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PROPOSED DECISION

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11/4/2021 Item #18

Decision **PROPOSED DECISION OF COMMISSIONER RECHTSCHAFFEN**
(Mailed 9/17/2021)

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF
CALIFORNIA**

Order Instituting Rulemaking to
Further Develop a Risk-Based
Decision-Making Framework for
Electric and Gas Utilities.

Rulemaking 20-07-013

DECISION ADDRESSING PHASE I, TRACK 1 AND 2 ISSUES

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Appendix A – Adopted Safety and Operational Metrics for Application to PG&E

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Appendix G – Glossary of Terms

DECISION ADDRESSING PHASE I, TRACK 1 AND 2 ISSUES**Summary**

This decision addresses Phase I, Track 1 and 2 issues. We adopt 32 Safety and Operational Metrics for Pacific Gas and Electric Company (PG&E), to be used in accordance with Decision (D.) 20-05-053, which approved PG&E's post-bankruptcy reorganization plan. We require PG&E to report on these Safety and Operational Metrics every six months starting March 31, 2022. The metrics are included in Appendix A.

We adopt 10 new Safety Performance Metrics (SPMs), building on those adopted in D.19-04-020, for application to PG&E, Southern California Edison Company (SCE), Southern California Gas Company, and San Diego Gas & Electric Company. We delete four and modify 19 of 26 existing SPMs for a total of 32 SPMs. These are included in Appendix B.

We modify the "Transparency Guidelines" proposed by PG&E and require SCE to test these and serve the completed test documents to the SCE 2022 Risk Assessment and Mitigation Phase (RAMP) proceeding service list no later than 60 days from filing its 2022 RAMP report. We will consider formally adopting these guidelines in a subsequent decision. The Transparency Guidelines as modified in this decision are contained in Appendix C.

We approve minor technical clarifications to the Risk-Based Decision-Making Framework adopted in D.18-12-014. We adopt a 2021 Safety Model Assessment Proceeding (S-MAP) Revised Lexicon, included in Appendix D. Finally, we formally establish a Technical Working Group for this proceeding and identify issues in scope for this group, including developing an updated S-MAP Roadmap to help guide Phase II of this proceeding. A glossary of terms used in this decision is included in Appendix G.

This proceeding remains open.

1. Background

On November 14, 2013, the California Public Utilities Commission (Commission) opened Rulemaking (R.) 13-11-006 *Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the Rate Case Plan for Energy Utilities* (Risk Rulemaking). The purpose of the Risk Rulemaking was to incorporate a risk-based decision-making framework into the Rate Case Plan (RCP) for the energy utilities' General Rate Cases (GRCs), in which utilities request funding for safety-related activities. The RCP guides utilities on the type of information that is presented and the procedural schedule to be followed to address revenue requests in their GRCs.

In response to the Risk Rulemaking, and as a result of Senate Bill (SB) 705, and its emphasis on making natural gas safety a top priority, the Commission modified the RCP framework in Decision (D.) 14-12-025 *Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan* (Risk Decision). The Risk Decision establishes the basic parameters and process for integrating risk assessments into the GRCs of the large investor-owned utilities (IOUs) including Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). Transparent risk-based decision-making approaches and associated parameters assist the Commission and interested parties in evaluating how energy utilities assess, manage, mitigate, and minimize safety risks.

The Commission in D.14-12-025 recognized it would take time to fully develop a risk-based decision-making approach. To assist with this process, D.14-12-025 directs the IOUs to present their risk-based decision-making models

in a “Safety Model Assessment Proceeding (S-MAP)” in 2015 and every three years thereafter. D.14-12-025 also orders the IOUs to file a summary of their risk-based decision-making processes and risk mitigation plans in a “Risk Assessment and Mitigation Phase (RAMP)” report, filed one year before each IOU’s GRC application, for review by stakeholders and Commission Staff.

On May 15, 2015, the IOUs each filed an S-MAP application, establishing the Application (A.) 15-05-002 *et al* proceeding (S-MAP proceeding). On August 18, 2016, the Commission adopted D.16-08-018 *Interim Decision Adopting Multi-Attribute Approach (Or Utility Equivalent Features) and Directing Utilities to Take Steps Toward a More Uniform Risk Management Framework* (Interim Decision). The Interim Decision directs the IOUs to take steps to develop a more uniform approach to risk management and to test an approach proposed by intervenors towards this end. The Interim Decision adopts minimum requirements for RAMP filings, an initial “Lexicon” of terms relating to the S-MAP and RAMP frameworks, emphasizes the importance of risk-spend efficiency (RSE) calculations in ranking risks, and adopts an interim S-MAP Roadmap to move from the relative risk scoring frameworks contained in the IOUs’ May 2015 filings to more quantified methods for optimized risk mitigation.

On December 13, 2018, the Commission adopted D.18-12-014, *Phase Two Decision Adopting Safety Model Assessment Proceeding Settlement Agreement with Modifications* (SA Decision) in the S-MAP proceeding. The SA Decision adopts requirements for a Risk-Based Decision-Making Framework (RDF) proposed in a Settlement Agreement developed by most parties and additionally requires a minimum 40 percent weighting to safety issues when implemented. The SA Decision adopts a 2018 Revised S-MAP Lexicon and an updated S-MAP Roadmap.

In brief, the RDF adopted in the SA Decision requires IOUs to:

- Employ consistent methods to identify and prioritize risks;
- Model risk impacts in a “Multi-Attribute Value Function” (MAVF) across three required risk categories (safety, financial, reliability), and other categories as desired, and assign a weight to the categories;
- Assign a minimum 40 percent weight to the category of safety impacts;
- For risks representing the top 40 percent of safety impacts greater than zero, use a probabilistic, quantitative approach to estimate the likelihood and consequences of risk events across the required and optional risk impact categories;
- Translate all impacts of risk events into a 100-unit scale;
- Include a bow tie¹ illustration for each risk and each mitigation, and identify which element(s) of its associated bow tie the mitigation addresses;
- Include in the RAMP the top 40 percent of risk events as ranked by safety category risk scores only, computed using the MAVF, analyze these risks using the full MAVF, including all risk impact categories, and compute RSE scores for all mitigations; and,
- Rank (prioritize) all mitigation options by RSE scores.

