. Concerns around competency are also shared with concerns around safety culture.

A. PROCESS SAFETY LEADERSHIP ARE NOT FIT FOR DUTY

On July 26, 2019 the Office of the Safety Advocate provided prepared testimony on PG&E's 2020 GRC. In this testimony they testified that the Director of Gas Safety, Quality and Support as well as the Manager for Process Safety were not trained or qualified for their positions. [154]

Through a data request FEITA requested completed training completed or safety certifications completed by the Manager of Process safety and the Senior Director of Safety, Quality and Contracts Management (the same individuals the OSA identified as being undertrained. PG&E objected to this data request and said it is

[154] A.18-12-009 Exhibit Number OSA-01

not relevant to RAMP.[155] It is clearly relevant to the chapter on Safety Culture because as the OSA eloquently testified "Individuals that lead safety departments with no experience or training in safety introduces potential risk to an organization. This lack the safety experience makes it difficult to influence positive culture change."[156]

This data request is directly relevant to safety culture. This objection to the data request exemplifies PG&E's laissez faire attitude toward safety culture and also risk. Most likely these two individuals have received zero relevant training since the OSA testimony. Instead of training, PG&E just promotes individuals, it should be noted that since the OSA testimony, the Director has been promoted to Senior Director.

B. MUTUAL AID AND CULTURE

- Mutual aid responders are not trained to PG&E standards. Could result in repairs that do not meet CPUC requirements and will fail in the future.

C. EXAMPLE OF POOR CULTURE DURING WORKSHOPS

PG&E uses RSI Guard, a computer software program to reduces the impact of repetitive strain injuries (RSI) for office workers.[157] RSI Guard will 'pop-up' and force people to take a break. This is done for safety. A good safety culture would always take a break when needed. During one workshop the lead RAMP manager and also a Senior Manager of the Enterprise Operational Risk Management department had a RSI Guard pop-up, instead of taking a break and taking the time

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[155] [155] Data Request response FEITA_001-Q01-11 provided by PG&E on August 21, 2020, Question 2

[156] A.18-12-009 Exhibit Number OSA-01

[157] https://www.rsiguard.com/

(1-3 minutes) to discuss repetitive strain injuries (to promote a good safety culture) the Senior Manager tried to disable the software. This is an example of PG&E saying one thing such as they have great systems to reduce risk but do not follow or enforce their safety systems.

[further discussion on culture to be developed]

XVI. GAS LOSS OF CONTAINMENT

[not completed – bullet points provided]

- Probability of ignition is inaccurate, assumes equal throughout the territory. It will vary based on sources of ignition (power lines, public, vehicular traffic, unrated electrical systems (street lamps, traffic signals, etc.), wind, release rate, atmospheric conditions, congestion of buildings, etc.
    - Probability of ignition should be calculated the way PG&E calculated probability of ignition when performing the QRA at Milpitas terminal.
- Missing most obvious mitigation – lower operating pressure to reduce probability of failure. Should be included in alternate analysis (7-30)
    - Lowering the pressures will increase the spread between the burst pressure and operating pressure. PG&E has shown that pipelines operating below 20% of the specified minimum yield stress are more likely to leak and not rupture. There is no discussion in any control or mitigation presented in Chapter 7 to reduce operating pressures.
    - A study should be conducted based on measured pressures and whether to develop accurate gas system models that allow for the operating pressure in the lines to be adjusted according to demand rather than always operate near MAOP and pack the line with as much gas as possible at all times.

- Check valves are not maintained, there is no standard to maintain them
- If a valve is leaking, packing with grease to stop the leak doesn't address the root cause of leaking
- Internal corrosion is listed separately than SCC. SCC is a specific type of corrosion; it should be included with corrosion. (Pages 7-1 and 7-3)
- This risk ignores land movement risk. Land movement will put stress on the pipeline increasing the probability of rupture. PG&E should have some ground monitoring stations to track movements along with strain gauges installed on the pipe to corelate round movement to pipe stress and strain.
- PIR ignores traffic data and population in vehicles. "impacted occupancy count with 10 or more people within the potential impact radius" – This does this take into consideration the number of people on the road. For example, the backbone lines travel parallel to HWY 5 but there are no houses in the vicinity. According to CalTrans data the roads (traffic census data) will show that on average there are more than 10 cars in the impact radius. This method severely underestimates the risk of rupture. (7-14)
    - PG&E included traffic census populations when they performed the QRA at Milpitas Terminal. It is illogical to include it only when convenient. Many transmission lines run parallel to highways and interstates. Many of the lines do not have homes or businesses in close proximity and as a result are currently excluded in the potential impact radii. The average population on roads may contain more people than a single home would. PG&E is excluding a significant portion of the population and significantly underestimating the risk profile of transmission lines.

      For example, in 2017, HWY-880 at Mile Marker 10.407 (Dixon Road) had an annual average daily traffic volume of 225,000 vehicles. A vehicle traveling at 65 miles per hour would cover 220 yards in approximately 6.92 seconds.

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California Vehicle code does not give specific distances for safe spacing between vehicles. Assuming 2.5 seconds between cars would show that there are approximately 2.8 cars per lane per direction of travel within a 220-yard radius of a rupture. Highway 880 is five lanes in each direction at Dixon Road, which would give an average annual approximation of 27 to 28 vehicles within a potential impact radius. It is difficult to estimate vehicle occupancy but assuming 1.5 persons per vehicle would give an annual average population that could be impacted by a pipeline rupture on Highway 880 at Dixon Road is 41 to 42 people. Anyone who has travelled on 880 during commute times knows that 65 mph is a fantasy. During commute times (assuming 10 mph with 20 ft following distance and 1.5 persons per car) the potential impacted population could be estimated at around 500 persons. Clearly the population from roads and highways is not insignificant and should not be ignored. Caltrans collects and publishes traffic counts through their traffic census program. This data should be utilized by PG&E in their risk models. Ignoring the population that could be affected by a pipeline rupture is significant and using this data will show that pipelines pose much more risk to populations than PG&E is estimating. Besides the direct impact of injury and death, shutting down or damaging a highway, California State Route or Interstate would also come with significant secondary consequences

- ILI has the highest risk spend efficiency scores and highest total reduction scores (7-2). ILI does not reduce any risk. ILI only allows for inspections, the inspections themselves do not reduce risk. The risk to the pipeline from leak or rupture is not influenced by inspections. Only if the data is properly interrupted and the inspections find areas of concern and then those corrections are corrected would that reduce risk.
- Table 7-1 – why specify 1984 dollars and not calculate to current values? For a loss of 50,000 1984 dollars how much gas in scf would that equate to?

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- 7-5 "use PG&E data where available" how much of the data is unavailable? Should specify which pipes use non PG&E data.
- Chapter 7 only focuses on transmission pipe. Transmission facilities are made of the same material, there is not a piping change at the fence line of the facility. Transmission facility piping must be included in the risk for transmission pipe LOC. All miles of transmission facility pipeline should be included? Transmissions stations and terminals are often closer to populations (Milpitas Terminal is in a shopping center between multiple freeways and hotels, Brentwood Terminal is next to a housing development, Irvington Station is next to a freeway, church, school, hotel and businesses, et cetera) and potentially is higher risk than transmission pipe. Transmission station piping is not pigged or inspected like transmission pipe is. PG&E should include transmission stations in their risk models.
- How does the model account for variations in soil chemistry, soil resistivity, marine environment, etc.
- 7-5 – data based on PHMSA – how is the PHMSA data screened or adjusted to account for California conditions? RAMP should discuss how Midwest and east coast data corelates to California and varying local geographic situations.
- 7-6 seismic accounts for 27% of the risk. Can you identify the seismic related issues that have occurred in the past on PG&E pipeline? How is 27% justified.
- 7-8 "The stress ratio of 20 percent SMYS equates to a factor of safety equal to five, which means the maximum pressure the pipeline could hold without failure is five times the specified Maximum Allowable Operating Pressure" This statement is incorrect. MAOP is not based on the maximum yield stress of the pipe (49 CFR 192) it is based on what pressure it was tested to and derated for the class location.
- 7-12 - Gas Transmission risk team discussed the potential impact that wildfires could have on this risk and concluded that the impact would be small given that transmission

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pipeline assets are mostly underground. Was a heat transfer calculation performed to verify this claim?

- No risk of projectile is identified. A large piece of pipe or rock can kill someone. PG&E uses set back distances in the thousands of feet for pneumatic test (based on calculation and destructive testing). Risk of impact from debris should be included in financial and safety.
- LOC also results in greenhouse gas emissions. PG&E claims to account for environmental impact in financial but there is no accounting for enormous greenhouse gas releases
- Existing algorithms to identify leaks have failed in the past. Line 215 rupture was detected by an employee living nearby who heard it and called the gas control center. The control systems did not detect it. They need updating. There is no discussion of improving rupture detection algorithms
- Potential impact radius based on 5,000 BTU/hr/ft^2. This is absurdly high. API 521 and other industries would calculate 2,000 or below for emergency situations, 500 for continuous exposure with appropriate clothing.
- Develop filter sizing criteria. Should be based on flow rate and particulate/liquid design criteria, not solely on pipe size. Sizing properly will allow filters to operate as intended.
- The transmission system should have 100% visibility. Projects should be conducted to install pressure, and where necessary flow, transmitters so that Gas Control Operations can see what is happening, in real time, throughout the system.
- PG&E should update their standards and procedures to state that all new pipe that is installed has an MAOP that is below 20% of SMYS.
- The 2.31 multiplier for property value should be replaced by home insurance data. Insurer data would provide more accurate values of the structure and property. Using Zillow data

is overestimating the cost of replacement. Zillow data is inclusive of the land and structure, not the replacement cost.

The use of housing values should also be weighted by the geographical location. Averages along the pipeline would be easy to do and incorporate into the model. Using a single average across the state is wrong. Using structure replacement values rather than land and structure values should lower the financial risk score that PG&E is currently using in their risk model.

- PG&E should monitor pipeline wall thicknesses in certain locations on an annual basis to measure corrosion rates. PG&E can use these rates in their model to determine when to replace pipes before integrity is compromised.
- PG&E should destructively test pipe that is removed to confirm their integrity models and how they derate pipe for wall loss and corrosion is accurate. PG&E can take the removed section of pipe, hydrostatically test it to failure, then compare the pressure it failed to its calculated failure pressure. If there is a significant difference in pressures then the calculated pressures are wrong (either high or low). If the calculated pressure is higher than the failure pressure it would mean that PG&E is overestimating its pipeline integrity and safety of its transmission lines, this would be a foundational error in the risk model.

XVII. GAS OVERPRESSURE EVENTS

- Discuss MOC around stations to ensure they are always properly sized. Example – Spreckles OP event was due to oversized regulation, regulators were sized for industrial plant and 20 residents, plant was removed and regulation never resized leaving regulation oversized and unable to control for small flow rates.

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- Discuss how dual run isn't a solution for single feed customer. PG&E identified dual run would be installed. If a regulator fails or leaks a second one will not mitigate or even reduce the likelihood of an OP.
- Discuss single feed customer regulation must be designed in conjunction with how the customer operates. Customer can be rapid start/stop, seasonal, have flow pulsations, etc. PG&E only asks for delivery pressure, not how the customer will operate. Knowledge on how they operate will allow regulation to be designed for the flow conditions and not OP or fail on demand.
- Discuss relief devices. PG&E installing reliefs without calculations. This is risky and stupid. Wrongly sized reliefs may not relief when needed. PG&E installing reliefs as secondary OP protection, beyond code requirements. Anything beyond code should not be paid for by ratepayers. If PG&E operated their system properly, beyond code installations would not be needed. This is unnecessary spending. Does not address the root cause of regulation failing.
- No discussion on gas quality issues. Sulfur, Black Powder, Pipeline liquids, Moisture, Dithiazine are all causes of OP (and some corrosion) but are not addressed. Fixing the gas quality issue would be addressing a root cause and negate the need for many mitigations that ratepayers are paying for. PG&E must have a better gas quality program.
- Slam shut devices do not prevent an OP, they only stop it from getting worse. Slam shuts can also lock in the overpressure to the downstream piping. Secondary OPP is extra, not required by code. Anything beyond code should not be paid for by ratepayers. If PG&E operated their system properly, beyond code installations would not be needed. This is unnecessary spending. Does not address the root cause of regulation failing. Does not address the root cause of regulation failing.
- OP in chapter 9 is only downstream of facility. PG&E is ignoring OP within a facility (which has occurred many times). Terminals have varying MAOP and complicated operating modes – OP within a facility must be included.

XVIII. WILDFIRE

- Other intervenors are addressing PG&E's wildfire deficiencies very well.
- PG&E excluding all activities that can lead to wildfire (see scenario analysis comments)
  - Human error
  - Pipe rupture
  - Et cetera
- The root cause is PG&E has equipment installed that is not fit for duty. PG&E should have had design criteria for each equipment that is installed that clearly shows what forces and wind conditions it was designed for. They should have maintained equipment over the years too. The root cause is poor design and maintenance. Nothing in the mitigations addresses the root cause of wildfires.

XIX. REAL ESTATE AND FACILITIES FAILURE

PG&E identified a risk of buildings and facilities that are unsafe, inaccessible to support operational needs from seismic, flood, landslide, building fire or physical security event.[158] 99.8% of the total risk is from seismic activity.[159]

A. SEISMIC IS A KNOWN RISK IN CALIFORNIA

California has a long history of seismic risk. PG&E was incorporated in 1905 and experienced firsthand, as a company, the 1906 and 1989 earthquakes. PG&E knows seismic activity is normal in California, if they build or rented any building that may fail that is on them. PG&E knows its services are vital to its customers and should occupy only buildings that are built to withstand seismic forces.

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[158] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 14-2
[159] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 14-6

B. REAL ESTATE ASSESSMENTS SHOULD NOT BE RATEPAYER FUNDED

PG&E plans to survey buildings to assess their seismic resiliency.[160] Foundational activities to assess the risk should not be funded by ratepayers. PG&E should have assessed seismic risk when occupying or constructing structures. The cost to "re-do" this real estate work is PG&E's responsibility only, it should not be passed to ratepayers to pay for oversights PG&E knew about.

C. PG&E IGNORED EXPLOSION RISKS AND DOES NOT DESIGN BUILDINGS TO API 752 AND API 753

The American Petroleum Institute has two recommended practices for blast resistant buildings, API PR 752 and 753. API 752 is for permanent installations where 753 deals with temporary structures. PG&E and its contractors typically will install jobsite temporary structures during construction. PG&E facilities also will have light wood trailers installed as permanent buildings.[161] These two recommended practices have been developed after tragic explosions killed people who were in buildings that collapsed in a blast. PG&E's gas facilities are more likely to have an explosion than an electric facility. Buildings that are not designed for any blast resistant can easily collapse and kill any occupants. This is a major risk that has been mitigated in other industries by following API 752 and 753. PG&E should review all permanent and temporary buildings for blast resistance. This will save lives.

[160] A2006012 2020 Risk and Mitigation Phase Report, Pacific Gas and Electric Company, Page 14-3

[161] Satellite and street-view pictures detail many facilities that have light wood trailers (portable buildings) installed on a permanent basis. See McDonald Island, Los Medanos, Hinkley Compressor Station for example.

XX. EMPLOYEE AND CONTRACTOR SAFETY

- Discuss how contractor and employee safety should not be different, human life is human life. Contractors are hired to work for PG&E, if contractors were not hired, employees would perform the work with the same risks.
- Contractors should be held to the same standards as employees, trained the same way to ensure the same work is done the same way.
- Motor vehicle miles only include PG&E vehicles
    - Should include contractor milage (discussed at a workshop)
    - Should include milage in rental cars
    - Should include milage in personal vehicles (miles that get expensed)

XXI. RECORDS INFORMATION MANAGEMENT

A. PG&E IS POOR AT DOCUMENTING MEETING MINUTES

PG&E conducts thousands of meetings each day. During meetings important decisions can be made. PG&E does not have any requirement to take meeting minutes. During the coordination meetings for alternate scenario analysis, parties provided PG&E with feedback and information, but no record was kept. Instead PG&E employees relied on memory.

Without reliable meeting minutes employees are ill informed at historical decisions. This decreases efficiency because employees may

B. CELL PHONE DECISIONS ARE NOT RECORDED

PG&E issues a cellular telephone to nearly all employees. Employees use text messaging in place of emails, decisions can and have been made over text messaging. PG&E does not archive and backup text messages like they do with email. PG&E has no procedure on how to document decisions over text message.

The data is maintained by the cellular provider, not PG&E. PG&E should never make a decision without proper documentation and archiving practices.

- Discuss how for projects PG&E has to spend a significant amount of time to search existing records because the existing system is cumbersome.
- Discuss how the document numbering system is cumbersome and not intuitive which also creates issues when trying to locate records

XXII. SAFETY MANAGEMENT SYSTEMS AND THEIR RELATION TO RAMP

Closely related to process safety, safety management systems can greatly improve safety, efficient and reliability of utility operations. The management system should ensure that the design, construction and operation of a utility is consistent, safe and reliable. PG&E has stated that they have been certified in the following management systems:

- American Petroleum Institute Recommended Practice 1173 (API 1173)
- Publicly Available Specification 55 (PAS 55)
- Responsible Care 140001 (RC 14001)

Clearly PG&E understands the importance but has failed to incorporate the systems into RAMP.

The management systems are very important and will significantly improve safety and affordability.

More discussion with PG&E is necessary to fully understand where they are with API 1173 and how exactly, with examples, it will improve safety. For example, a safety-oriented company would not encourage construction contractors to implement a recommended practice, instead they would require that all contractors meet or exceed their own requirements. In fact, API 1173 section 8.4 states that the pipeline operator shall define and document the process for contractors.[162] This statement brings into question how serious PG&E is about implementing

[162] ANSI/API Recommended Practice 1173, First Edition, July 2015

API 1173 and other management systems. There is no discussion of management systems in RAMP and how they will improve safety.

XXIII. MITIGATIONS THAT RATEPAYERS SHOULD NOT PAY FOR

PG&E has identified many mitigations and risk contributions that are due to PG&E's poor manage. Ratepayers should not pay for mitigations that are correcting past oversights, maintenance negligence, and poor management practices.

A. RECORDS INFORMATION MANAGEMENT

Throughout the RAMP report, Records Information Management (RIM), has been identified as a risk contributor. Ratepayers have paid for PG&E to develop records when the project was engineered, constructed and put into service. In many cases PG&E has failed to maintain the record over the years to ensure that it is always current and accurate. Ratepayers should not be burdened with the costs to update existing records. Any projects such as critical documents on the gas side, which creates and updates drawings and other records, should be 100% shareholder funded. Charging ratepayers to re-do records is wrong. PG&E should be financially responsible for correcting their poor records management practices.

1. RECORDS SEARCHES

Time spend by employees to search records for projects (gather existing records) should not be charged to ratepayers. Employees spend a large amount of time at the beginning of projects to perform records searches. PG&E has chosen to have a system where records are not stored and easily accessed. Ratepayers should not pay for employees to search for information that should be readily available.

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2. CRITICAL DOCUMENTS UPDATES

PG&E's failure to maintain critical documentation (drawings, P&IDs, schematics, one-line diagrams, et cetera) should not be funded by ratepayers. Ratepayers funded the projects which included creation or updates to documents. If PG&E failed to update them over the years, that is their expense.

3. ASSET INTEGRITY PROJECTS

Asset integrity projects to ascertain the current status should not be ratepayer projects. PG&E failed to keep records of what they installed and where they installed them, projects paid for by ratepayers. Ratepayers already paid for the original installation, to go verify what PG&E installed should be the burden of PG&E.

B. ILI UPGRADES

PG&E should have designed the pipelines to be pigable when installed. Correction of PG&E's poor design should not be funded by ratepayers.

C. ENSURE EMPLOYEE AND CONTRACTORS COSTS FOR SHAREHOLDER FUNDED PROJECTS ARE NOT RATEPAYER FUNDED

All costs associated with shareholder funded projects should be charged to shareholders. Employees will most likely be working on projects that are funded by ratepayers and some that are shareholder funded. Employees should be accurately recording their time so that the costs can be allocated appropriately (i.e. prorated based on employee time coding). When employees and contractors work

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on shareholder funded projects the total costs associated with them. The costs of the following should never be passed along to ratepayers for shareholder funded projects:

- Workplace costs
    - building rent
    - IT hardware and software
    - IT support
    - heating and cooling
    - network connectivity,
    - phone and telecommunication (desktop and cellular telephones)
    - property tax,
    - etc
- Employee compensation and benefits
    - Salary
    - Bonuses
    - Medical Insurance
    - Dental Insurance
    - Vision Insurance
    - Pension payments
    - Retirement account matching
    - Et cetera[163]

[163] A full description of employee benefits can be found here http://mypgebenefits.com/

- Overhead costs should be pro-rated on a company bases based on total hours spent on shareholder vs. ratepayer funded projects
    - Benefit administration
    - Human Resources
    - Et Cetera

A detailed analysis of projects should be conducted in the GRC to ensure no costs for shareholder funded projects are paid by ratepayers

D. SYSTEM HARDENING

PG&E is funding system hardening projects to fix their past mistakes of not designing equipment to be suited for its environment. PG&E should have originally designed equipment to not fail in weather conditions. This correction should be PG&E's cost to redesign their equipment to not fail.

E. SECONDARY OVERPRESSURE PROTECTION

Secondary overpressure protection is not required by federal code. This is an added expense that PG&E is doing because it cannot safety operate its gas system. Anything extra from code should be shareholder funded.

F. PUBLIC SAFETY POWER SHUT OFF

PG&E has failed the public to install and maintain equipment that does not fail on demand. They should have originally installed equipment that was designed for its environment. All costs of PSPS, including indirect costs to customers, should be paid for by PG&E.

XXIV. SUGGESTED IMPROVEMENTS TO THE RISK MODEL, IDENTIFIED RISKS, DRIVERS, CONTROLS AND MITIGATIONS

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Many improvements have been discussed in context in the above sections. Here is a summary of the suggested improvements to improve how PG&E identifies, calculates and controls risks and hazards.

A. USE OF ADVANCED COMPUTER ALGORITHMS

1. Use machine learning, artificial intelligence in all LOBs to monitor control systems, provide advanced warning, prediction, et cetera
   - Stations that constantly Hi or Hi-Hi alarm can be identified for inspections
   - Sulfur buildup can be detected prior to OP

B. MAVF IMPROVEMENTS

1. PG&E should provide a clear definition of direct consequence and an indirect (secondary) consequence
2. PG&E consider foreseeable and reasonable consequences, regardless of if they are indirect or direct
3. Electrical Reliability units should be based on interruption minutes per customer and total number of customers instead of an aggregated total customer minutes of interruption
4. Gas reliability units should include the outage duration in addition to customer count
5. The reliability attribute should singular “loss of service” based on loss of customers and duration of outage to the customer instead of gas and electric separately
6. The interdependencies of safety, reliability and financial should be analyzed together when evaluating a risk

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7. Criticality and societal importance of customer outages should not be ignored
8. Involve all safety and risk departments in all LOBs to provide input in RAMP
9. Work more collaboratively with recognized experts, universities and institutions
10. PG&E should assess all potential threats and analyze them with the same level or rigor as incidents that have occurred (this is actually a requirement of RC 14001 which PG&E is certified in)
11. PG&E should provide a complete narrative of all activities they are doing to control and mitigate a risk to give the whole picture to all parties
12. PG&E should not ignore any mitigation activities that can improve safety
13. PG&E should provide a narrative of administrative controls they rely on to mitigate or control a risk
14. The risk model should account for the seasonal risk and risk reported by season
15. Consequences should be modeled for their environment, topography and individual situation instead of relying on an incorrect Poisson model
16. PG&E should identify and label each proposed control and mitigation by what type of risk reduction method it is
17. PG&E should strive to develop effective controls that address the root cause of the risk and not prioritize mitigations that only address the local causes
18. PG&E should analyze the safety, reliability and financial risk of each mitigations prior to implementation. Mitigations can result in increased risk.
19. Accurately account for environmental risks
20. Account for environmental impact from wildfires

21. Account for contributions to global climate change
22. Quantify how many protected species are killed each year to establish a baseline to improve upon
23. Implement bird and bat protection strategies near wind generation
24. Identify and account for all realistic indirect consequences for all risk scenarios
25. Establish an acceptable risk tolerance criterion and apply it to all assets
26. Update natural disaster scenario analysis to be more realistic
27. Calculate probability of ignition based on environment and do not use an average for the entire service territory
28. Use Management of change for all changes
29. Address competency issues (below)

C. COMPETENCY IMPROVEMENTS

1. An independent party to PG&E (Federal Monitor, CPUC or other outside firm) review the competency, training, experience and qualifications of each individual on the VP committee to ensure that they are competent to approve the corporate risk register.
2. Qualifications to be a SME must be stated and verifiable to ensure that they actually have expertise in the subject
3. The PG&E training academy should work with all lines of business to identify training requirements by position and enforce said training requirements
4. Train employees when they move positions or change responsibilities for their new role
5. Provide training on all LOBs Vice President Committee members

6. Provide training on all LOBs to EORM employees
7. Perform qualification testing on vice president committee and SMEs to prove competency
8. Provide initial and refresher human performance training to all employees and all contractors
9. Provide initial and refresher process safety training to all employees and contractors
10. Establish a mechanism to test employee competency for each position within the company
11. Train employees and contractors to identify protected species
12. Involve process safety in RAMP
13. Enforce safety management system adherence for all work by employees and contractors
14. Benchmark with non-utility industries
15. PG&E should make additional efforts to reduce relying on SME from the beginning of the risk selection process

D. GAS LOSS OF CONTAINMENT

1. Lower the operating pressures within the transmission system.
2. Remove all indoor meter sets from customers property
3. Establish a filter sizing criterion.
4. Actively monitor all filter differential pressure
5. Develop gas filter sizing criteria
6. The transmission system should have 100% visibility in real-time

7. PG&E should update their standards and procedures to state that all new pipe that is installed has an MAOP that is below 20% of SMYS.
8. The 2.31 multiplier for property value should be replaced by home insurer data to accurately model the replacement cost of property
9. PG&E should include transmission stations in this identified risk.
10. PG&E should monitor pipeline wall thicknesses in certain locations on an annual basis to measure corrosion rates.
11. PG&E should destructively test pipe that is removed to confirm their integrity models and how they derate pipe for wall loss and corrosion is accurate.
12. Use a PIR based on a safe thermal radiation irradiance that will ensure no serious injuries or fatalities
13. PG&E should recognize the seasonality of risk.
14. Implement pipe and wall thickness monitoring program in gas
15. Include risk of projectiles in gas loss of containment events
16. PG&E should have some ground monitoring stations to track movements along with strain gauges installed on the pipe to corelate round movement to pipe stress and strain.
17. PG&E must include the population from traffic in the consequence analysis.

E. GAS QUALITY IMPROVEMENTS

1. Update contracts with California producers (some may be 80 years old) to eliminate unwanted components in the system
2. Remove H_2S and other sulfur, dithiazine, moisture, et cetera at interconnection points to safe levels

3. Develop a robust water quality specification, with corrosion inhibitors, to ensure any water for hydrotesting will not cause issues
4. Remove all liquids injected during ILI (diesel, methanol, et cetera), do not leave any unaccounted for
5. Remove all liquids after hydrotesting, do not leave any unaccounted for

F. LARGE OVERPRESSURE EVENT DOWNSTREAM OF MEASUREMENT AND CONTROL FACILITY

1. Review all installed relief devices to ensure that they are calculated in accordance with API 520 and API 521
2. Design regulation equipment based on how the customer operates
3. Improve gas quality issues and construction practices so there is no debris, particulates or troublesome gases in the line that can cause an OP
4. Lower operating pressures as much as possible
5. Understand how single feed and large volume customers operate and design equipment to meet those operational needs.
6. Do not install any equipment (relief valves) that have not been calculated to be correct sizing and will perform as intended
7. Accelerate SCADA installations to have 100% visibility

G. WILDFIRE

1. Include all assets and all activities as risk drivers. Focusing only on electric assets ignores the risk from employee and contractor activities, portable equipment, gas assets and generation assets. Ignoring all sources of ignition is wrong.

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H. RECORDS INFORMATION MANAGEMENT

1. Take meeting minutes for all meetings and have a numbering and archiving system
2. Develop process to document and archive text messages and decisions made over text

I. EMPLOYEE SAFETY INCIDENT

J. CONTRACTOR SAFETY INCIDENT

1. Contractors should take the same training courses and access to the same standards as PG&E personnel

K. REAL-ESTATE

1. Include blast overpressure risk (which will require blast probability and calculations at facilities) for all structures (see API 752 and 753)

L. MOTOR VEHICLE SAFETY INCIDENT

1. Include all miles driven by PG&E or on behalf of PG&E
    a. Contractor miles
    b. Rental car miles
    c. Personal vehicles miles for business trips and commute miles

M. PROCESS SAFETY

1. Perform QRAs along the profile of the pipeline to calculate societal risk along the pipeline
2. Perform QRAs at all major and critical facilities
3. Perform QRAs on electrical line failures
4. Develop a robust system to track and monitor all PHA recommendations

5. Analyze the reliability and adequacy of safeguards

XXV. CONCLUSION

The risk framework and methodology presented in the RAMP Report is highly subjective, contains many questionable assumptions and omits many risks and mitigation activities. It can be easily manipulated by the "subject matter experts" who provide input into the ranking. PG&E's risks and RAMP report have been approved and developed by persons who have no training, qualifications and no experience in risk. A significant amount of work is required to update the framework that will allow for repeatable and reliable risks that will better suit the ratepayers and environment.

The comments provided in this document are preliminary and are incomplete. It is being provided to aid others in their analysis.

APPENDIX 3

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2020 Risk Assessment and Mitigation Phase Report	Application A.20-06-012 (Filed June 30, 2020)

MUSSEY GRADE ROAD ALLIANCE INFORMAL COMMENTS

ON THE PG&E RAMP SCENARIOS

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Dated: November 2, 2020

1. INTRODUCTION

These informal comments are prepared by Mussey Grade Road Alliance expert Joseph Mitchell at the request of SPD[1] to be used as input in their analysis of the PG&E RAMP report.

MGRA has been actively working with PG&E and other parties to develop alternative RAMP assumptions regarding risk, tranches, and RSEs. We were most specifically involved in:

- Alternative assumptions for the Multi-Attribute Value Function (MAVF), including removal of capped losses and also non-linearity of response.
- Using wind speed as a tranche delimiter, with and without the presence of National Weather Service Red Flag Warnings.
- Development of the requirements for Public Safety Power Shutoff as a risk and not merely a mitigation.

Additionally, we have interest in and comment on the wildfire tranche analysis requested by TURN.

2. ALTERNATIVE PG&E RAMP ANALYSES – MGRA

The following analyses were those in which MGRA was involved closely with the proposal and vetting of the analysis. Only one (wind tranches) was explicitly sponsored by MGRA alone, but we were involved with the others as well.

2.1. Multi-Value Attribute Function

MGRA originally proposed a multi-value attribute function variant for PG&E to analyze, but our proposal was similar enough to the TURN-02 that we withdrew our proposal.

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[1] Email from Steven Haine, Safety Policy Division; PG&E RAMP scenario run results; September 23, 2020: "One thing I'd like to know from parties is how will parties compile the results from the sensitivity/scenario runs and present the results to SPD. In order for the results to be useful to SPD's evaluation report, the results should be interpreted by the corresponding parties and then "packaged" and delivered as informal comments to SPD."