D.19-04-020 subsequently adopted 26 Safety Performance Metrics (SPMs) to apply to all four IOUs. D.19-04-020 requires IOUs to annually file SPM reports in their respective open or most recent GRC proceeding. D.19-04-020 closed the S-MAP Proceeding and indicated the Commission would open a rulemaking to

¹ Decision 18-12-014 defined bow tie as follows: A tool that consists of the Risk Event in the center, a listing of drivers on the left side that potentially lead to the Risk Event occurring, and a listing of consequences on the right side that show the potential outcomes if the Risk Event occurs.

consider additional risk-based decision-making questions instead of requiring a second IOU S-MAP filing as envisioned in the Risk Decision.

On May 28, 2020, the Commission adopted D.20-05-053 in Investigation (I.) 19-09-016.² D.20-05-053 approved a reorganization plan for PG&E subsequent to that utility's declaration of bankruptcy in January 2019. D.20-05-053 calls for the development of Safety and Operational Metrics (SOMs) applicable to PG&E to be used in conjunction with the Enhanced Oversight and Enforcement Process (EOE Process) adopted in that decision. As described in later sections of this decision, the EOE Process is designed to ensure that PG&E is improving its safety and operational performance and provides for enhanced reporting by PG&E and expanded Commission oversight in the event that PG&E's performance is unsatisfactory.

2. Procedural Background

On July 16, 2020, the Commission opened Rulemaking (R.) 20-07-013 in an Order Instituting Rulemaking (OIR) *to Further Develop A Risk-Based Decision-Making Framework for Electric and Gas Utilities* (RDF Proceeding). The OIR sets forth an ambitious set of issues to further refine our regulatory tools to promote the highest degree of safety performance from electric and gas utilities, consistent with Public Utilities Code Section 451 requirements to ensure just and reasonable rates.³

² *Order Instituting Investigation on the Commission's Own Motion to Consider the Ratemaking and Other Implications of a Proposed Plan for Resolution of Voluntary Case filed by Pacific Gas and Electric Company*, pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Corporation and Pacific Gas and Electric Company, Case No. 19-30088.

³ Hereafter, all references to code are to the Public Utilities Code unless otherwise stated.

The Assigned Administrative Law Judge (ALJ) held a prehearing conference on September 15, 2020. On November 2, 2020, the Assigned Commissioner issued a Scoping Memo and Ruling (Scoping Memo) that identifies issues in scope and adopts a schedule for rulemaking, to be addressed in two phases. The Scoping Memo identifies the following issues for Phase I of this proceeding:

- **Track 1: Clarifying RDF Technical Requirements:** Track 1 considers whether there are discrete technical questions regarding the RDF that the Commission should clarify in the short term (with larger, more substantive revisions to the RDF to be considered in Phase II).
- **Track 2: Safety and Operational Performance Metrics:** Track 2 considers safety and operational performance metrics and their application broadly. This work addresses development of SOMs for PG&E as directed in D.20-05-053. This track will also consider the need for new SPMs or revisions to existing SPMs adopted in D.19-04-020.
- **Track 3: Refining RAMP and Related Procedural Requirements:** Track 3 focuses on whether there are RAMP, GRC and Risk Spending Accountability Report (RSAR) procedural or definitional requirements that the Commission should refine or clarify.
- **Track 4: Small and Multijurisdictional Utilities (SMJUs):** Track 4 focuses on whether the Commission should review and/or update the SMJU Voluntary Agreement included in D.19-04-020, and/or adopt RAMP, RSAR or other related requirements for the SMJUs.

The Scoping Memo indicates that work in each of the tracks would be conducted in working groups led by Commission Staff.

On November 17, 2020, the Assigned Commissioner issued a *Ruling Regarding Development of Safety and Operational Metrics* (SOMs Ruling) to advance Track 2 issues. Commission Staff convened a workshop to discuss Track 1 issues

on December 15, 2020. On January 15, 2021, PG&E filed a set of proposed SOMs in response to the SOMs Ruling (Track 2). On January 25, 2021, the Utility Reform Network (TURN), the Public Advocates Office (Cal Advocates), SCE, and SDG&E and SoCalGas (SDG&E/SoCalGas) filed comments on PG&E's proposed SOMs (Track 2). On January 28, 2021, Commission Staff convened a Track 2 workshop to discuss PG&E's proposed SOMs and parties' comments on the proposed SOMs. Mussey Grade Road Alliance (MGRA) filed authorized late-filed comments on PG&E's proposed SOMs on February 17, 2021.

On February 1, 2021, the Assigned ALJ issued a *Ruling Requesting Additional Information and Party Comments* regarding Track 2 issues. On February 12, 2021, PG&E filed a response to the ALJ's February 1, 2021 ruling regarding Track 2 issues. On March 1, 2021, PG&E, Cal Advocates, TURN, SCE, SDG&E/SoCalGas, MGRA, and the Protect Our Communities Foundation (PFC) filed comments in response to the Assigned ALJ's February 1, 2021 ruling regarding Track 2 issues. On March 29, 2021, the Assigned ALJ issued a ruling updating the procedural schedule.

Commission Staff convened eight Track 1 working group meetings between February 2021 and August 2021.⁴ Between April 2021 and August 2021 Commission Staff convened three meetings of the Track 2 working group.⁵ Commission Staff noticed all working group meetings to the Service List of R.20-07-013 and to the Commission's Daily Calendar.

On June 4, 2021, the Assigned ALJ issued a *Ruling Providing Staff Recommendations for Comment*. The ruling appended Safety and Policy Division

⁴ February 3, 2021, March 10, 2021, April 14, 2021, May 6, 2021, June 24, 2021, July 16, 2021, July 28, 2021, and August 18, 2021.

⁵ April 1, 2021, May 4, 2021, and August 19, 2021.

(SPD) Staff's recommendations on Track 1 and Track 2 issues (Staff Proposal) and requested party comments. On June 29, 2021, PG&E, SCE, SDG&E/SoCalGas, TURN, PCF, Cal Advocates, MGRA, and the Utility Consumer's Action Network (UCAN) filed comments on the Staff Proposal. On June 30, 2021, SDG&E/SoCalGas filed an amendment to Table 1 of their June 29 comments.

On July 9, 2021, MGRA, Cal Advocates, UCAN, PCF, TURN, SCE, PG&E, and SDG&E/SoCalGas filed reply comments on the Staff Proposal.

3. Jurisdiction

Section 963(b)(3) states that it is the policy of the state of California that the Commission and each gas corporation place safety of the public and gas corporation employees as the top priority and that the Commission shall take all reasonable and appropriate actions necessary to carry out a safety priority policy consistent with the principle of just and reasonable cost-based rates. Section 961(b)(1) requires gas corporations to develop plans for the safe and reliable operation of facilities that implement Section 963(b)(3) requirements.

Section 750 requires the Commission to develop formal procedures to consider safety in a rate case application by an electrical corporation or gas corporation which must include a means by which safety information acquired by the Commission through monitoring, data tracking and analysis, accident investigations, and audits of an applicant's safety programs may inform consideration of the application. Section 321.1(a) requires the Commission to assess and mitigate the impacts of its decisions on customer, public and employee safety.

Section 451 requires the Commission to ensure that electric and gas utilities adopt just and reasonable rates.

4. Issues Before the Commission

This decision addresses Phase I, Track 1 and Track 2 issues as identified in the Scoping Memo. Phase I, Track 3 and Track 4 issues will be addressed in subsequent decision(s).

Track 1: Clarifying RDF Technical Requirements

Should the Commission clarify aspects of the RDF adopted in D.18-12-014:

- a. Do the terms “mitigations” and “controls” need to be defined? Should “mitigations” and “controls” be treated in the RDF using the same methodology?
- b. How should public safety power shutoff (PSPS) events and other utility activities with high customer impacts be treated in the RDF?
- c. Can the Commission identify any guiding principles, best practices, aspirational characteristics and/or minimum requirements for developing a MAVF?
- d. How should the mitigation impacts of data gathering (inspections and patrols) or foundational elements (technology tools) be estimated or measured in the RDF?
- e. Other related clarifications, including Staff recommendations regarding consideration of climate change impacts in Phase II and methods to increase data transparency.

The Scoping Memo identified the following Phase I Track 2 issues:

Track 2: Safety and Operational Performance Metrics

- a. What safety and operational performance metrics should be developed pursuant to D.20-05-053 addressing PG&E’s reorganization plan?
- b. Should the safety and operational performance metrics apply to all IOUs? How should the Commission use the adopted safety and operational performance metrics?

- c. Should the Commission adopt performance criteria or targets for safety and operational performance metrics at the same time it adopts the metrics, or at a later time?
- d. Should the Commission refine any of the 26 safety performance metrics adopted in D.19-04-020? Should the Commission adopt additional safety performance metrics to those adopted in D.19-04-020?
- e. Should the Commission develop a method to streamline safety performance metrics development and reporting across proceedings? If so, what methods should be considered?
- f. Should the Commission adopt quality of service and management metrics for PG&E in this proceeding?

5. Clarifying Guidance on “Controls” and “Mitigations”

The Scoping Memo asks whether there is a need to further define the terms “mitigations” and “controls” or to clarify the methodologies used to implement these terms in the RDF. An essential element of the SA Decision is the requirement for utilities to provide RSE calculations for all mitigations included in RAMP applications. Since RSE scores are used in ranking and selecting proposed RAMP mitigation options, they are an integral part of RAMP applications. Appendix A of the Staff Proposal, issued on June 4, 2021, included SPD Staff’s Recommendations on Phase I Track 1 (Staff Track 1 Recommendations).

This section discusses the background to the Track 1 issue of the need to define or clarify methodologies associated with “mitigations” and “controls,” introduces Staff’s proposal, and reviews party comment. We conclude by clarifying guidance on use of the terms “mitigations” and “controls” in the RDF and related RAMP filings. We direct the IOUs to each, and as a group, consistently and uniformly define and treat all forms of mitigations including

control measures in their RDFs and RAMP filings, and in other related filings in other proceedings. We direct the IOUs to work together to come up with uniform working definitions of controls (and also, if needed, mitigations) that are consistent and compliant with the 2021 Revised S-MAP Lexicon definitions we adopt in this decision.

We direct the IOUs to evaluate all mitigations for efficacy and efficiency when using the RDFs and in their RAMP filings, whether the mitigation is “in process” or newly proposed. We clarify that the IOUs are required to calculate RSEs for all mitigations, including controls that are ongoing. We adopt a specific approach to establishing baselines for mitigations and controls and require the IOUs to begin using this starting January 2022.

5.1 Background

The Interim Decision and the SA Decision together defined key terms in utility risk modeling and mitigation assessment, producing the 2018 S-MAP Revised Lexicon adopted in the SA Decision. The 2018 S-MAP Revised Lexicon defines both “controls” and “mitigations.” The SA Decision requires RSE calculations for all “mitigations.”