As background to this analysis, MGRA had expressed skepticism regarding the MAVF approach during the S-MAP proceeding, particularly with regard to how low probability, high consequence, such as wildfire, would be incorporated.[2] MGRA raised specific concerns that MAVF which is based on average values, might mis-represent risks with long tails and those described by power laws – specifically wildfire risks. In response, the Commission adopted MGRA's suggestion that the MAVF process be given a "test drive" to validate its performance for "extreme event risks".[3] Although this was done, only wire-down and not wildfire risk was chosen for the test drive. This was unfortunate, since wire-down analyses specifically reclassify wire-down events that start wildfire as wildfire events, thus limiting the maximum consequence.[4]

Proponents of the MAVF model suggested that any aberrations in the model results could be detected via a "sensitivity analysis", i.e. varying input assumptions and determining if these variations produced expected variations in the output.[5] Incorporation of sensitivity analysis, and allowing intervenors to request sensitivity analysis, was incorporated as Item No. 30 of the Settlement Agreement.[6] Thus the current analysis represents intervenors' first opportunity to test IOU implementation of the MAVF model as defined in the Settlement Agreement.

The results of the sensitivity analysis are surprising and disturbing. Comparing the PG&E and the TURN-01, 02 and 03 models reveals that overall and relative risk scores of various risk categories can vary by two orders of magnitude depending on assumptions. Furthermore, all of these underlying assumptions have good arguments for "reasonableness". The interaction of two major drivers accounts for these variations: first, the Commission's unintentional but implicit binding between safety and financial impacts, and second, PG&E's tuning its MAVF function and maximum consequence limits to favor avoidance of catastrophic events.

The Settlement Agreement set no binding between the safety attribute and the other attributes. However, the Commission intervened in D.18-12-014, setting a minimum weight of 40%

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[2] A.15-05-002-5; MUSSEY GRADE ROAD ALLIANCE COMMENTS ON THE SAFETY AND ENFORCEMENT DIVISION EVALUATION REPORT; April 11, 2016; pp. 8-11. (MGRA SED Report Comments)
[3] D.16-08-018; p. 114.
[4] MGRA was not able to participate in this phase of S-MAP.
[5] D.16-08-018; p. 126.
[6] D.18-12-014; Appendix A; p. A-17.

for the safety attribute.[7] The motivation for this change was "the Commission's commitment to making safety its highest priority."[8]

As we can see in the sensitivity analysis results, this decision has real consequences when related to risk rankings. Looking at model TURN-02 (similar to MGRA's original proposal), this model puts no cap on consequences and has a linear dependence on risk versus MAVF score. In a sense, this is the "baseline" model, relating what PG&E's calculated risks are without any further adjustments. Referring to page 3 of PG&E's October 2nd "RAMP Scenario Analysis Results" presentation, we see that while wildfire remains the largest risk (safety score 13,888), third party safety incidents are a close second (safety score 8,494). This is odd, in that MGRA is unaware of third party safety incidents causing massive loss of life, such as in the 2017 power line firestorm and the 2018 Camp fire. When financial and reliability risks are incorporated as well, the ratio of wildfire risk to third-party risk drops from 25:1 (PG&E scenario) to 4:1 (TURN-02 scenario).

The root cause of this effect is the requirement of a 40% safety attribute, and the fact that MAVF has a maximum scale for all attributes that, while it can be exceeded for event analysis, effectively binds the scale between attributes. PG&E's maximum values, for its own analysis and for TURN-02, are 100 fatalities for safety and $500 million for financial losses. PG&E also chooses to set the weighting of its safety attribute to 50%, rather the Commission-mandated minimum of 40%. These choices set an effective Value of Statistical Life (VSL) of $100 million, which is ten times larger than the value chosen by the Environmental Protection Agency and US Department of Transportation.[9] By taking the maximum number of fatalities to 1000 (as in TURN-01 and TURN-03), TURN effectively reduces the safety contribution by reducing VSL down to $10 million.

According to PG&E's own accounting,[10] the reason for the increase of third party and other risk scores with respect to wildfire was the large contribution of low-consequence events. Here it is important to highlight an important difference between wildfire and many other risk categories: wildfires are expensive. Specifically, wildfires present a larger proportion of financial risk to safety risk than other risk categories. If a third party is injured or killed, say by trimming a tree next to a

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[7] D.18-12-014; pp. 45-48.
[8] Id.
[9] RAMP; pp. 3-46 – 3-47.
[10] October 2, 2020 scenario analysis meeting between PG&E and stakeholders.

power line, financial impacts other than potential liability are minimal. In the case of wildfires, the loss of property is very substantial. Taking the 2017 and 2018 fires for example, the total potential cost claimed by PG&E in its bankruptcy proceeding was $30 billion. In total, there were approximately 140 fatalities for all fires. So approximately $200 million in losses was incurred for every death. The reason that wildfires destroy so much property as compared to human life is that most of the people threatened by a fire are able to evacuate from its path. The population of the California wine country and even Paradise is large compared to the number of injuries and deaths from the 2017 and 2018 fires. As horrible as the experience is,[11] the vast majority of people survive, and many more people lose their homes than lose their lives. So when the Commission asserts that it is important to give a minimum weight to “safety risk”, it is (unwittingly perhaps) taking the position that mitigation of other risk sources with a higher fatality to cost ratio should be given priority over wildfire mitigation. This bias is highly counterintuitive given the Commission’s emphasis on wildfire risk reduction over the past years.

PG&E chose a method that would compensate for this bias and increase the weight of catastrophic wildfire events. In their RAMP they explain: “We use a non-linear scaling function that has the effect of increasing the risk scores associated with catastrophic outcomes.”[12] The PG&E method consists of 1) a cap, and 2) a non-linear weighting function. The net result is that the relative difference between wildfire risk scores and other risk scores is much larger using the PG&E method. PG&E further explains that: “The non-linear scaling function supports our risk management philosophy which seeks to avoid low frequency, high consequence events that can have catastrophic consequences.”[13]

TURN-03 accomplishes the same result, but in a simpler and more defensible manner. It establishes a scale of 1000 deaths, rather than 100, as the canonical “maximum” (which can be exceeded but which sets the ration between financial and safety risks), and has a linear scaling. As can be seen on page 4 of the PG&E October 4th presentation, the ratios of wildfire to other risks are similar to those of the PG&E model. There are several advantages to using the TURN-03 model over the PG&E model:

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[11] We speak from experience. The Mussey Grade area was impacted by the 2003 Cedar fire and lost 2/3 of the homes in the neighborhood. There were, fortunately, no fatalities in the Mussey Grade area.
[12] RAMP; p. 1-12.
[13] Id.

- It sets a maximum scale that is a reasonable value.
- It sets a Value of Statistical Life that is more in line with those in common usage.
- It eliminates the artificiality of a non-linear model with arbitrary break points.

As to why it can be argued that 1,000 casualties is a potential consequence of a wildfire, one needs to look at the nature of wildfire losses, and power line wildfire losses in particular. It has been well-established that wildfire sizes follow a power law distribution.[14] If we assume that structure losses over time will generally correlate with overall fire size, then it should be expected that overall losses will be dominated by extreme events. For power law distributions with an exponent smaller than 2, the mean does not converge to a limit with sample size.[15] Malamud, et. al. determine an exponent of approximately 0.5, meaning that the mean will not converge. In other words, one would expect the average size of a wildfire (as well as average loss) to increase over time as more data is collected, and as more extreme events are included in the statistical sample. Hence, catastrophic losses larger than those that have been historically observed, while appearing "atypical" at the time of their occurrence, are expected for this kind of distribution. A caveat is that larger losses can be anticipated in the future up to the point where a maximum scale of loss is reached, i.e. we start running out of stuff to burn.

For power line fires, probability of ignition is coupled to the rapidity of fire spread both being strong functions of the severity of the causal weather event (specifically wind speed). Severe weather events can result in multiple near-simultaneous power line fire ignitions under conditions favoring rapid fire spread, and have an effectively lower power law exponent.[16] This effect substantially multiplies the probability of large-consequence fires. Unless measures are taken to

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[14] Malamud, B.D., Morein, G., Turcotte, D.L., 1998. Forest Fires: An Example of Self-Organized Critical Behavior. Science 281, 1840–1842. https://doi.org/10.1126/science.281.5384.1840
[15] Newman, M.E.J., 2005. Power laws, Pareto distributions and Zipf's law. Contemporary Physics 46, 323–351. https://doi.org/10.1080/00107510500052444
[16] Boer, M.M., Sadler, R.J., Bradstock, R.A., Gill, A.M., Grierson, P.F., 2008. Spatial scale invariance of southern Australian forest fires mirrors the scaling behaviour of fire-driving weather events. Landscape Ecol 23, 899–913. https://doi.org/10.1007/s10980-008-9260-5
Mitchell, J.W., 2009. Power lines and catastrophic wildland fire in southern California, in: Proceedings of the 11th International Conference on Fire and Materials, pp. 225–238.
Mitchell, J.W., 2013. Power line failures and catastrophic wildfires under extreme weather conditions. Engineering Failure Analysis, Special issue on ICEFA V- Part 1 35, 726–735.

substantially reduce wildfire risk, casualty levels exceeding those in 2017 and 2018 are not only possible they are inevitable over the course of time.

But why would 1,000 casualties be an appropriate choice? And why peg maximum loss to $500 million, when PG&E in two sequential years was responsible for wildfire losses over $10 billion? Given an understanding of the power law distribution, it should be assumed that even $10 billion in losses is not a reasonable maximum. If we were to choose instead $30 or $50 billion, then we would be back in the situation of TURN-02, with a very high VSL and suppressed relative wildfire risk.

It should be clear all of these choices are extremely arbitrary, and that the results (specifically the portion of risk attributed to wildfire versus other risk sources with lower cost per fatality) can be tuned to a specified result with a choice of scaling function or maximum scale values in conjunction with attribute weights. The Commission needs to understand that MAVF calculations are strongly dependent on parameter choices, and it should understand the implications of its decision to apply a minimum weighting to the "safety" attribute on the relative risk assigned to wildfire.

That being noted, of the MAVF models evaluated so far, MGRA believes that TURN-03 best balances transparency and defensibility. It satisfies PG&E's goal of avoiding catastrophic events while eliminating the tuned and arbitrary PG&E scaling function. It also adopts a reasonable maximum loss scale. As to the Value of Statistical Life and the relative weighting of wildfire with respect to other risks, these are issues that should be taken up in the S-MAP proceeding R.20-07-013, particularly in the discussion of ALARP framework (As Low As Reasonably Practicable).

2.2. Wind-Based Tranches

MGRA requested that PG&E prepare an alternative wind speed risk analysis based upon the local wind speed. MGRA's request to PG&E is attached as Appendix A. To summarize, MGRA requested the following analysis:

- Wind gust speed can be based on meteorological modeling or weather station data, though this should be done in a consistent way for the entire model run.

- If meteorological analysis uses continuous rather than gust wind speed, use a gust factor of 1.6.
- The tranches can be applied to the HFTD only.
- Each wind speed category should be separated into RFW / non-RFW tranches.
- Sub-driver (cause) information should be recorded for each incident. It is expected that certain ignition causes will show wind dependency (equipment failure, vegetation contact) and some will not (3rd party contractor, animals).
- Mitigation analyses should be done for each tranche.

The four wind speed categories that MGRA proposes are:

- Maximum wind gusts (MWG) within 3 miles < 25 mph
- 25 mph <= MWG < 40 mph
- 40 mph <= MWG < 55 mph
- MWG >= 55 mph

The goal of the MGRA analysis is to ascertain the extent to which wildfire is coupled to an external driver, specifically winds under fire weather conditions. These tranches can then be used to estimate the efficacy of wind-related mitigations, such as hardening or vegetation management.

In response, PG&E provided a spreadsheet containing all ignitions used in its analysis plus the seven major fires not included in the CPUC reportable fires on October 22, 2020. This is file "RAMP Scenario Analysis – WF – Wind Analysis_workbook.xls". The summary of PG&E's analysis was provided in the pdf file "RAMP Scenario Analysis - WF - Wind Analysis.pdf".

PG&E's results were surprising:

- *Out of total 2202 ignitions used (2015 2019), all large fires (greater than 300 acres) were in locations with the <25mph*
- *The data that PG&E used does not indicate higher conditional probability for large fire given an ignition in location with wind category of > 25 mph.*[17]

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[17] p. 4.

PG&E took the additional step of adding in seven of the major fires that were not included in its CPUC reportable events: the Butte, Atlas, Nuns, Sulphur, Redwood Valley, Cascade and Camp fires. Even these showed no fire starts under wind gust conditions greater than 25 mph, even though high wind conditions were reported in all official and news accounts of these fires.

The results of this analysis are dubious, and MGRA performed an analysis to cross-check them. To perform this analysis, weather station data publicly available from synopticdata.com was analyzed for each of the events. Weather stations are often at some distance from a fire ignition point. Recent publications have shown that extreme winds during fire weather events can be highly localized.[18] To account for potential variations in space and time variations of extreme winds, the MGRA analysis:

- Included major wildfire events provided by PG&E
- Added two selected large fires from the PG&E sample not included in the major fire category
- Expanded the time window around the ignition event to four hours
- Looked for peak wind at any weather station within 8 miles of the ignition
- Added the 2019 Kincade fire.

Results are shown in Table 1 below. They can be found in the "Examples" table of the file RAMP Scenario Analysis – WF – Wind Analysis_worbook-jwm1.xls, attached to this report.

Incident	Date	Location		Fire				Used in the Risk Input Sheet					
Incident	Date	Latitude	Longitude	Size (Acres)	Voltage (Volts)	Equipment /Facility Failure	Contact From Object	0_HFTD Zone	0_Tranche	1_Wind Categorization	Peak gust 8 mi	Station	Dist
PG&E - I1004	9/25/2016	38.80186	-122.817551	1000 - 4999	115000	Other	N.A.	Tier 3	HFTD - Transmission	<25mph	36	HWKC1	4.73
PG&E - I1502	10/20/2017	34.55317	-120.530293	100 - 299	12000	Crossarm	N.A.	Tier 2	HFTD - Distribution	<25mph	43	E2332	4.19
1. Butte	9/9/2015	38.32974	-120.70418	> 5000	12000	N.A.	Vegetation	Tier 2	HFTD - Distribution	<25mph	14	MTZC1	5.02
2. Cascade (Neu Wind Complex)	10/9/2017	39.32198	-121.4021	> 5000	12000	Conductor	N.A.	Tier 2	HFTD - Distribution	<25mph	29	BNGC1	4.15
3. Redwood Valley (Mendocino Lake Complex)	10/9/2017	39.24873	-123.16635	> 5000	12000	N.A.	Vegetation	Tier 2	HFTD - Distribution	<25mph	24	D9878	7.09
4. Nuns (Central LNU Complex)	10/9/2017	38.4041	-122.5209	> 5000	12000	N.A.	Vegetation	Tier 3	HFTD - Distribution	<25mph	42	E1582	7.05
5. Atlas (Southern LNU Complex)	10/9/2017	38.39206	-122.24367	> 5000	12000	N.A.	Vegetation	Tier 2	HFTD - Distribution	<25mph	36	F0187	3.03
6. Sulphur (Mendocino Lake Complex)	10/9/2017	39.01387	-122.64543	> 5000	12000	Pole	N.A.	non-HFTD	non-HFTD - Distribution	<25mph	40	KELC1	7.77
7. Camp Fire	11/8/2018	39.8134	-121.4347	> 5000	60000	Conductor	N.A.	Tier 2	HFTD - Transmission	<25mph	51	JBGC1	6.08
A. Kincade fire	10/23/2019	38.79246	-122.780053	> 5000 Acres	230000	Conductor	N.A.	Tier 3	HFTD - Transmission	?	80	PG305	2.18

Table 1 - Selected PG&E wildfire incidents including peak wind speed at nearest weather station in a four hour window.

[18] Coen, J.L., Schroeder, W., Conway, S., Tarnay, L., 2020. Computational modeling of extreme wildland fire events: A synthesis of scientific understanding with applications to forecasting, land management, and firefighter safety. Journal of Computational Science 45, 101152. https://doi.org/10.1016/j.jocs.2020.101152

The additional ignition events I1004 and I1502 were selected because they were in the High Fire Threat District and had available nearby weather station data. It should be emphasized that the MGRA analysis is a sampling of the data, and should not be considered a scientifically complete analysis. Regardless, the results strongly suggest that the PG&E POMMS model applied to this analysis is not accurately characterizing the wind conditions at the ignition points, and therefore that the conclusion reached by the PG&E analysis, specifically that there is no correlation between wind speed and wildfire consequence, is not valid. Of the ten samples selected, in only two do the peak local wind speeds match the predicted POMMS wind gust tier of less than 25 mph. Of the others, four are in the second tier (up to 40 mph wind gusts) and three are in the third tier (from 40 to 55 mph). The Kincade fire, which was not included by PG&E, had tremendous variation in wind gust speeds for nearby weather stations, with the highest peak wind gust of 80 mph being measured by a PG&E weather station only two miles from the ignition point.

PG&E does not take issue with MGRA's observation that peak wind gusts that are spatiotemporally related to ignitions can have large values.[19] Their POMMS model is based upon the WRF meteorological model and also incorporates weather station data.[20] It appears that the POMMS model is smoothing out local variations in a manner that eliminates high wind gusts. This effectively nullifies the proposed MGRA scenario by placing measurements into lower wind bins even in the cases where it is well known that extreme wind behavior was observed. Hence the current analysis cannot be accepted as complete. PG&E has agreed to continue to work with MGRA after the November 2nd deadline with a goal to produce a more adequate analysis.[21] MGRA for its part is working on an analysis of the entire PG&E ignition data set to present measured wind gust speeds for the entire sample, and hopes to provide these in advance of the SPD workshop. Even with the data presented there is a strong suggestion that wind speed is correlated with the consequence of large power line fires. A more complete analysis should show that wind speed affects probability of ignition as well. The hypothesis MGRA aims to test is whether wind-specific mitigations (hardening and EVM) will have an disproportionate impact in reducing catastrophic fire risk. MGRA suggests that SPD in its report request further data and analysis in this area be completed.

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[19] MGRA and PG&E scenario meeting; October 27, 2020.
[20] PG&E scenario meeting; October 28, 2020.
[21] Op. Cit.

Potential flaws in the POMMS model have impacts aside from mitigation planning. POMMS is used for as an input to PG&E's Outage Producing Winds (OPW) model.[22] The OPW model is used for setting the timing and geographic extent of PSPS events.[23] Hence if PG&E is underpredicting winds in fire hazard areas it will not be appropriately choosing what facilities to de-energize. Both the Camp and Kincade fires were ignited by facilities that PG&E chose not to de-energize during a PSPS event, and in both cases PG&E claimed that thresholds were below PSPS triggering threshold at the facilities where failures ultimately occurred.[24]

Another issue compromises the PG&E methodology for analyzing risk. The fact that PG&E uses ignitions as a metric means that data occurring during high wind fire weather will not be collected when lines are de-energized. MGRA raised this issue in the R.18-12-005 proceeding.[25] MGRA recommended the alternative metric of outages (while outage data during de-energization events would not exist, extreme winds can exist outside of fire danger periods) and of post-event damage reports.[26] PG&E began applying PSPS as a strategy in 2018 (to a lesser extent) and in a broader way in 2019. Hence, we would expect the ignition sample to be unbiased only for the 2015-2017 period.

SPD should therefore require that wildfire risk analysis not be based upon historical ignition data in areas and periods where infrastructure is subject to PSPS, since both ignition probability and

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[22] PACIFIC GAS AND ELECTRIC COMPANY 2020 WILDFIRE MITIGATION PLAN REPORT; February 28, 2020; pp. 5-52, 5-58, 5-63, 5-98, 5-106. (PG&E 2020 WMP)

[23] Id.; p. 5-293.

[24] PG&E Public Safety Power Shutoff Report to the CPUC; Events from: 11/6/2018 – 11/8/2018; pp. 2-3: "On Wednesday, November 7, 2018, PG&E refined the forecasted impact down to 63,000 customers and eight counties (Butte, Lake, Napa, Nevada, Placer, Plumas, Sierra and Yuba). Weather conditions stayed consistent, nearing but not reaching forecasted levels that would warrant temporarily turning off power for customer safety.
By around 13:00 on Thursday, November 8, winds were decreasing, and conditions were no longer forecast to approach PSPS criteria."
PG&E News Releases; Electric Incident Report Filed with CPUC in Response to Kincade Fire; October 24, 2019: "Those transmission lines were not deenergized because forecast weather conditions, particularly wind speeds, did not trigger the PSPS protocol. The wind speeds of concern for transmission lines are higher than those for distribution."
https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20191024_electric_incident_report_filed_with_cpuc_in_response_to_kincade_fire; Downloaded 10/29/2020.

[25] R.18-12-005; MUSSEY GRADE ROAD ALLIANCE COMMENTS ON THE DE-ENERGIZATION ORDER INSTITUTING RULEMAKING (OIR); February 8, 2019; pp. 9-10. Thomas Long also raised this issue during the October 28 PG&E scenario meeting. (MGRA Shutoff OIR Comments)

[26] Id. and R.18-12-005; MUSSEY GRADE ROAD ALLIANCE PHASE 1 DE-ENERGIZATION COMMENTS; March 25, 2019; p. 8.

wildfire consequence will be strongly suppressed in these samples. It should also be expected that certain values such as the outage to ignition ratio could possibly be biased by the application of PSPS and require supplemental analysis.

2.3. Power Shutoff Scenario Analysis

A number of intervenors requested additional analysis to quantify the safety impacts of PSPS, in other words dealing with PSPS as a risk in itself and not merely a mitigation. MGRA clarified its position on power shutoff in its informal Post-PHC Comments, which can be summarized as: "MGRA therefore favors the inclusion of PSPS risk in the scope of this proceeding in order to start the process of evaluating what information is available and what information still needs to be acquired in order to gauge PSPS risks and costs."[27]

MGRA has been involved in the shutoff issue since 2009 and was an early proponent of using cost/benefit methods to determine appropriate power shutoff thresholds.[28] In order to do this properly various types of customer harm would need to be quantified. One list provided by MGRA in R.18-12-005 was the following:

"

- Risk of loss of communication
    - Risk that fires are not reported
    - Risk that people are not informed regarding approaching fires
- Risk of improper resident mitigations causing house fires that turn into interface fires
    - Risk of candle ignited fires
    - Risk of improperly maintained generators causing fires
    - Risk of barbeque or fire-pit ignited fires
    - Risk that a house fire in a WUI area progresses to an interface fire
- Delays in evacuation putting residents at risk
    - Nighttime evacuation hampered by lack of home power
    - Failure of traffic signals causing traffic backups

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[27] A.20-06-012; MUSSEY GRADE ROAD ALLIANCE INFORMAL POST-PHC COMMENTS REGARDING POWER SHUTOFF; October 15, 2020; p. 3.
[28] D.09-09-030; p. 59.

- Danger to vulnerable residents
    - Medical baseline customers requiring power
    - Financial harm to marginal residents living paycheck to paycheck”[29]

It is MGRA’s belief that the Commission or WSD must drive the collection of this data, since utilities have a counter-incentive to adequately do this analysis. Specifically, utilities are unlikely to be held liable for harm directly or indirectly caused by power shutoff. Additionally, some of the analysis that would need to be performed to accurately quantify these items could be complex and therefore not amenable to completion within the time schedule of this proceeding.

MGRA was therefore skeptical that PG&E would provide a reasonable response to FEITA’s request for quantification of specific PSPS harms. PG&E’s response, in files “RAMP PSPS Scenario Analysis.pptx” and “EO-WF-4_PSPS Analysis Summary.xlsx” indeed fails to adequately respond to FEITA’s request, but provides important observations.

As to its shortcomings, PG&E’s “Safety Impact Modeling” (page 4) examines only bodily injury claims resulting from the 2019 event. Other analyses requested by FEITA are not performed. MGRA noted during the October 28th scenario status call that MGRA has in several proceedings provided data suggesting evidence that for whatever reason the number PG&E’s claims per affected customer is substantially less than that reported by SDG&E.[30] Additionally, PG&E’s analysis might miss bodily harm having secondary causes, such as a traffic accident that occurred because traffic lights were not working.[31]

On page 6 of its PSPS Scenario Analysis, PG&E calculates financial impacts of PSPS. It does so by applying the scaling ratio between Customer Minutes Interrupted (CMI) and an equivalent financial event. This ratio is determined by its MAVF function and the equivalent

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[29] R.18-12-005; MUSSEY GRADE ROAD ALLIANCE PHASE 2 TRACK 1 DE-ENERGIZATION PROPOSALS; September 16, 2019; p. 3.

[30] These were initially reported in MGRA’s comments on the 2019 power shutoff events. For a summary see: I.19-11-013; MUSSEY GRADE ROAD ALLIANCE COMMENTS ON THE ORDER INSTITUTING INVESTIGATION OF POWER SHUTOFF EVENTS SCOPING MEMO AND SED REPORT; October 16, 2020; pp. 14-15.

[31] In fact, there was a bodily injury case of exactly this type alleged in the list of claims that PG&E provided to CalAdvocates in the PG&E Order to Show Cause phase of R.18-12-005. See exhibit CalAdvocates-01, Supporting Attachments; p. PUBLIC-46.

maximum scales it has set for CMI and financial events. Using this ratio, PG&E estimates the total financial loss equivalent to the 2019 PSPS events was approximately $6 billion.

PG&E also presents its estimate of PSPS wildfire risk reduction for 2023-2026 compared to reliability impact on page 3 of its Analysis. In scaled units, it finds that wildfire risk reduction from PSPS is equivalent to 43k units, while reliability impacts are equivalent to 25k units, so that net risk reduction is 17k units. On page 5, PG&E explains that it expects PSPS impacts to be reduced by 30% over their 2019 values.

The information from 2019 and from PG&E's risk/RSE estimate on page 3 can be combined to reach the following conclusions:

- If future years are equivalent in risk to 2019, PG&E's outage costs per year would be reduced from $6 B to $4 B (30% impact reduction anticipated).
- Equivalent wildfire costs are 1.7 times larger than anticipated PSPS costs (using the ratio of 43k / 25k). This means that PG&E would anticipate losses of ~$7 B in a 2019-equivalent year from wildfire.

Some observations:

- These numbers are enormous. For comparison, even before settlement raw claims to SDG&E after the 2007 firestorm were less than $5 billion, and only $ 2 billion or so ended up being paid out.
- What PG&E presents is effectively a cost/benefit analysis for PSPS. Unfortunately, there is no evidence presented that it is a *correct* cost/benefit analysis. Nevertheless it provides a place to begin discussions. PG&E conclusion could be summarized: "You can have $4 billion in PSPS costs or $7 billion in annual wildfire costs during a year equivalent to 2019. Take your pick."
- The numerous factors leading to public harm from power shutoff listed by MGRA, FEITA, TURN, and many other intervenors over the years also need to be accounted for. However, as PG&E correctly pointed out in the October 28th scenario meeting, some of these factors may be incorporated into the equivalent financial loss of $4 B annually (2019 equivalent), and to listing them in addition would be double-counting. Furthermore, in order to contribute significantly to PSPS harm, their

effects would need to be noticeable against a $4 B annual cost. Some harm, such as generator or cooking fires leading to wildfire could potentially lead to catastrophic losses, but this needs to be quantified. The Commission should drive this effort.

- During the October 28th scenario meeting, PG&E showed that the total cost of PG&E's wildfire mitigation program is approximately $1.5 B annually, which is much smaller than the predicted losses from a 2019-equivalent year. The natural conclusion is that more should be spent on mitigation in order to bring the loss and PSPS costs down. Of course, it is not certain whether PG&E's approach to cost/benefit is valid, so it is essential that the Commission take an interest in understanding and validating PG&E's estimates.
- One final consideration is that in its Tariff Rule 14, PG&E rejects any liability incurred from power shutoffs. Recent history has demonstrated that PG&E can be held liable for wildfire losses. So in PG&E's PSPS cost/benefit analysis customers pays the costs and PG&E (and customers) get the benefit, so it should be unsurprising that PG&E has adopted power shutoff as its go-to strategy for wildfire prevention.

In conclusion, PG&E did not adequately respond to FEITA's request for quantification of its PSPS risk analysis. PG&E's analysis relating reliability to financial costs is interesting but lacks justification. It would be helpful if the SPD report were to highlight the gaps in the methodology for determining PSPS risk so that the Commission can lead the process of addressing those gaps in this and other proceedings.

3. OTHER SCENARIO ANALYSES

3.1. Granular Wildfire Risk Tranches - TURN

In addition to MGRA's wind-based wildfire risk analysis, another methodology for applying risk tranches was based on the risk score itself. Such an analysis was suggested by TURN. The results of this analysis are provided in the files titled "RAMP Scenario Analysis – WF Tranches.pdf" and "RAMP Scenario Analysis – WF Tranches_worbook.xlsx" (sic). The TURN scenario requested that PG&E risk data be divided into 13 tranches of approximately equivalent incremental risk, and analyzed with both the PG&E and TURN_03 MAVF models to obtain risk score and RSE. PG&E was able to provide a full analysis according to TURN's guidelines. PG&E based its risk assessment on a 2018 analysis of outage data. Ironically, MGRA requested a similar and simpler analysis from PG&E during the 2020 WMP cycle, requesting only a high and low risk tranche, and was told at that time that PG&E had no mechanism to perform such an analysis.[32] PG&E has demonstrated in its response to the TURN scenario that not only can PG&E perform a risk-based tranche analysis but that it can do so with high granularity.

The advantage of granular risk-based tranches is that they allow a more detailed view of risk reduction as a function of time. This is clearly illustrated on pages 6 and 7 of the wildfire tranche scenario report, which shows risk reduction being shifted from lower to higher tranches in the years after 2020.

A limitation to the TURN tranche proposal (or at least PG&E's approach to it) is that it is not particularly effective at identifying how individual mitigations related to risk sub-drivers might vary from tranche to tranche. This is because when ignitions are divided into sub-drivers and then further divided into tranches, the binning statistics are sparse and the variation from bin to bin is mostly due to statistical fluctuations. To circumvent this issue, PG&E attempted to use outage data instead of ignition data for its risk analysis because it constitutes a larger sample. Even for the outage-based analysis, however, tranche-to-tranche variation is still driven by statistical fluctuations and any real tranche-to-tranche variations will not be visible. (Report, p. 9 and workbook "SH" sheet) PG&E will need to perform another type of analysis (as yet undefined) and possibly include SME input to make any statement about the effectiveness of specific mitigations on each tranche or on a sub-driver within the tranche.

Another serious issue with the PG&E analysis affects not only the TURN risk-based tranche analysis and the MGRA wind-based tranche analysis, but also PG&E's baseline risk analysis. PG&E states that for its risk and consequence analysis, "the frequencies in the 2020 bow tie are

[32] MGRA 2020 WMP Comments; p. 45: IOUs "were asked to divide their circuits into two tranches: one representing the half of circuits having highest risk (according to their internal ranking methodology) and the other half having the lowest risk, and then to obtain an RSE for both groups. None of the utilities was willing or possibly able to perform this calculation. PG&E offered the following non-sequitur: "Currently, mitigation effectiveness in HFTD is the same across all circuits, even though some circuits may have higher/lower risk levels." Cites Appendix B of MGRA Comments:
MGRA DR4, Questions 2-6 and responses (SDG&E DR2) to SDG&E, SCE, and PG&E.
PG&E DR4, Question 5 response.

based on reportable ignitions data for 2015-2019, including data from seven additional fires that were not included in PG&E's annual report of ignitions to the CPUC because they were under investigation at the time the report was submitted."[33] Based on the analysis in the prior analysis of the MGRA wind scenario, this data set comprises two subsets:

- 2015-2017 data will have unbiased outage and ignition distributions
- 2018-2019 data will have both outage and ignition distributions that are biased in both temporal and geographic profiles by the application of PSPS events.