The term “control” was first defined in the Interim Decision as a “[c]urrently established measure that is modifying risk”⁶ and the SA Decision retains this definition. The SA Decision defines “mitigation” as “a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event” and retains the definition of “control” adopted in the Interim Decision.⁷ The SA Decision requires the

⁶ Interim Decision at 25.

⁷ SA Decision at 16-17.

calculation of pre- and post-mitigation risks for all mitigation measures and requires IOUs to include in their RAMP applications a description of “controls” or “mitigations” currently in place, as a “baseline for understanding how safety mitigation improves over time.”⁸

As discussed in the Staff Track 1 Recommendations, the IOUs have in their RAMP applications used a variety of methods to distinguish measures that are “currently established” or “in place” from those that are new.⁹ Specifically, the IOUs independently developed a variety of approaches to the concept of “controls;” SCE, for instance, defined a subcategory of controls it calls “compliance controls.”¹⁰ Further, the IOUs have applied different treatments to mitigations and controls as they have defined them. For instance, Staff note that PG&E did not calculate RSEs for all “controls” currently in place in its 2020 RAMP application, even though PG&E indicated it primarily reduces risk through controls.¹¹

5.2 Staff Proposal

Staff observes that a “control,” (“currently established measure that is modifying risk”), if it is “in process” and “designed to reduce the impact/consequence and/or likelihood/probability of an event,” is a “mitigation.” Further, Staff notes that the SA Decision requires that RSEs be calculated for all mitigations, including controls that are mitigations because they are “in progress.” Therefore, the Staff Proposal does not recommend that the

⁸ SA Decision at Attachment A, 33.

⁹ Staff Track 1 Recommendations at 4 – 6.

¹⁰ SCE 2018 RAMP report, filed in I.18-11-006, and available as of November 2, 2021 at <https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics>.

¹¹ *Id.* at 6. PG&E did provide this information in its 2020 GRC filing, however.

Commission update the adopted definitions for “controls” and “mitigations.” However, the Staff Proposal does recommend that utilities be required to consistently define and treat controls and mitigation measures in their filings across various Commission proceedings, including any and all subcategories of controls. Specifically, Staff recommend that the IOUs be required to uniformly apply methodologies and definitions to establish risk baselines associated with mitigation measures in their RAMP applications and other relevant RDF filings.

To prevent potential errors and inconsistent treatment in evaluating risks across utilities, Staff recommends that utilities adhere to the following requirements when developing risk scores and RSEs for mitigation measures, whether these are controls or newly proposed mitigations:

- Type A Baseline Measures: For all controls and mitigation measures and/or activities that a utility plans to implement prior to the beginning of the upcoming GRC test-year, the utility accounts for all actual and forecasted risk reduction benefits in the baseline associated with those measures and/or activities that have been approved in the prior and/or current GRC cycles.
- Type B Baseline Measures: Account for all actual and forecasted risk reduction benefits in the baseline associated with all controls and mitigation measures and/or activities that have not been funded by ratepayers and/or exceed the original approved scope and/or funding in the prior and/or current GRC cycles. In other words, incremental costs (above what was approved for funding in prior GRCs) associated with these measures are excluded from the RSE calculations; however, the utility should account for risk reduction benefits associated with these measures.
- Type C Baseline Measures: Exclude from the baseline forecasted risk reduction benefits for all mitigation measures and/or activities (that have been approved in the prior and/or current GRC cycles), which the utility does

not plan to implement prior to the beginning of the upcoming GRC test-year.

- The utility should identify in its annual RSAR the costs for controls and/or mitigation measures and/or activities that were approved in prior GRC cycles but not implemented, as applicable.¹²

Staff also recommends that the Commission consider examining how risk profiling and mapping utilizing tools such as digital mapping or geographic information systems (GIS) could be incorporated into future RAMP filings to further improve transparency and accountability in Phase II of this proceeding.¹³

5.3 Party Comments

Parties generally support requiring the IOUs to use a uniform approach to identify baselines for mitigations and controls, as proposed by Staff. However, TURN recommends consolidating Type A and Type B measures to account for all actual and forecasted risk reduction benefits in the baseline associated with all controls and mitigation measures and/or activities to be performed before the GRC test year, whether or not those activities were previously authorized or exceed authorized funding levels, stating that distinguishing between these two types is not necessary. UCAN stresses that all IOUs must define “mitigations” and “controls” in a common manner to provide transparency. UCAN also requests clarification on the definition of “incremental costs.” PCF recommends that Staff’s recommendation is modified to add the sentence, “The terms ‘baseline,’ ‘control’ and ‘mitigation’ may not be interpreted or used in an effort to avoid RSE calculations, which remain required for all risk reduction activities,” and to point to 2014 as the base year to establish risk baselines. PCF also asserts

¹² *Id.* at 10-11.

¹³ *Id.* at 11.

the word “approved” in Staff’s definition of Type A baselines is confusing and must be understood as the dictionary definition of the term.

SDG&E/SoCalGas recommend the Commission consider correctly defining baselines for mitigations and controls in Track 3 given that the baseline measures proposed by Staff in Track 1 reference GRCs and RSARs and may result in changes to the time period utilities present cost and risk reduction benefit estimates in RAMP submissions. TURN disagrees with SDG&E/SoCalGas and observes that the SA Decision states that utility RDFs must take into account the benefits of any mitigations that are expected to be implemented prior to the GRC period under review in the RAMP submission and those benefits should be based on data supplemented by subject matter expert (SME) judgment to determine those benefits.

PG&E asserts that the Staff proposal requires use of “inherent risk” because it excludes any level of activity in test year. PG&E states that the SA Decision defines inherent risk as risk that excludes any controls or mitigations. To address this, PG&E proposes a fourth category of baselines, Type D, which PG&E states allows for the baseline risk score to include the existing level of mitigations and controls and allows for the calculation of RSEs for programs that are included in the baseline. PG&E proposes that Type D baselines measures include “in the baseline forecasted risk reduction benefits for all mitigation measures and/or activities (that have been approved in the prior and/or current GRC cycles), at previously established and/or authorized levels, that utilities intend or are required to continue into the new GRC cycle. Utilities are not precluded from calculating RSEs for programs as required by the Settlement

Agreement solely on the basis of such programs being identified herein.”¹⁴

TURN opposes PG&E’s proposed Type D baselines as unnecessary and a misinterpretation of the SA Decision.

5.4 Discussion

We adopt Staff’s proposal regarding mitigations, controls and baselines, with modifications. We direct the IOUs to evaluate all mitigations for efficacy and efficiency when using the RDFs and in their RAMP filings, whether the mitigation is “in process” or newly proposed. We direct the IOUs, individually and as a group, to consistently define and treat controls and mitigation measures in their filings across various Commission proceedings, including all subcategories of controls. We direct the IOUs, individually and as a group, to uniformly apply working definitions of controls, including all subcategories of controls, and uniformly apply methodologies to establish risk baselines associated with mitigation measures in their RAMP applications and other relevant RDF filings. We direct the IOUs to work together to come up with uniform working definitions of all subcategories of controls (and also, if needed, mitigations) that are consistent and compliant with the 2021 Revised S-MAP Lexicon we adopt in this decision. This consistency will allow for comparison of filings across utilities and across various proceedings.

We do not modify the overarching definitions of “controls” and “mitigations” adopted previously, as this is not necessary with the additional guidance provided here. As noted in the Staff Proposal, we clarify that RSEs should be calculated for all mitigations, regardless of whether the mitigation is also a control.

¹⁴ PG&E Opening Comments at 4.

We adopt a modified version of Staff's proposed requirements for establishing baselines that includes TURN's recommendation to consolidate Type A and Type B measures and includes other changes to improve clarity. We add the terms "baseline" and "baseline risk" to the 2018 S-MAP Revised Lexicon to create a 2021 S-MAP Revised Lexicon, attached as Appendix D. The adopted proposal is as follows:

The baseline is a reference point in time at the start of the new GRC cycle. The baseline risk as applied to RAMP and GRC proceedings refers to the amount of residual risk evaluated at the baseline (*i.e.* at the start of the new GRC cycle) after taking into account all risk reduction benefits from all risk mitigation activities projected to have been performed by the start of the new GRC cycle. The projected risk mitigation activities include those that are classified by the IOUs as controls, as well as all mitigation activities for which the IOUs are seeking approval and/or funding in the current or upcoming RAMP and GRC applications.

For clarity, we also slightly revise the definition of "residual risk" included in the 2018 S-MAP Revised Lexicon as "risk remaining after ~~current controls~~ application of mitigations, including mitigations classified as controls." This revision is included in the 2021 S-MAP Revised Lexicon in Appendix D. To smooth transition to these new definitions, we clarify that in case of conflict with other usages of these terms, the revised or new definitions supersede those other usages and definitions. The definitions and transition approach we adopt are reasonable and practicable.

In addition, as proposed in the Staff Proposal, we direct each IOU to identify in its annual RSAR the costs for controls and/or mitigation measures and/or activities that were approved in prior GRC cycles but not implemented, as applicable. Requiring the IOUs to use consistent methods to define and

establish baselines for mitigations and controls in their RDFs, RAMP filings, and across other relevant proceedings will help avoid inconsistent evaluation of risks across utilities and proceedings.

We agree with the recommendation in the Staff Proposal to defer the examination of how risk profiling and mapping utilizing tools such as digital mapping or GIS can be incorporated into future RAMP filings to Phase II of this proceeding.¹⁵

6. Treatment of Foundational Programs & Activities

The Scoping Memo asks how “foundational programs or activities” such as technological tools for data gathering should be estimated or measured in the RDF.¹⁶ The SA Decision does not define “foundational programs or activities.”

Examples of foundational programs or activities may include software and computer hardware resources, situational awareness initiatives such as weather modeling, and vehicles used by employees. This type of initiative supports or enables utility mitigation programs and/or improves utility operations but does not generally directly reduce safety risks.

In this section we define foundational programs and/or activities as “initiatives that support or enable two or more mitigation programs or two or more risks but do not directly reduce the consequences or the likelihood of risk events.” We direct the IOUs to include the costs of foundational programs and/or activities in RSE calculations for the mitigation programs the foundational elements support if the foundational element costs exceed the thresholds adopted for the RSARs in D.19-04-020. We also authorize the IOUs to

¹⁵ *Id.* at 11.

¹⁶ Scoping Memo, Issue (d.) at 5.

include foundational program and/or activity costs below the RSAR thresholds in their mitigation program RSEs on an optional basis.

6.1 Staff Proposal

The Staff Proposal recommends that the Commission define “foundational programs or activities” as “initiatives that support multiple mitigation programs but do not directly reduce the consequences or reduce the likelihood of risk events.”¹⁷ Staff suggests that the Commission consider adding this definition to the 2018 S-MAP Revised Lexicon.

The Staff Proposal recommends that the Commission not require utilities to produce risk reduction scores or RSEs linked solely to foundational programs. Instead, the Staff Proposal recommends the Commission clarify expectations when it adopts a definition of foundational programs by providing direction on how IOUs should treat the costs of foundational programs or activities in the RDF.

The Staff Proposal recommends that foundational activities and costs be subject to a threshold test and exclude “sunk costs” (for which the utility either has received cost recovery or does not seek cost recovery) from the threshold test. For foundational activities that meet the conditions set for the threshold test, Staff recommend that costs be apportioned to the corresponding mitigations.