To summarize the previous analysis: ignition and outage data can't be collected when the power is shut off.[34] This implies that the data that remains is biased against particular characteristics that would lead an area to be placed under PSPS. For example, we expect that the 2018-2019 data:

- will be ***biased against*** geographic areas that are subject to high wind,
- will be ***biased against*** geographic areas that are subject to high Fire Potential Index,
- will have a ***suppressed*** ratio of catastrophic fires,
- will have a lower ignition to outage ratio.

MGRA has previously suggested the following potential remedies to this bias in areas affected by PSPS:[35]

- Analyze post-event PSPS damage reports to understand drivers and sub-drivers and include these as potential ignition events.
- Use outage data from high wind events outside of high FPI areas not subject to PSPS and include these as potential ignition events.
- Use SME expertise and unbiased data to estimate ignition probabilities for PSPS damage.

While it is late for SPD to suggest a remedy for this fairly serious problem in this RAMP cycle, the issue does not affect the whole data set. Furthermore, PSPS in 2018 was fairly limited in

[33] PG&E RAMP, p. 10-9.
[34] The classic joke about this situation involves the inebriated person who drops their keys into the bushes by the front door and then looks for them under the street lamp because that is where the light is.
[35] MGRA Shutoff OIR Comments; pp. 9-10.

scope. However, SPD should emphasize the importance of post-PSPS damage report collection as a fundamental input for future risk analysis.

3.2. Rapid Earth Fault Current Limiter (REFCL) Scenario Analysis

SPD recommended a scenario analysis for the Rapid Earth Fault Current Limiter (REFCL) technology, which is currently in use in Australia and is being investigated by all major California IOUs. PG&E's implementation is ahead of the other IOUs at this point, and according to its "SPD Scenario Analysis – REFCL" report of October 19, 2020, is planning to have 160 miles of circuit protected by a REFCL system by 2021.

While this is currently an R&D project, should it proved successful it would have the extraordinarily high RSE of 126. REFCL does not protect against all ignition sources. Any conductor-to-conductor contact – through line slap, animal contact, or vegetation across conductors, would still be potential ignition sources. However, according to PG&E's project lead the combination of covered conductor and REFCL would prevent ignition from all common ignition sources. This could be considered, then, a complete solution to the utility wildfire problem.

4. CONCLUSION

Taken in combination, the supplemental analyses performed by PG&E at the request of parties lead to some surprising, worrisome, and hopeful observations:

- MAVF results are very sensitive to assumptions made by the utility, and the relationship between these assumptions and results should be taken up in the S-MAP proceeding.
- Evidence presented in the PG&E wind analysis imply that the PG&E POMMS model, which is used in setting the timeframe and geographic area for PSPS, may not be predictive of local peak wind speeds.
- PG&E's modeling assumes that PSPS events have extremely large negative financial impacts on customers, but that absence of PSPS would lead to even larger wildfire losses.

- PG&E risk modeling based on ignition history data will show a bias against areas and conditions that are subject to PSPS.
- Should the REFCL technology prove effective, the Commission should investigate a crash program to deploy covered conductor and REFCL. If further analysis of PSPS impacts confirms PG&E's assertion that both wildfire costs and PSPS costs are unreasonably large, a program to systematically and rapidly eliminate wildfire risk in the HFTD should be considered, with legislative assistance to fund the program if required.

Respectfully submitted this 2nd day of November, 2020,

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Appendix A – MGRA Wind Speed Tranche Request

MGRA Proposal for PG&E RAMP Sensitivity Analysis
Draft 9/8/2020

1. INTRODUCTION

As per Row 30 of the Settlement Agreement, intervenors may request a sensitivity analysis through the discovery process. In MGRA's protest, we raised a number of issues specifically related to PG&E's wildfire analysis.

In its September 2, 2020 presentation, PG&E proposes that sensitivity and scenario analysis be performed in an organized fashion in three separate areas. While intervenors do not agree with PG&E on limiting the analysis in this way, MGRA understands that there will be limits on the type and scope of analysis that can be performed in order for SPD to complete its report as per a modified schedule. MGRA suggests in this proposal two areas needing further study.

2. WIND AS A CROSS-CUTTING RISK FACTOR

In its protest, MGRA suggested that extreme winds should be handled as a cross-cutting risk factor, in that they affect multiple risk domains (specifically wildfire and wires down), drive the frequency of risk events (by increasing the probability of equipment failures and vegetation contact), and also the consequences of risk events (since wildfires expand explosively when high winds are coupled with low humidity and dry vegetation).

MGRA suggested an alternative version of PG&E's risk bow-tie, illustrated below:

FIGURE 10-2
RISK BOW TIE – HFTD ONLY

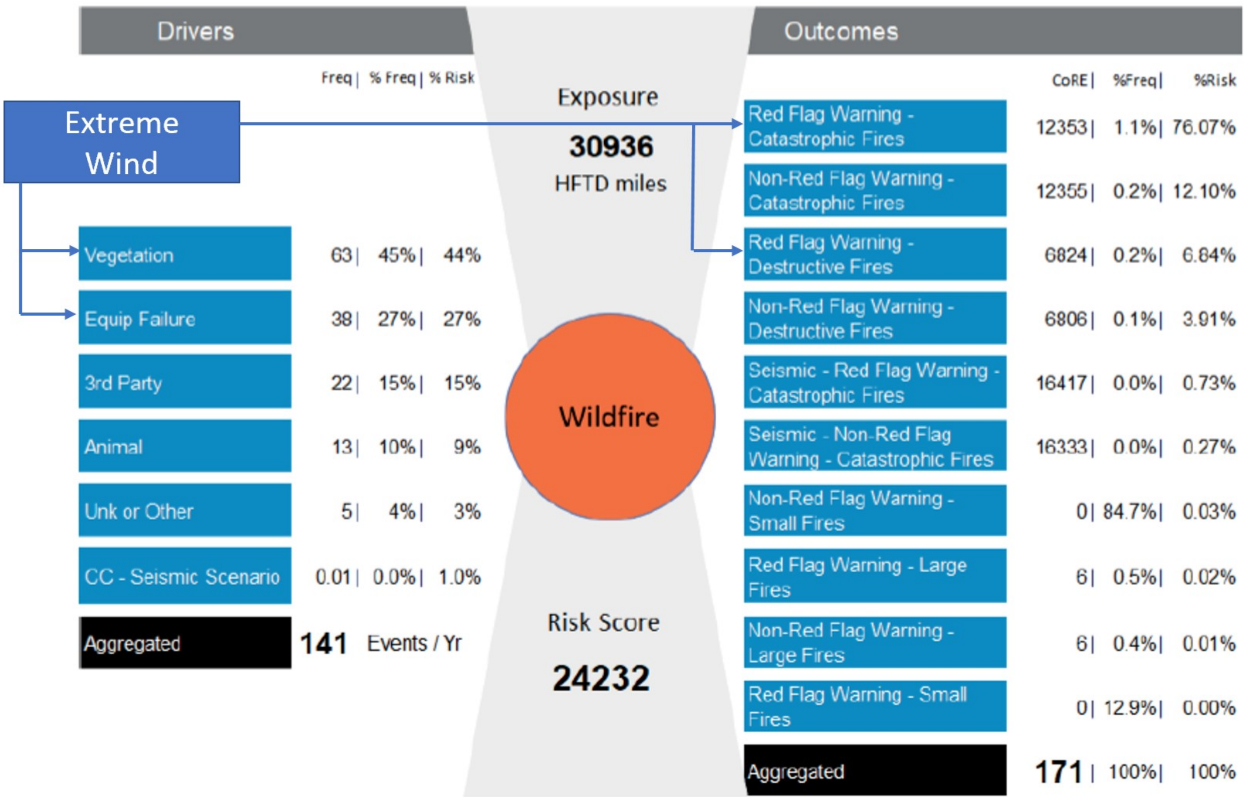

Figure 1 - Effect of extreme wind on PG&E's risk bow tie diagram for wildfire. Extreme wind affects frequency, causing vegetation contact and equipment failure, and during Red Flag Warnings can lead to accelerated fire spread and losses**.**

In its response to TURN's suggestion from February of this year suggesting that wind is its own risk event, PG&E responded that using Red Flag Warning would provide a similar ability to track extreme fire risk. As noted in MGRA's protest, this is not adequate:

"First, Red Flag Warnings are Boolean designations: either a Red Flag Warning is called or it is not. Wind conditions, on the other hand, impact outage frequency as a function of wind speed. There is no designation where winds become "extreme". Second, Red Flag Warnings have several components aside from wind, including temperature and humidity, and these have a small effect on outage probability, thus diluting the contribution of wind. Finally, extreme winds can cause outages even in the absence of fire danger, but still contribute to electrical asset failure. For example, a windstorm in November/December 2011 resulted in widespread damage to SCE's distribution network, damaging over 1,000 conductors and 248 wood poles, and affecting over 400,000 customers.[36]"

PG&E seems to prevent the following model for estimating risks:

Risk events are defined as ignitions as per CPUC reportable event definitions. This is used by PG&E to estimate a frequency/probability for risk events.

Consequences are then estimated based on loss figures from Cal Fire data running from 2015-2019, which gives details of fires 300 acres or more. PG&E claims that 95% or its ignitions are smaller than this size, and it determines the size distribution from 2015-2019 data, fit to a lognormal distribution.

There are a number of problems with this approach, including but not limited to:

- Destructive fires are not distributed randomly in time, but are strongly clustered with specific weather events.
- Failure probability for both equipment and vegetation increases as a strong function of wind speed.
- Use of lognormal distribution to fit fire sizes is not correct, and will be expected to potentially underestimate the tails. Wildfire sizes are distributed according to a power law distribution. The outage/wind speed function is not well-determined but is extremely steep (a factor of 10 for every 15-20 mph increase). It may be the leading edge of a Weibull distribution. Together, these effects lead to the expectation that catastrophic fires may occur with greater frequency than would be expected from lognormal.
- There are certain characteristics of catastrophic powerline fires that can be assumed based on prior knowledge, and renders a number of tranches not particularly useful:
    - They will occur in the High Fire Threat District
    - Causes will be related to vegetation, equipment failure, or line slap. Other causes will be statistically suppressed.
    - They will occur during Red Flag Warnings.

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[36] California Public Utilities Commission; Consumer Protection and Safety Division; Investigation of Southern California Edison Company's Outages of November 30 and December 1, 2011; Final Report; January 11, 2013.

Ideally, a risk analysis would start with outage data rather than ignition data. This approach would allow the same analytical method to be used for both wildfire risk and wire-down risk. It would also specifically call out wind as a risk driver. In fact, the most important input distribution would be the frequency and magnitude of extreme wind storms.

To handle the wind ignition modeling, an approach similar to the following could be used:

- Wind events are drawn from a distribution. Currently we don't have a good model for this distribution but historical data could be used with the caveat that we are not sure it is a good predictor of future wind events.
- Wind event is modelled over the PG&E service territory and local peak winds are determined.
- Based on PG&E's Outage Producing Wind model and asset catalogue, outage probabilities per circuit are predicted, and using a Monte Carlo method a sample of outages are created for the event. A wires-down risk model could stop at this point and calculate consequences.
- Using fire index or red flag warning data, the potential for ignition for each of the outages could be determined. Another Monte Carlo would model number of actual ignitions. PSPS mitigation modelling could be applied at this point.
- Based on the ignition location and weather conditions, fire spread modelling could determine size of the fire.
- Comparison with fires of equivalent size from an extended Cal Fire data set (more than five years) should allow estimation of safety and financial consequences.

While this would be an ideal approach, it is quite far from PG&E's actual approach to calculating wildfire risks and it is unlikely that PG&E could make substantial progress implementing such an analysis in time for SPD's review.

MGRA therefore suggests an alternative approach that is intended to demonstrate the sensitivity of PG&E's wildfire risk to extreme weather events:

- Identify eight additional tranches based on maximum wind gust speed within 3 miles of each ignition point and local red flag warning status.

- Wind gust speed can be based on meteorological modeling or weather station data, though this should be done in a consistent way for the entire model run.
- If meteorological analysis uses continuous rather than gust wind speed, use a gust factor of 1.6.
- The tranches can be applied to the HFTD only.
- Each wind speed category should be separated into RFW / non-RFW tranches.
- Sub-driver (cause) information should be recorded for each incident. It is expected that certain ignition causes will show wind dependency (equipment failure, vegetation contact) and some will not (3rd party contractor, animals).
- Mitigation analyses should be done for each tranche.

The four wind speed categories that MGRA proposes are:

- Maximum wind gusts (MWG) within 3 miles < 25 mph
- 25 mph <= MWG < 40 mph
- 40 mph <= MWG < 55 mph
- MWG >= 55 mph

By this analysis MGRA suggests that PG&E will show that catastrophic fires are much more likely to occur due to ignitions under high wind and high fire danger conditions. This should help in the selection of mitigations that reduce wildfire risks under conditions most likely to foster catastrophic fires.

3. MAVF, SCALING AND VALUE OF STATISTICAL LIFE

As MGRA noted in its protest PG&E acknowledges that the primary risk driver from wildfire will come in the form of catastrophic events:

"PG&E's risk modeling, analysis and mitigation strategy is focused on reducing the potential for catastrophic risk events and the consequences of those events. In terms of risk modeling, this strategy entails paying special attention to tail risk—the low frequency, high consequence events. We achieve this in the 2020 RAMP by using a non-linear scaling function which gives a greater weight in the risk model to low frequency, high consequence events than to high frequency, low consequence events.

PG&E is risk-averse in the sense that term is used in economics. Given a choice between two mitigations that theoretically reduce the same expected amount of loss, one of which is targeted at catastrophic (low frequency, high consequence) risk events and another that is targeted at routine (high frequency, low consequence) risk events, our preference is to select the mitigation that targets the catastrophic events because of the uncertainty of their frequency and consequence."[37]

PG&E's scaling function truncates at a "maximum value". PG&E defines a maximum value of safety, reliability, and financial risk, as per the Settlement Agreement which states that: "For an Attribute with a numerical natural unit, such as dollars, the smallest observable value of the Attribute is the low end of the range and the largest observable value is the high end of the range."[38] The Settlement Agreement instructs utilities to convert the range of natural units to a 0 to 100 scale.[39] PG&E therefore truncates maximum fatalities at 100, corresponding approximately to the size of the Camp fire.[40] This truncation effectively invalidates its own stated goal risk aversion.

MGRA suggests the following sensitivity analysis to determine the effect that PG&E's choice of maximum scale has on its risk scores and RSEs:

Re-run the analysis with maximum safety impact equivalent to 500 casualties, and maximum financial loss of $40 billion.

These numbers are chosen to be substantially larger than historical losses. One property of power law distributions, for which wildfire is a classic example, is that future maximum loss will always exceed historical losses. We would expect the numbers suggested above to be exceeded over the course of time, but they provide an illustrative example of the effects of the choice of maximum risk levels on the risk scores and RSEs.

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[37] RAMP; p. 3-2.
[38] D.18-12-014; Appendix A; p. A-3. (Settlement Agreement)
[39] Id; and p. A-5.
[40] RAMP; pp. 3-46 – 3-47.