6.2 Party Comments

TURN and UCAN recommend the Commission adopt a process to categorize activities as foundational elements. TURN recommends that the first step of this process should be an informational filing by the IOUs listing all

¹⁷ Staff Track 1 Recommendations at 15.

programs they would define as foundational alongside the budget for these programs. This information can be used to identify the types of programs considered foundational by the IOUs and also to determine the typical budget of a foundational program. If in general these programs tend to be relatively low budget projects, it may not be necessary to score every one of these projects. Alternatively, a breakdown of the budgets could demonstrate that there is a clear threshold in a budget over which projects should be scored. TURN states that additional discussion of the meaning of “directly reduce” is needed and could be clarified through examination of the proposed foundational programs.

PCF proposes that the Commission modify the definition of “foundational” in two ways: “foundational programs” should be explicitly set forth on a published list and “foundational programs,” like all other risk reduction activities, must adhere to RSE requirements.

PG&E and TURN recommend the Commission adopt variations on a “multi-portfolio” approach to reflect foundational costs in mitigation RSEs. PG&E recommends the Commission require a single portfolio RSE score, defined as the total risk reduction of all enabled mitigations, divided by the costs of all the enabled mitigations and the foundational programs. TURN disagrees and instead recommends that the Commission require the utilities to calculate all potential combinations of foundational programs and all potential cost apportionments across the entire portfolio of mitigations.

SDG&E/SoCalGas agree with Staff that a cost threshold is necessary but state that costs should be apportioned based on IOU SME judgement, rather than as recommended by Staff or other parties.

6.3 Discussion

We adopt Staff's proposed definition of foundational programs and/or activities, with modifications. We define foundational programs/activities as "initiatives that support or enable two or more mitigation programs or two or more risks but do not directly reduce the consequences or reduce the likelihood of safety risk events." We add this term and definition to the 2021 S-MAP Revised Lexicon included in Appendix D.

We direct the IOUs to include the costs of foundational program activities in the RSE calculations for the mitigation programs that they support or enable if these exceed the thresholds adopted for the RSARs in D.19-04-020, which we describe below. We also authorize the IOUs to include foundational program and activity costs below the RSAR thresholds in their mitigation program RSEs on an optional basis.

We direct each IOU to incorporate costs of foundational elements into the RSEs they present in their next RAMP filing. In doing so, the IOUs shall clearly and transparently explain and justify their chosen distribution of foundational costs to mitigations and must comply with applicable requirements of the SA Decision and explain their rationale and assumptions in categorizing the foundational elements as described in line 29 of the Settlement Agreement.¹⁸ We

¹⁸ Line 29 of the Appendix A to the SA Decision states "Inputs and computations for the Steps described in this document should be clearly stated and defined in RAMP and, when applicable, the GRC. The sources of inputs should be clearly specified. When SME judgment is used, the process that the SMEs undertook to provide their judgment should be described. Any questionnaire or document used to solicit SME judgment will be made available to the CPUC and parties upon request. The utility should specify all information and assumptions that are used to determine both pre- and post-mitigation risk scores. The methodologies used by the utility should be mathematically correct and logically sound. The mathematical structure should be transparent. All algorithms should be identified. All calculations should be repeatable by third parties using utility data and assumptions recognizing that, dependent on

Footnote continued on next page.

may consider and adopt additional refinements and guidelines to our direction here in subsequent decisions.

Requiring the IOUs to use the cost and percentage thresholds adopted for the RSARs to include foundational costs in their RSEs is reasonable and provides for both consistency and appropriate variation based on company size.

Adopting this approach now will add clarity to future RAMP filings while also allowing more time to consider additional approaches that may be appropriate, such as the “multi-portfolio” approach suggested by TURN, which we discuss further below.

In D.19-04-020, we adopted varying minimum dollar thresholds for RSARs based on the relative size of each IOU.¹⁹ A similar approach is appropriate here because the threshold levels have an objective basis and applying them has been feasible and useful in the RSAR context and will also be so here. We adopt the following:

- PG&E and SCE shall include the cost of foundational programs in RSE calculations if the aggregate cost over the upcoming GRC funding period of the foundational programs supporting a portfolio of risk mitigations exceeds the lesser of \$10 million, or 20 percent of the cost of the portfolio of enabled mitigations, subject to a minimum of \$5 million for the percentage test;
- SDG&E shall include the cost of foundational programs for its electric operations in RSE calculations if the aggregate

the models used, some variation of result may occur. This requirement is subject to practicality and feasibility constraints of sharing data and models (such as confidentiality, critical energy infrastructure data, volume of information and proprietary models). If these constraints arise, the utility will walk through the calculations in detail when requested by intervenors or the CPUC Staff.”

¹⁹ D.19-04-020 at 43, Table 4.

- cost over the upcoming GRC funding period of the foundational programs supporting a portfolio of risk mitigations exceeds the lesser of \$5 million, or 20 percent of the cost of the portfolio of enabled mitigations, subject to a minimum of \$2.5 million for the percentage test;
- SDG&E shall include the cost of foundational programs for its gas operations in RSE calculations if the aggregate cost over the upcoming GRC funding period of the foundational programs supporting a portfolio of risk mitigations exceeds the lesser of \$2.5 million, or 20 percent of the cost of the portfolio of enabled mitigations, subject to a minimum of \$0.5 million for the percentage test; and,
 - SoCalGas shall include the cost of foundational programs in RSE calculations if the aggregate incremental cost over the upcoming GRC funding period of the foundational programs supporting a portfolio of risk mitigations exceeds the lesser of \$5 million, or 20 percent of the cost of the portfolio of enabled mitigations, subject to a minimum of \$1 million for the percentage test.

TURN's suggested "multi-portfolio" approach would require the IOUs to consider every possible combination of allocating foundational costs to mitigation RSEs, under the assumption that some mitigations will not be approved. TURN's approach could help bring clarity to this issue as it would consider all possible outcomes of the allocation of foundational costs, including where a mitigation to which costs had been allocated is not ultimately adopted.

As described in more detail in section 12, this decision formalizes a Technical Working Group (TWG) for R.20-07-013. The TWG will address RDF Proceeding issues as directed here and in Sections 7.3, 8.3, 9.1.4, 9.2.2, and 10.4.2

of this decision.²⁰ As part of its work, we encourage the TWG to identify potential opportunities to test TURN's suggested approach using a small number of use-cases to understand the scope of work involved and allow for an assessment of the quality of the results.

Some of the unanswered questions that could be explored by the TWG in a test of TURN's suggested approach include:

- How should the IOUs apply the different RSEs from the different combinations of mitigations and associated foundational activities into a logical decision-making framework to justify the selection of mitigations and foundational activities presented in the RAMP applications?
- How should the IOUs incorporate consideration of alternative mitigations and alternative foundational activities into the decision-making framework when foundational activities are involved?
- Should a reporting template be developed to ensure uniform treatment and uniform reporting of foundational activities and the associated RSEs?

We do not require the IOUs to develop lists of foundational programs and activities as suggested by TURN. The IOUs may have varying types of foundational activities depending on the risks and mitigation programs included in their respective RAMP filings, and it is important that the IOUs retain the flexibility to update the types of foundational activities they undertake as new operational needs or circumstances arise. A formal list would hinder that ability.

²⁰ The Commission in D.16-08-018, Ordering Paragraph 11, established a S-MAP TWG led by Safety and Enforcement Division Staff to discuss issues raised in A.15-05-002, the S-MAP Proceeding.

7. Requiring Modeling of PSPS Events as Risk Events

The Scoping Memo asks how PSPS events and other utility activities with high customer impacts should be treated in the RDF.²¹ Our consideration of whether and to what extent PSPS events should be addressed in this proceeding takes into account that the Commission provides guidance on PSPS events in two other rulemaking proceedings.

Wildfire Mitigation Plans (WMPs) required in Section 8386 are considered by the Commission in R.18-10-007. The Office of Energy Infrastructure Safety (OEIS) WMP Guidelines require that utilities detail the methodology they use to model risks and impacts associated with PSPS events.²² The OEIS WMP Guidelines require utilities to “include[e] a list of all inputs used in impact simulation; data selection and treatment methodologies; assumptions, including SME input; equation(s), functions, or other algorithms used to obtain output; output type(s), *e.g.*, wind speed model; and comments.”²³ The OEIS WMP Guidelines ensure transparency but do not require the utilities to use a specific methodology to model PSPS risks. The OEIS WMP Guidelines also require utilities to show how they plan to reduce the probability and impact of PSPS events on the public.

In R.18-12-005 *Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions*, the Commission adopted a series of decisions implementing PSPS Guidelines and the proceeding remains open to consider the potential development of additional or modified guidelines.

²¹ Scoping Memo, Issue (b) at 4.

²² On July 1, 2021 the Wildfire Safety Division (WSD) become OEIS.

²³ Resolution WSD-011, Attachment 2.2 - 2021 OEIS WMP Guidelines Template at 27.

7.1 Staff Proposal

When considering whether and how the Commission should provide guidance on treatment of PSPS events in the RDF, Staff closely examined SDG&E's 2021 WMP and RAMP filings. SDG&E's 2021 WMP risk assessment includes separate risk scores for both wildfire risk and PSPS impacts.²⁴ SDG&E's 2021 RAMP models PSPS as a risk impacting the overall total wildfire risk score, as well as a mitigation to wildfire risk.²⁵

Staff recommends that the IOUs be required to assess impacts and risks associated with PSPS events in their RAMP filings. This is consistent with ongoing Commission proceedings that address and acknowledge the safety risks and impacts associated with PSPS events and would further Commission requirements that utilities identify the safety risks and impacts associated with PSPS events. However, Staff also recommend the Commission defer providing any additional specific guidance on treatment of PSPS events until Phase II of this proceeding, stating that additional review of utility methodologies to model PSPS events in WMPs and RAMPs is necessary.

7.2 Party Comments

In opening and reply comments, parties generally agreed that it would be premature to include any prescriptive requirements in this decision. However, they had varied suggestions for next steps on policy and process.

Cal Advocates states that the Track 1 working group should begin the process of identifying approaches to assessing PSPS customer harms now and Phase II of the proceeding should adopt an approach for how the utilities should

²⁴ Staff Track 1 Recommendations at 16; SDG&E 2021 WMP Plan Update at 28-29.

²⁵ See SDG&E RAMP, available as of August 23, 2020 at: <https://www.sdge.com/proceedings/2021-sdge-ramp-report>.

assess the safety, financial, and economic harms from PSPS events so that these can be incorporated into future utility RAMP filings. SCE asserts that operational decision making about use of PSPS events is outside the scope of this proceeding, but that Phase II could consider PSPS risks versus wildfire risks.

MGRA asserts that data on PSPS events may become less available as a result of the PSPS Guidelines adopted in D.21-06-034²⁶, thus the Commission should undertake a more thorough vetting of PSPS guidelines and metrics in this and RAMP proceedings. Specifically, MGRA is concerned that D.21-06-034 requires utilities to submit data on the thresholds used for PSPS initiation, the duration of PSPS events, and the scope of PSPS events not in utilities' "post-event reports" but, rather, annually in "post-season" reports.

7.3 Discussion

We require the IOUs to treat PSPS events as a risk within the RDF framework, not just as a mitigation, just as they would for any other risk to safety, reliability, and finances. Similar to other risks, the IOUs shall address the likelihood and consequences of PSPS events in the RDF and in future RAMP filings.