APPENDIX 4

Informal Comments of The Utility Reform Network (TURN) to the Safety Policy Division on PG&E's RAMP Report and Scenario Results

The Utility Reform Network (TURN) appreciates this opportunity to provide the Safety Policy Division (SPD) with our comments on PGE's RAMP Report and Scenario Results , which we hope will aid SPD with its official report on PG&E's RAMP filing. These comments are divided into two parts. In Part I, we discuss the most significant problems we have identified with PG&E's Report to date, recognizing that TURN's analysis is continuing and still not complete. In Part II, we discuss alternative scenarios that TURN requested PG&E to perform, including TURN's interpretation to date of the results of those scenarios.[1]

PART I

The Most Significant Problems with PG&E's RAMP Analysis

1. Insufficient Granularity of Tranches

A pervasive and serious problem with PG&E's RAMP Report is the lack of sufficient granularity in the tranches PG&E used for the analysis. To date, TURN has emphasized this problem with PG&E's analysis of the Wildfire risk, but it applies to many other risks in PG&E's report.

Row 14 of the S-MAP settlement requires each element (i.e., asset or system) in an identified tranche to "have homogeneous risk profiles (i.e., considered to have the same LoRE and CoRE)." In other words, to comply with the Settlement, all of the assets in each tranche should be grouped so that there are no significant differences in either the LoRE or the CoRE of those assets. If there is a meaningful difference, the asset group needs to be broken out into more granular tranches.

Sufficiently granular tranches are necessary to achieve the goal of providing accurate information for GRC decision-making about the cost-effectiveness of proposed mitigations. When assets with different LoRE and CoRE values are lumped together, the resulting average RSE values will mask differences in individual asset RSEs. This matters because a key objective of this quantitative analysis is to identify mitigations that will provide the greatest risk-reduction value for PG&E's customers, employees, and the public at large. Using average RSE values that do not account for individual asset differences prevents the Commission from having a record that allows it to make fine-tuned decisions about which mitigations to approve and in what scope, given affordability and other constraints.

[1] For SPD's ease of reference, in these informal comments, TURN has underlined its recommendations for conclusions in SPD's report.

An example will illustrate the concern. The table below compares two sets of RSE values for the same assets: one based on a less granular tranche analysis and the other on a more granular analysis.

Table 1: Granular Tranches Give More Accurate and Useful RSE Values

	M1	**M2**		**M1**	**M2**
Tranche 1	10.0	5.0	**Tranche 1.1**	25.0	12.0
			Tranche 1.2	4.0	7.0
			Tranche 1.3	1.0	0.5
Tranche 2	1.0	3.0	**Tranche 2.1**	4.0	8.0
			Tranche 2.2	0.1	0.2

In the columns on the left, only two tranches are used to determine the RSEs for two mitigations, M1 and M2. In the columns on the right, Tranche 1 is broken down into 3 tranches and Tranche 2 is subdivided into two tranches. If the Commission were inclined to approve mitigations with an RSE of 5.0 or greater, the analysis on the left would argue for approving both mitigations for all of Tranche 1 and rejecting both mitigations for all of Tranche 2.

However, with the more granular information on the right side, the Commission would see that, for M1, the RSEs exceed the 5.0 benchmark *only for part of Tranche 1*, namely Tranche 1.1. In addition, the Commission would learn that the M2 mitigation exceeds the RSE benchmark for part of Tranche 1 (Tranche 1.2) and part of Tranche 2 (Tranche 2.1). In sum, contrary to what was indicated by the less granular analysis, cost-effectiveness would be maximized by performing M1 for only a subset of Tranche 1 and by performing M2 for a subset of Tranches 1 and 2.

1.1 Wildfire Risk

The problem of insufficient granularity of PG&E's tranches for the Wildfire Risk has already been well discussed in the workshops and other meetings. PG&E's distribution and transmission tranches are clearly not in compliance with the Settlement. It is simply not credible that there are no meaningful differences in either the LoRE or the CoRE for the very large number of miles in each of the following tranches:

- HFTD Distribution (To Be Hardened) – 6,929 circuit miles
- HFTD Distribution (Remainder) – 18,310 circuit miles

- HFTD Transmission -- 5,525 circuit miles
- Non-HFTD Distribution – 55,300 circuit miles
- Non-HFTD Transmission – 12,600 circuit miles

TURN encourages SPD to call out these massive, non-homogenous tranches as an obvious failure to comply with the Settlement and as a disservice to the Commission's efforts to obtain useful cost-effectiveness data for GRC decision-making.

Although none of these excessively large tranches are defensible, TURN is most concerned about the HFTD tranches, since this is the part of the system with the most risk and where we expect wildfire mitigations to be focused. However, to the extent mitigations are proposed for any non-HFTD miles, these tranches also need to be broken down into more homogenous tranches.

PG&E's own data from its 2019 GRC make clear that the Distribution - To be Hardened" and "Distribution - Remainder" tranches are not sufficiently granular. Based on data from PG&E's 2019 GRC filing summarized in Table 2 below (reflecting TURN's requested tranche scenario),[2] 60% of the risk for the Distribution- To Be Hardened tranche is found in approximately 2,300 (see Rows 2-7), or about 30% of the 6,900 miles in that tranche. In addition, the Risk Unit per Mile column shows risk is generally higher in the more granular tranches towards the top of the table, falling off considerably beginning with Row 8.[3]

[2] This scenario is discussed in Part II, Section 1.2 of these comments.

[3] As discussed in Part II, Section 1.2, TURN is not contending that the rows in Table 2 are sufficiently granular to satisfy the requirements of the Settlement. Each row likely masks major differences in LoRE or CoRE that warrant more granular tranches.

Table 2: Risk Allocation by Sub-Tranche of "Distribution – To be Hardened" and "Remainder" Circuits

Distribution - To be Hardened Tranche	Incremental Circuit Miles	Cumulative Circuit Miles	LoRE (Events/Year)	Wtd Average CoRE	Tranche Risk	Percent of Total Risk	Risk Units per Mile
2	325	325	2.3	1022.4	2,319	10%	7.14
3	434	759	2.5	956.8	2,427	10%	5.59
4	397	1,156	3.0	812.9	2,415	10%	6.09
5	395	1,551	2.6	911.3	2,355	10%	5.96
6	355	1,906	2.9	837.9	2,436	10%	6.86
7	392	2,298	3.2	741.7	2,376	10%	6.06
8	625	2,922	3.6	676.5	2,403	10%	3.85
9	616	3,538	3.8	625.7	2,380	10%	3.86
10	396	3,933	2.5	491.4	1,211	5%	3.06
11	463	4,396	2.8	431.5	1,196	5%	2.58
12	1,161	5,557	3.2	374.9	1,201	5%	1.03
13	20,038	25,595	37.7	31.7	1,197	5%	0.06
TOTALS	25,595		70.0		23,915	100.0%	0.93

Source: TURN analysis of PG&E "Dx Proritization Analysis"

Even the level of granularity reflected in Table 2 is not ideal because, based on PG&E's data, the LoRE and CoRE values for each circuit within each of these tranches differ. For example, PG&E undoubtedly knows that particular locations within HFTDs are more susceptible to fire weather conditions or high fuel content than other HFTD areas

PG&E should also consider designing tranches based on the specific characteristics of individual equipment types that tend to increase the likelihood of occurrence of wildfires. For example, a distribution circuit includes poles, wires, transformers, reclosers, and other identifiable assets. Each of these types of equipment has different failure rates and different likelihoods of causing a wildfire. These differences could be used to create separate equipment-specific tranches. In Chapter 11 of its RAMP filing, PG&E discusses failures of DOH assets by equipment type and has created tranches based on reliability performance. It is reasonable to assume that some of these failures can lead to wildfires.

The bottom line is that PG&E's Report does not even approach the level of granularity that the Settlement mandates and that the Commission needs in order to make informed judgments in the GRC about which mitigations should be approved and in which scope. As discussed further in Part II, Section 1 below, <u>PG&E should be advised to work with the parties to develop a much more granular set of tranches for the Wildfire risk to determine RSEs for PG&E's upcoming GRC filing</u>**.**

1.2 Gas Transmission and Distribution Pipeline Risks

In the RAMP, PG&E identified four tranches for the 6,682 miles of transmission pipe on its system.[4] Of these four tranches, PG&E identified two tranches (Tranches 1 and 2) with a total of 5,038 miles of transmission pipe that account for 81% of transmission pipeline risk, and a third tranche of 816 miles that accounts for 19% of transmission pipeline risk.[5] These tranches contain pipe of different vintage, different diameter, and different manufacturing techniques, along with pipe operating at different operating pressures. These differences, and others, are required to be tracked under pipeline Integrity Management programs, precisely because they affect pipeline failure rates.

In the S-MAP Test Drives, PG&E provided data at the individual pipe segment level that included many descriptive pipe characteristics. But in the RAMP report, PG&E claims that "it was difficult to determine which attributes were best indicator of overall asset health."[6] PG&E has never explained the basis for this claim, nor described the analysis the company undertook to make its determination that no attributes were indicators of asset health.

TURN believes the transmission pipe tranches are far too aggregated. For example, TURN believes there are likely to be differences in CoRE values associated with pipe having different diameters. All else equal, a rupture and ignition event for a pipe of 42 inches diameter is likely to have far larger consequences than the same event on a pipe with a 24-inch diameter. Moreover, with respect to the LoRE, in the S-MAP test drive, PG&E's SMEs identified pipe attributes that affected failure rates. Furthermore, for distribution pipe, PG&E has created separate tranches for different types of pipe. Given that fact, it seems unlikely that different types of transmission pipe would not have different failure rates. In any event, Tranches 1 and 2 are far too large and mask important differences in LoRE and CoRE that need to be assessed in order to enable the Commission to have accurate information about the cost-effectiveness of mitigations. PG&E uses such information in deciding which pipe on its system to prioritize, and it should be used to develop more accurate RSEs for the GRC.

TURN similarly believes the PG&E's distribution pipe tranches are too aggregated, for many of the same reasons. Different sizes of distribution pipe, different pipe manufacturing methods, and so forth, will lead to different LoRE and CoRE values within each of PG&E's tranches, thus limiting the accuracy of the resulting RSE calculations.

It is also the case that PG&E does not use asset condition to delineate tranches, even though asset condition is likely an important determinant of LoRE. It is reasonable to ask why PG&E is not

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4 *Id*. p. 7-9, Table 7-2.

5 *Id*. p 7-7 and p. 7-9, Table 2.

6 *Id*. at 7-8.

using this important information when PG&E specifies the tranches. If PG&E does not know the condition of the assets at present, it is reasonable to ask what PG&E is doing to determine asset condition, so that the tranches can be based on condition-dependent LoRE.

PG&E should be advised to significantly improve the granularity of its gas transmission and distribution tranches in the updated analysis for the GRC**.**

2. Failure to Assess PG&E's Operational Failures as a Driver of Wildfire Risk

PG&E's RAMP Report ignores the most obvious driver of catastrophic wildfires at PG&E – PG&E's failure to meet operating standards and to perform its work properly. In 2017, Cal FIRE determined that 11 of the 17 North Bay fires resulted from PG&E violations of tree trimming requirements. With respect to the 2018 Camp Fire, PG&E plead guilty to the crime of involuntary manslaughter – which means acting with a reckless disregard for public safety. And, according to media reports, Cal FIRE has found that reckless conduct by PG&E is responsible for the 2019 Kincade Fire.[7] Moreover, the Federal Court Monitor, appointed as a condition of the probation arising out of PG&E's San Bruno convictions, has issued two detailed reports – one in 2019 and another just recently in October 2020 -- finding serious deficiencies in how PG&E has carried out its vegetation management work and its facility inspections.[8] Absent these operational failures, many of the most serious wildfires of the past three years would not have occurred.

As the *San Francisco Chronicle* said in a recent editorial titled "PG&E Still Can't Seem to Do Its Job," PG&E's "Plan A should be maintaining its power lines and other infrastructure while clearing nearby vegetation" but "PG&E is still struggling to tend to this basic task."[9]

Nevertheless, despite this history, PG&E's Wildfire Risk analysis refuses to acknowledge its operational failures as a key driver of catastrophic wildfires. Instead, PG&E wants the Commission to accept its fantasy view of the world in which these operational failures have nothing to do with the wildfires PG&E has caused. By excluding the driver of operational failures, PG&E's risk mitigation analysis ignores what is likely the most important mitigation of all – the Plan A of simply doing its work properly. Spending billions of dollars on vegetation management and facility inspections is not cost-effective if the work is not performed correctly.

[7] CalFIRE's Kincade Fire report is not public because it has been referred to Sonoma County prosecutors for criminal prosecution of PG&E.

[8] October 16, 2020 and July 26, 2019 Letters from Mark Filip, Federal Monitor, to Judge William H. Alsup.

[9] *San Francisco Chronicle*, "Editorial: PG&E Still Can't Seem to Do Its Job," October 27, 2020, found at: https://www.sfchronicle.com/opinion/editorials/article/Editorial-PG-E-still-can-t-seem-to-do-its-job-15676777.php

When operational failure is included as a driver, PG&E is forced to focus leadership attention on relatively low-cost measures (such as improved Quality Assurance and Quality Control) that would provide a major risk reduction benefit.

By excluding this key driver of risk, PG&E is inviting us to accept the myth that its operational failures are not a source of risk and, thus, do not need attention from its leaders and its regulators -- that expensive mitigation programs should be the only focus. Although significant spending on wildfire mitigation programs will be necessary, a true and correct portrait of PG&E's Wildfire Risk requires that the considerable risk resulting from PG&E's operational failures be recognized and that the risk reduction benefits from fixing those problems be quantified. Absent inclusion of operational failures as a driver, the risk analysis is incomplete and insufficient, to the detriment of ratepayers who will be required to pay billions for wildfire mitigation programs.

TURN repeatedly raised this issue with PG&E in the workshops and other party meetings in this case - to no avail. It is clear that PG&E leadership[10] has no interest in honestly acknowledging the major contribution that operational failures make to PG&E's wildfire risk. This stance is consistent with PG&E's posture in the recent bankruptcy case before the CPUC. In the decision in that case, the Commission characterized PG&E's recent safety performance as ranging "from dismal to abysmal" and found as "a cause for concern" PG&E's reluctance "to take ownership of its safety history and acknowledge its failings."[11]

It should therefore be clear that PG&E will not fix this omission and provide an accurate Wildfire Risk analysis unless it is pressured to do so by the Commission. <u>An important start would be for SPD to identify the omission of operational failures as a risk driver as a major deficiency in PG&E's Report that should be corrected in the updated GRC analysis</u>**.** No one likes confrontation, and TURN takes no joy in highlighting this problem, but wildfires pose an urgent and catastrophic threat. This is not the time to allow discomfort with controversy to get in the way of a truthful and complete analysis of PG&E's wildfire risk and the necessary mitigations.

3. Problems with PG&E's Multi-Attribute Value Function (MAVF)

The MAVF is the foundation upon which the consequences of risk events are measured. Unreasonable judgments in framing the MAVF can have a significant impact on the calculations of pre- and post-mitigation risk scores and therefore on the RSE calculations. PG&E made four unreasonable choices in fashioning the MAVF it used for its RAMP analysis.

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[10] TURN wishes to be clear that it is not faulting the PG&E RAMP analysts who have been the face of this case for PG&E. The problem clearly lies with PG&E's leadership refusing to take ownership of the company's operational problems, which all but guarantees the perpetuation of those problems.

[11] D.20-05-053, p. 17.

3.1 Nonlinear Scaling Functions for Safety and Financial Attributes

PG&E's MAVF has nonlinear scaling functions for both safety and financial consequences. These scaling functions should be replaced by linear scaling functions.

PG&E's nonlinear scaling functions lead to preferences that defy common sense. Generally, PG&E's nonlinear scaling functions decrease the value of mitigating the risk of less consequential but more frequently occurring events, compared with the value of mitigating the risk of more consequential but less frequently occurring events. Although PG&E has stated it wishes to focus on events with larger damages, the non-linear scaling functions mean that PG&E values reduction in the level of an attribute (e.g., equivalent fatalities) associated with a catastrophic event by more that ten times an equivalent reduction in a smaller-scale event. This is not reasonable because the repeated occurrence of the more frequently occurring event is expected to inflict more damage, measured in dollars or fatalities, over a fixed time period, say a year, than the infrequent occurrence of the more consequential event, such as a wildfire.

For example, using PG&E's nonlinear scaling function for the Safety attribute, the scaled value of reducing the expected number of equivalent fatalities from 11 to 10 is 1.06 scaled units. The scaled value of reducing the expected number of equivalent fatalities from 1 to 0 is 0.10 scaled units, less than one-tenth the former amount. As such, if an event that results in 11 fatalities is expected to occur once per year but the event that results in 1 fatality is expected to occur 10 times per year, then the mitigation that reduces the expected number of deaths from 11 to 10 is preferred to the mitigation that reduces the expected number of deaths from 10 to 0 for 10 separate events.

In other words, PG&E would prefer to avoid one death associated with an event that would otherwise be expected to cause 11 deaths, compared with avoiding 10 deaths associated with avoiding 10 separate events, each expected to lead to one death. This is not a rational tradeoff and should not be accepted by the Commission.

The non-linear scaling function for the Financial attribute is also counterintuitive and inconsistent. Based on this scaling function, PG&E would prefer to reduce the expected financial consequences of an event by $100 million, from $600 million to $500 million, compared with avoiding 10 separate events, each having a $100 million loss. In other words, PG&E would prefer to accept a total of $<u>1 billion</u> in losses from 10 separate events in order to avoid a single <u>$100 million</u> loss from a larger event. Again, this is not rational and should not be accepted by the Commission.

Therefore, <u>the nonlinear scaling functions for safety and financial consequences should be replaced by linear scaling functions</u>.

3.2. Capped Scaling Functions

The PG&E scaling functions are capped at the upper limit of the attribute measured in natural units. This capping assigns the scaled value of 100 to any outcome that is greater than or equal to the upper limit of the attribute measured in natural units. For example, a financial loss of $100 billion is valued the same as a financial loss of $5 billion, or a catastrophe that results in 500 deaths is valued the same as a catastrophe that results in 100 deaths. This makes no sense.

The caps should be removed. Nothing in the Settlement requires capped scaling functions. Instead, extending the scaling functions beyond their upper limits in natural units is simple and reasonable.

3.3. Inflated Statistical Value of Life (SVL)

The statistical value of life (SVL) is a measurement of the value of mitigating the risk of death. Importantly, SVL is not a valuation of any individual life. Instead, it is a measure of how much society is willing to pay for marginal reductions in the risk of dying across a broad population. The SVL is implied in the MAVF and is found by comparing the ranges (in natural units) and the weights of the Safety and Financial Consequences attributes. For PG&E's MAVF, the implied SVL is $100 million. This is because the weight of the Safety attribute is 0.50, the weight of the Financial Consequences attribute is 0.25, and the ranges are 100 equivalent fatalities (EFs) and $5 billion, respectively. Hence, 100 EFs have the same weight as $10 billion, which implies that the SVL is $100 million per EF. In contrast, the accepted value used by federal agencies for safety policy analysis is approximately $10 million.[12]

PG&E's valuation means that it expects society to value a 1% reduction in the likelihood of occurrence of a single EF at $1 million. In other words, a mitigation that accomplished this and nothing else each year is worth an expenditure of $1 million per year. This is an order of magnitude greater than the values used by U.S. government agencies for many years to weigh environmental and safety regulations that reduce risk.

To comport with accepted values used by federal agencies in risk analysis, the SVL should be reduced to a value of $10 million. As discussed in Part II, Section I below, TURN proposed alternative MAVF scenarios to address this problem.

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12 The most recent values used by the U.S. EPA and U.S. Dept. of Transportation, which are based on studies from the academic literature, can be found in the following documents: U.S. EPA, "What Value of a Statistical Life Does EPA Use." The EPA uses a value of $7.4 million in 2006$, which is approximately $10 million in 2020$. See also, U.S. Dept. of Transportation, "2016 Revised Value of a Statistical Life Guide," August 8, 2016. The DOT uses a value of $9.6 million in 2016$, also equivalent to about $10 million in 2020$. The DOT also estimates the value of a severe injury at 26.6% of the SVL, or about $2.5 million.

3.4. Insufficient and Missing Attributes

The attributes in the MAVF should address all the different factors that affect PG&E's ratepayers, employees, and the public that should be considered in decisions about which risk mitigation activities to pursue. PG&E has identified three of the important attributes at the top level—Safety, Reliability, and Financial Consequences. However, PG&E has not included other attributes that may be important. When attributes are missing, the MAVF has blind spots for types of consequences that are not considered, which could prevent PG&E from identifying the most cost-effective mitigations.

<u>Among the attributes that PG&E failed to include are Environmental Consequences, Customer Satisfaction, and Employee Satisfaction</u>. Ratepayers should expect good performance from PG&E in all these dimensions. <u>Attributes can and should be specified that address each of these impacts.</u>

Further, PG&E's Safety attribute does not distinguish among the safety consequences affecting the public, PG&E employees, and PG&E contractors (fatalities or serious injuries). There is reason to believe that those consequences could be weighted differently.

The natural units of the Reliability attribute are either (electricity) customer minutes interrupted or (gas) customers affected per event. These are insufficiently detailed. Such descriptors as Customer Type (Industrial, Commercial, Retail) and indices such as SAIFI and SAIDI should be used to specify with greater accuracy the effects of a mitigation.

4. Insufficient Transparency

TURN has devoted significant time and resources to trying to understand the basis for imputs and intermediate calculations that have a significant impact on RSEs. While we appreciate the efforts of PG&E's analysts to attempt to explain the details of the calculations, TURN still found it unduly difficult to understand how PG&E determined certain inputs and intermediate outputs in its analysis. Below, we discuss some of the more significant problems we encountered. <u>PG&E should be advised to improve the transparency of its inputs and calculations in the updated analysis for its 2023 GRC</u>.

4.1. Lack of Transparency Regarding Determination of Effects of a Mitigation

The risk reduction of a mitigation is based on a percentage change to LoRE or CoRE (or both) claimed by PG&E as a result of applying a mitigation to a tranche. However, how PG&E determined the reductions claimed for a mitigation over the various subdriver-risk event-outcome combinations within a tranche is not transparent.

As an example, we will describe our efforts to understand the basis for the mitigation effectiveness values for Wildfire Risk mitigations. In workpaper EO-WF-25_Mitigation

Effectiveness WP.xlsx, the worksheet "M2 | Summary Analysis" contains (in column D) effectiveness percentages of system hardening on different driver-subdriver combinations. The worksheet "M2 |SME Input" has 5,095 rows with what appear to be combinations of causes, involved equipment, equipment condition, and, in column F, a "System Hardening Effectiveness" designation. There are four designations "All," "High," "Medium," and "Low." The workpaper never explains what these designations mean, nor how PG&E calculated the very precise effectiveness percentages in Column D in the worksheet "M2 | Summary Analysis."

TURN had to ask a specific data request for what the designations meant and how the effectiveness percentages were calculated. In response, PG&E provided another workpaper, with hundreds of thousands of outages. In that workpaper, TURN-0004-Q01: RAMP-2020_DR-TURN_004-101Atch01, it appears PG&E assigned an assumed effectiveness category to each outage. That is, if the circuit was hardened, what would be the effectiveness on reducing the likelihood of an outage. In column CJ of the worksheet, "All Outages Data Set," of this workpaper, we learn the meaning of the four designations. ("All" = 90%, "High" = 70%, "Medium" = 50%, "Low = 20%). Again, however, there was no discussion of how the effectiveness percentages in EO-WF-25_Mitigation Effectiveness WP were calculated. Nor was this discussed in the Workpaper User Guide or RAMP filing. It was not until a session with PG&E that we were told PG&E aggregates all of these individual values by subdriver, e.g., all of the balloon outages, animal outages, etc., and then calculates the average effectiveness values for each subdriver based on the assumed individual outage effectiveness levels.

An inability to determine how effectiveness percentages were calculated for Wildfire mitigations from documentation or workpapers PG&E provided with its filing does not meet the transparency requirement of the Settlement.

4.2 Lack of Clarity Regarding How LoRE is Determined

PG&E's Report and documentation is not clear regarding how LoRE is defined and measured, both pre- and post-mitigation. A key problem is that PG&E has not made clear whether PG&E is using: (1) joint probabilities, i.e., the probability of joint occurrences of multiple events; or (2) conditional probabilities, i.e, the probability of an event given the occurrence of another event or events. PG&E's documentation did not specify the computations sufficiently to clarify this difference.

This is very important because how PG&E defines LoRE at the tranche/subdriver/outcome level determines how PG&E computes the total LoRE (which PG&E says is aggregated), how it computes the risk score, and how it assesses the effectiveness and cost of a mitigation.

For example, consider a mitigation that is said to reduce the LoRE in relation to the subdriver balloons and the outcome ignition by some percentage, say 50%. PG&E is not clear whether that means that the probability of occurrence of the subdriver balloons has been reduced by 50% or that the conditional probability of the occurrence of the outcome ignition given the subdriver balloons has occurred is reduced by 50%. Nor do we know which type of probability PG&E's experts had in mind when they said that the mitigation is 50% effective.

Further, the costs of two different mitigations that will do either will almost surely differ. It is reasonable to expect that the cost of reducing the incidence of balloons by 50% is different from the cost of reducing by 50% the likelihood of occurrence of an ignition after a balloon has struck. We do not know which costs apply because we do not know how the LoRE is defined.[13]

The lack of clarity regarding how PG&E's LoRE values are determined create significant problems in assessing the reasonableness of PG&E's risk scores and RSE calculations.

5. Failure to Account for Full Scope of Adverse Consequences from PSPS

An important issue is whether PG&E fully accounted for all of the risks from PSPS events in its analysis.

PG&E admits that it did not take into account any safety risks from PSPS. This runs contrary to what we now know about the dangers to health and safety from being without power for extended periods. These include:

- Risks of fire or carbon monoxide poisoning from improper use of generators[14] and other harms to health (respiratory, increased cancer risk) from use of gasoline or diesel-powered generators.[15] As PSPS events now seem to be a long-term strategy for PG&E and the pandemic makes it more essential to have power, increasing numbers of homes and businesses can be expected to resort to use of generators.

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[13] An example is found in PG&E's file WP-User Guide-1.xlsb. In tab Input LoRE, row 4, column F is the number 0.003623188. Is this the probability of the joint occurrence of the tranche Not A Current Replacement Priority and the sub-driver Primary Cable Failure and the outcome Asset Failure/Not Catastrophic? Or is this the conditional probability of the joint occurrence of the sub-driver Primary Cable Failure and the outcome Asset Failure/Not Catastrophic *given* the occurrence of the tranche Not A Current Replacement Priority? Or is this the conditional probability of the occurrence of the outcome Asset Failure/Not Catastrophic *given* the joint occurrence of the tranche Not A Current Replacement Priority and the sub-driver Primary Cable Failure? Or is it something else? Nowhere is it clearly stated. So we do not know.

[14] An overloaded generator used during a PSPS event is suspected of causing a fire in the Oakland hills that burned two houses: https://www.sfgate.com/california-wildfires/article/Oakland-Hills-fire-homes-red-flag-warning-15678536.php

[15] https://ww2.arb.ca.gov/sites/default/files/2020-01/Emissions_Inventory_Generator_Demand%20Usage_During_Power_Outage_01_30_20.pdf

- Inability of some customers to access 911 when power is out. A home fire in San Anselmo earlier this week in which a person died could not be promptly reported to 911 because of the PSPS outage.[16]
- Increased risk of fire from use of candles for lighting.
- Increased risk of accidents (falls and traffic accidents) when power is out
  Health impacts of lost use of medical devices (many customers who are eligible for medical baseline may not be contacted by PG&E)

While PG&E states that it does include some of the non-safety impacts of PSPS in the Reliability consequence attribute, the scope of the financial harms suffered by society that are included in PG&E's analysis is unclear. Initially in the workshops, PG&E claimed that it viewed harms such as economic losses to businesses and workers as "indirect" consequences that it did not include in its analysis. However, in a Scenario Analysis call on October 28, 2020, PG&E asserted for the first time that its Reliability attribute counts such economic losses. PG&E needs to further substantiate this new contention, which TURN has not been able to probe in time for these comments.

In any event, PG&E's assessment of the detriments from PSPS is clearly deficient in light of the failure to consider the evident safety risks from extended loss of power to homes, businesses and municipal lighting, including street lights. In this respect, it is clear that PG&E has overstated the RSE of PSPS as a mitigation for wildfire risk. And further study is needed to assess the extent to which PG&E fails to fully capture economic risks to society.

<u>PG&E should be advised to remedy the deficiencies in its PSPS analysis in the revised analysis it undertakes for the GRC</u>.

6. Aggregation of Wildfire Mitigations that Should be Separately Assessed

The usefulness of PG&E's RAMP analysis is diminished whenever it groups different mitigation activities together and only provides an RSE for an aggregated group. For example, PG&E did not assess targeted undergrounding separate from covered conductor installation, instead including both mitigations under the single aggregated mitigation it calls System Hardening (M2). As a result, in PG&E's analysis, the parties and CPUC are unable to compare the RSEs of these two independent mitigations.

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[16] https://seattle.cbslocal.com/video/4822592-elderly-woman-dies-in-san-anselmo-house-fire/

The two most glaring examples of inappropriately aggregated mitigations were both in the Wildfire Risk chapter. What PG&E calls Enhanced Vegetation Management (EVM) (M1) actually consists of four different types of activities:[17]

A. Enhanced radial clearance;

B. Overhang trimming;

C. Identification and mitigation of trees with the potential to strike; and

D. Fuel reduction.

Similarly, what PG&E calls System Hardening actually consists of six different activities:[18]

A. Replacement of bare overhead primary and secondary conductor with covered conductor, including pole replacements where necessary to support new, heavier conductor;[19]

B. Pole replacements unrelated to the installation of covered conductor, if applicable;

C. Replacement of existing primary line equipment (this should be further broken out by type of equipment e.g. fuses, switches, etc.)

D. Replacement of existing transformers with models that contain fire resistant FR3 insulation fluid;

E. Undergrounding; and

F. Circuit removal.

<u>For its updated GRC analysis, PG&E should be advised to provide costs, risk reductions, and RSEs for each of these individual activities</u>.

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[17] See pp. 10-34-35 of PG&E's RAMP filing.

[18] PG&E RAMP Filing, pp. 10-35-36.

[19] Necessary pole replacements shall be quantified and incorporated into the unit cost (dollars per circuit mile) of covered conductor in a transparent manner. PG&E should include only those pole replacement costs that are necessary to support the additional weight of covered conductor, and should transparently calculate the unit cost of covered conductor installation, documenting all assumptions.

7. Elements Missing from PG&E's Analysis

7.1 Assessment of Mitigations that PG&E Calls "Controls"

PG&E states that the schedule for this RAMP did not allow it to assess mitigations that are currently in place, which it refers to as "controls." Contrary to PG&E's claim,[20] nothing in the RAMP Settlement Agreement carved out "controls" from the mitigations that are required to be assessed under Step 3 of the Settlement. Row 26 requires the RAMP filing to provide a ranking of "all RAMP mitigations" by RSE. If controls were to be excluded from this requirement, this exclusion would have been made clear in Row 26, or elsewhere in the Settlement. There is no such carve-out language in the Settlement, and TURN remains surprised and disappointed that PG&E has taken this position, which is very different from what TURN understood the parties to be agreeing to.

In addition, as SPD is aware, SPD's predecessor criticized PG&E's practice of not assessing controls in SED's report on PG&E's previous RAMP filing.[21]

Wildfire vegetation management (VM) provides an example of the importance of assessing all mitigations, whether new or current. Much of the PG&E's VM mitigation work is done under what PG&E refers to as its "routine" or "compliance" programs. PG&E's Report only assesses "enhanced" vegetation management (EVM), which (as discussed in Section 6 above) consists of a variety of different programs to supplement the routine work. PG&E's Report does not provide RSEs for any of the routine/compliance programs it conducts at huge ratepayer expense.

However, the boundary between routine/compliance work and enhanced VM is unclear. In HFTDs, the recommended clearance distance at time of trimming is now 12 feet (increased from 4 feet), which raises the question of whether trimming to 12 feet is now the current routine practice (which would make it a "control" in PG&E's parlance) or enhanced. In addition, it is unclear whether removal of dead and dying trees that could come into contact with utility lines is "routine" or "enhanced." Utilities have argued that such work is required under ESRB-4, yet such work needs to be distinguished from removal of green, living trees which is definitely not required work. Rather than drawing difficult lines concerning what constitutes "control" work, all major mitigation programs should be evaluated.

Moreover, without an assessment of the cost-effectiveness of the routine VM work, it is not possible to evaluate the *incremental* cost-effectiveness of the various EVM programs which are

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[20] PG&E RAMP Report, p. 3-53.

[21] SED Report, I.17-11-003, March 30, 2018, p. 4.

also extremely costly.[22] The cost effectiveness of *all* VM programs as compared to other Wildfire mitigation efforts needs closer scrutiny from the Commission, as, after each PSPS event, PG&E routinely reports numerous tree contacts that could have sparked a wildfire had lines been energized. These reports are an admission of ineffective or failed vegetation management, and the public has the right to ask whether VM programs are cost effective -- particularly as new technologies such as REFCL are emerging as alternative and potentially more cost-effective wildfire mitigation measures.

PG&E's Report suggests that it *may* assess mitigations in place for its GRC filing, but PG&E remains non-committal about whether and to what extent it will do the required assessments.[23] This is unacceptable. <u>PG&E should be advised that it will be expected to provide RSEs for all mitigations, whether new or in place, in the updated analysis it provides in its GRC</u>.

7.2 Assessment of the Incremental Benefits of a Mitigation Where Another Mitigation Is Previously Deployed

As shown on PDF pages 30-31 of PG&E's July 14, 2020 Workshop slides, PG&E made an effort to account for the fact that, when multiple mitigations are applied to a risk, the risk reduction of each individual mitigation is reduced. PG&E showed how, in such cases, it allocated risk reduction based on the marginal risk reduction benefits of each mitigation.

However, PG&E's approach only helps when it has already been determined that multiple mitigations will be used, which is a classic example of putting the cart before the horse. In some, perhaps many, situations in which there are multiple mitigations that can be deployed, a key question that this analysis is designed to help with is what are the RSEs when one mitigation is deployed as the *primary* mitigation (i.e, deployed first) and another is applied, if at all, only as a *supplement* to (i.e., after) the primary mitigation has been performed. PG&E's analysis does not answer this important question of the *incremental* benefits of applying a second mitigation after a first mitigation has been deployed.

Think of, for example, REFCL in relation to other wildfire mitigations. Assuming REFCL is as effective in preventing ignitions as hoped, then REFCL would be a good candidate to serve as a primary wildfire mitigation, particularly given its relative lower cost. An important question then would be, what are the incremental RSEs of applying covered conductor (CC) or vegetation management (VM) after REFCL has been deployed. PG&E's analysis does not

[22] WSD has criticized the utilities generally, and PG&E specifically, for failing to assess the incremental benefits of "enhanced" mitigations in comparison to routine activities. *See, e.g,,* WSD-02 (Guidance applicable to all utilities), p. 26; WSD-03 (PG&E), pp. 33-34.

[23] PG&E RAMP Report, pp. 3-53 to 3-54.

address this issue -- or the related issue of what are the incremental benefits of CC and VM after the other has been deployed.

To show the shortcomings of PG&E's portfolio allocation approach, consider the following example. M1 and M2 are two mitigations each with 80% effectiveness. Under PG&E's allocation approach, the two mitigations together would achieve 96% effectiveness and each mitigation would be determined to be 48% effective. PG&E's RSEs would be based on 48% effectiveness for each mitigation.

However, if M1 is deemed the *primary* mitigation (e.g., because, like REFCL it is relatively inexpensive), then it should be viewed as having 80% effectiveness and M2, the supplemental mitigation, should be viewed as having only 16% incremental effectiveness. When these effectiveness values are used, the RSEs could be very different from the RSEs that PG&E calculated. These *incremental* RSEs are missing from PG&E's analysis and are critical information to help the parties and the Commission in their analysis of the optimal portfolio of mitigations.

Accordingly, <u>where decisions about the deployment of multiple mitigations (including mitigations that PG&E calls controls) need to be made, PG&E needs to augment its analysis to show incremental RSEs based on the order of deployment of the mitigations</u>. This results in a more accurate measurement of the marginal or incremental value of a mitigation. As indicated above, this type of analysis is particularly necessary for Wildfire Risk mitigations, where a variety of mitigations can be used to prevent ignitions.

PART II

<u>Discussion of Scenario Analyses</u>

This Part of TURN's informal comments discusses the alternative scenarios that TURN has asked PG&E to perform to date and provides TURN's interpretation of the results. In addition, we briefly discuss the implications of the important REFCL scenario requested by SPD.[24]

1. TURN Scenarios to Increase Granularity of Wildfire Risk Analysis

TURN requested alternative Wildfire scenarios to attempt to address two of the problems discussed in Part I above – insufficient granularity of tranches (Section 1.2) and inappropriate aggregation of mitigations (Section 6).

[24] TURN did not have sufficient time to review in any detail the other scenarios. Accordingly, our silence concerning those other scenarios does not mean we view them as unimportant.

1.1 Breakdown of Mitigations by Component Programs

TURN requested that System Hardening and EVM be broken down into their component programs. The results provided by PG&E show, as expected, that RSEs vary considerably among the component programs, providing richer, more useful information for the Commission and parties. For example, slide 18 of the TURN Wildfire Scenario results shows that undergrounding has a much lower than average RSE among the SH programs.[25] Similarly, slide 19 shows that, for all scenarios, tree removal had a very low RSE compared to the average for all EVM programs, whereas overhang trimming had a relatively high RSE. These program-by-program results provide interesting and important information. <u>PG&E should be advised to provide RSEs for each of these component programs in its updated GRC analysis</u>.

1.2 Improved Granularity of Tranches

As noted in Part I, Section 1.2, PG&E based its analysis on excessively large tranches, including the approximately 7,000 mile HFTD – Distribution To Be Hardened tranche and the approximately 18,000 HFTD – Distribution Remainder tranche. Based on a system hardening risk prioritization analysis that PG&E had performed for its 2020 GRC based on circuit protection zones, TURN asked PG&E to break down these two tranches into 12 tranches, so that, in total, PG&E would have 18 tranches, instead of the 8 used in PG&E's Report. To be clear, TURN is in no way indicating that its breakdown of tranches is either ideal or adequate. The Settlement requires much more granularity than TURN requested, and TURN fully expects that its more granular tranches still mask significant differences in LoRE and CoRE among the assets included in those tranches. In addition, using more up-to-date data to group the more granular tranches would be a good idea.

Still, at the big picture level, the results of TURN's scenarios show that, using more granular RSEs will provide more accurate information for the upcoming GRC.

One lesson is that more granular tranches allow PG&E to more accurately reflect the risk reduction benefits of mitigation work that is expected to be completed before the next GRC period starts in 2023. Slide 6 of the PG&E Results shows that the SH work to be performed prior to 2023 will generally be done in the highest risk tranches until the work is exhausted. TURN's scenarios show that this work will be concentrated in TURN's tranches 2-4. By more accurately showing the risk reduction that will occur from the pre-2023 work, the starting Wildfire Risk scores under TURN's scenarios are lower (roughly 20,000 on Slide 13) than the approximately 25,000 score in PG&E's Report (Slide 12).

[25] In Scenario TURN-1a, the aggregate SH RSE is 22.1, but the undergrounding mitigation RSE is only 9.0. The same relationship holds true for Scenario TURN-2a.

Another lesson is that TURN's more granular risk analysis better reflects the higher risk reduction that can be obtained when mitigations are focused on the highest risk tranches. For example, as shown on Slide 18, PG&E's SH (M2) aggregated RSE is 7.4, compared to an aggregated SH RSE of 25.4 under Scenario TURN-2a (which uses TURN's preferred MAVF). The difference is because PG&E's analysis incorrectly assumes that the 2100 miles of SH work in 2023-2026 that PG&E is proposing to perform would be spread equally across all 7,000 miles of its "To Be Hardened" tranche, instead of being generally focused in the remaining highest risk tranches captured in TURN's scenario. With tranches that better reflect the homogenous risk profiles required by the Settlement (TURN's tranches 2-9 are artificially grouped to each reflect 10% of the total risk), we can expect to see declining RSEs as the mitigation work moves from higher to lower risk tranches.

And perhaps the most important big picture lesson is that PG&E can carry out an analysis based on more granular tranches that what it performed for the RAMP Report. TURN's tranches should pave the way for a revised Wildfire analysis for the GRC that uses much more granular tranches.

At a more micro level, TURN is not able to indicate at this time whether it agrees with PG&E's specific RSE scores for TURN's scenarios. One question is whether PG&E is overestimating mitigation effectiveness for sub-drivers in each tranche. PG&E's sub-driver effectiveness values appear to be based on allocations of ignitions to each tranche. However, PG&E does not know the locations of ignitions. Hence, PG&E allocates ignitions by sub-driver cause using outage data, for which it has individual circuit protection zone locations. In other words, at the tranche level, PG&E defines risk based on *outages*, not ignitions. The company then uses a calculated fraction of ignitions relative to outages (e.g., 100 balloon-caused outages and 2 balloon-caused ignitions, for a fractional value of 0.02) to allocate ignitions to each tranche. However, if a tranche has zero sub-driver ignitions allocated to it, then PG&E assumes that sub-driver cannot cause an ignition in the future. For example, if an animal has never caused an outage and ignition in a given tranche, PG&E assumes there can never be an animal-caused ignition in the future in that tranche. PG&E has acknowledged that this is a problematic assumption.

In addition, PG&E's computations are not sufficiently documented to provide transparency. For example, PG&E may be revising its CoRE estimates as part of the definitions of the more granular tranches, but that is still unclear to TURN. As with PG&E's Report, we repeatedly have had to ferret out how PG&E has performed its analyses. In each of our conversations, PG&E has revealed additional information about its calculations that should have been readily shared. We recognize that PG&E has been busy with many scenario analyses, but PG&E's leadership needs to ensure that PG&E has the resources to meet the transparency requirements of the Settlement.

Notwithstanding these calculational concerns in the results provided by PG&E, TURN believes that its Wildfire scenarios resoundingly demonstrate the importance of satisfying the Settlement's tranche granularity requirements. PG&E should be advised to work with the parties to develop a much more granular set of tranches for the Wildfire risk to determine RSEs for PG&E's upcoming GRC filing**.**

2. TURN Scenarios to Modify PG&E's MAVF

TURN requested scenarios to three of the problems with PG&E's MAVF discussed in Part I, Section 3: (i) non-linear scaling functions that lead to tradeoffs which are unrealistic; (ii) a statistical value of life (SVL) that is ten times greater than the accepted value used by federal agencies to assess safety policies; and (iii) an inappropriate cap on PG&E's scaling functions, which mean that adverse consequences beyond a certain point (e.g., 100 fatalities in a wildfire) have no avoidance value.

The specific scenarios were:

- MAVF-TURN-01 reduced the SVL to $10 million from PG&E's assumed $100 million. This scenario retained PG&E's nonlinear and capped scaling functions for all attributes. Hence, the only change to the scaling functions is to move the upper bound of the Safety attribute to 1000. The Reliability and Financial attributes were unchanged.

- MAVF-TURN-02 changed the scaling functions to linear for the Safety and Financial Consequences attributes. One benefit of linear scaling is that there is no need to perform any Monte-Carlo analysis, which would simplify PG&E's analysis and improve transparency.[26] The SVL was restored to $100 million, the value that PG&E originally selected. The caps were removed from the Safety and Financial Consequences scaling functions. The Reliability attribute scaling function was unchanged.

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[26] The MAVF is used to determine the expected scaled value of an attribute when the level *X* of the attribute is uncertain. If the scaling function is nonlinear, then the computation to find that expected scaled value can be complicated, depending on the nature of the nonlinearity of the scaling function and the probability distribution of the attribute level *X*. But if the scaling function is linear, then the expected scaled value is equal to the scaled value of the expected level of the attribute. Because the expected value of the attribute is an input to any Monte-Carlo simulation, the simulation is no longer necessary: the Monte-Carlo simulation will result in the same expected value that is used to perform it. For example, if the expected number of deaths from a catastrophic wildfire is 16, the range of natural units is between 0 and 100 deaths, and there is a linear scaling function between 0 and 100 scaled units, then the expected value of the scaled units is also 16. If the scaling function is linear between 0 and 1,000 deaths, then the expected value of the scaled units is 1.6. Thus, there is no need to perform a Monte-Carlo analysis to determine the expected value of the scaled units.

- MAVF-TURN-03 changed the scaling functions to linear for the Safety and Financial Consequences attributes, and changed the SVL to $10 million, the value specified in MAVF-TURN-01. The caps were removed from the Safety and Financial Consequences scaling functions. The Reliability attribute was unchanged. Thus, MAVF-TURN-03 combined the changes in MAVF-TURN-01 and TURN-02. For the reasons given in Part I, Section 3, TURN believes that MAVF-TURN-03 will lead to the best scoring of consequences compared to PG&E's MAVF and the other two TURN scenarios.

The results of these scenarios lead TURN to conclude the following:

- PG&E's caps on the scaling functions underestimate risk. For the Wildfire risk, for example, uncapping the scaling functions (MAVF-TURN-02) increases the total risk score by about 50%.

- PGE's nonlinear scaling functions cause the risk of events with relatively small consequences to be underestimated. PG&E's (and our) analysis shows that, using linear scaling functions increases the estimated risk of relatively small-consequence events by a factor of ten. This is a more accurate reflection of risk, given that an equivalent safety or financial impact (i.e, 1.0 EF or a $1 million loss) should be given the same value whether it occurs as a result of a risk event with relatively small consequences or one with catastrophic consequences. (See Part I, Section 3.1).

- PGE's choice of SVL = $100 million causes the Safety consequence scores to be overestimated. Consequently, safety has an exaggerated contribution to total risk. This matters because there must be a tradeoff made between the costs to ratepayers of reducing safety risks and the benefits of those reductions. Using a $100 million SVL will distort those tradeoffs.

The TURN MAVF scenarios change PG&E's pre-mitigation risk rankings, the post-mitigation risk levels, and the RSE rankings of risks. The differences between TURN's preferred scenario and PG&E's MAVF are significant for some risks and mitigations but in most instances, the differences are less than 25% for total risk scores and RSEs.

<u>PG&E should be advised to present its updated results for the GRC using TURN-MAVF-3 -- or at least present a set of results that reflect this scenario</u>**.**

3. REFCL Scenario

The REFCL Scenario shows that REFCL is a highly promising technology. Its RSE of 126 far exceeds the RSE for any other Wildfire Risk mitigation. Accordingly, where its deployment makes sense, it has the potential to serve as the primary mitigation. Depending on the results of PG&E's pilot in March 2021, broad scale deployment could start shortly thereafter, with the main constraint being availability of necessary equipment. In short, REFCL has the potential to have a very significant effect on PG&E's portfolio of mitigations.

PG&E's updated results for the 2023 GRC should include an alternative mitigation plan in which REFCL is deployed as fast as projections of equipment availability allow. This alternative plan should treat REFCL as the primary mitigation for circuits where REFCL is expected to be effective and optimize the use of other mitigations, including covered conductor and vegetation management, as supplemental mitigations**.** PG&E should be ready to update this analysis during its GRC proceeding. Under no circumstances should risk analysis that takes into account REFCL as a mitigation be deferred to the 2027 GRC.

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