OEIS WMP Guidelines already require analysis of PSPS impacts, and the IOUs have already started to model PSPS risks and consequences in their WMPs and, for SDG&E and SoCalGas, in their RAMPs. SCE, which will be filing its next RAMP in May 2022, modeled the probability and consequences of both wildfire and PSPS events in its 2020 WMP.²⁷ For example, SCE's 2020 WMP

²⁶ This decision was issued in R.18-12-005 and adopted PSPS Guidelines and rules for utilities.

²⁷ Southern California Edison 2020-2022 Wildfire Mitigation Plan. Available as of August 25, 2021 here: <https://www.sce.com/sites/default/files/AEM/SCE%202020-2022%20Wildfire%20Mitigation%20Plan.pdf>.

estimated the probability of PSPS events using a 10 year back-cast based on wind and weather data, estimated the number of customers who may be impacted and converted it to a safety index. In addition, SCE utilizes \$250 per customer, per de-energization event to approximate potential financial losses on average, recognizing that some customers may experience lower (or zero) financial impacts, while other customers' claimed losses may exceed \$250.

Although we do not adopt additional guidance on how the IOUs should treat PSPS events as risks in the RDF at this time, requiring the IOUs more generally to include PSPS risks and consequences in the RDF will help us better consider the customer impacts of PSPS events going forward. For now, treatment of PSPS in the RDF shall be subject to D.18-12-014 provisions requiring inputs and calculations for each step of the analysis to be "clearly stated and defined," while "[t]he sources of inputs should be clearly specified" when SME judgment is used, and "the process the SMEs undertook to provide their judgment should be described" and the utility "should specify all information and assumptions that are used to determine pre- and post-mitigation risk scores."²⁸

The Track 1 working group in this proceeding has been discussing potential methods for the IOUs to quantify safety impacts on customers from PSPS events to improve how PSPS events as risk events are modeled in the RDF. Staff and parties should continue to discuss questions surrounding modeling of PSPS events in the RDF as part of ongoing Track 1 TWG discussions. If Staff and/or parties develop a proposal to consider providing more detailed Commission guidance on this topic, the Assigned ALJ or Commissioner will

²⁸ D.18-12-014, Appendix A, at A-17.

provide an opportunity for party comment and consideration in a future decision in this proceeding.

8. Deferring Action on Best Practices for Modeling Wildfire Risk

The Scoping Memo asks if the Commission can and should identify any guiding principles, best practices, aspirational characteristics, and/or minimum requirements for developing an RDF MAVF?²⁹ An MAVF is a tool to combine all of the potential consequences of the occurrence of a risk event and express these as a single value.³⁰ The SA Decision requires that utilities develop an MAVF to assess the consequences of a risk event based on six principles:³¹

1. Attribute Hierarchy
2. Measured Observations
3. Comparison
4. Risk Assessment
5. Scaled Units
6. Relative Importance

A utility may adjust its MAVF over time if it adheres to the six principles. The fourth principle regarding risk assessment allows utilities to “assess uncertainty in the Attribute levels by using expected value or percentiles, or by specifying well-defined probability distributions from which expected values and tail values can be determined.”³² Thus, utilities may select the modeling methods they prefer to model the consequences of wildfire risks as long as the method meets the threshold of comprising a “well-defined probability

²⁹ Scoping Memo, Issue (c.) at 4.

³⁰ D.18-12-014 at 17.

³¹ D.18-12-014, Appendix A.

³² D.18-12-014, Appendix A.

distribution.” However, MGRA has consistently highlighted the merits of using a “power law probability distribution” to model wildfire consequences, a requirement that would be more specific than the existing requirement.³³

During Track 1 working group sessions, Staff and parties discussed whether the SA Decision approach allowing a utility the flexibility to select its own wildfire risk modeling approach remains appropriate or whether the power law probability distribution method is superior and should be required or identified as a best practice.³⁴ A distinguishing feature of wildfire size (and consequence) following power law behavior is that extreme events dominate the results, which is consistent with the recent California wildfires of historical proportions.³⁵

8.1 Staff Proposal

Staff recommend the Commission defer action requiring or recommending use of the power law probability distribution as an MAVF best practice at this time. Staff recommend that the topic be further discussed in Phase II of this proceeding.³⁶

Staff indicate that they and parties made significant progress discussing the appropriateness of utilities consistently using the power law probability distribution method to model wildfires in their RDFs. Staff state they will continue to work informally with parties to identify guiding principles, best

³³ MGRA, Comments on RDF OIR; MGRA, Protest in Proceeding A.20-06-012, July 29, 2020.

³⁴ MGRA White Paper, *Wildfire Statistics and the Use of Power Laws for Power Line Fire Prevention*, (MGRA White Paper) February 11, 2021 was attached as Appendix A to MGRA’s Comments Regarding Development of Safety and Operational Metrics filed March 1, 2021, available as of August 23, 2021 at: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M368/K055/368055506.PDF>.

³⁵ Staff Track 1 Recommendations at 19-22.

³⁶ *Id.* at 21.

practices, aspirational characteristics, and minimum requirements to improve future RAMP requirements. Staff recommend that utilities and parties continue to collaborate to validate different methodologies that appropriately estimate the risk of extreme events to capture maximum loss, consistent with wildfire risk behavior. Consistent with this, Staff indicate that PG&E intends to use the power law distribution function to model wildfire risk consequences and intends to share its findings with the Track 1 working group in September 2021. Staff observe that the SA Decision provides that Staff and parties can request a utility to present a power law-related scenario analysis in response to a RAMP data request.

8.2 Party Comments

While parties generally support Staff's proposal, Cal Advocates and MGRA recommend that the Commission explicitly provide for further exploration of the applicability of the power law distribution to model wildfire risk in Phase II of this proceeding, alongside other potential approaches. These parties state that PG&E's planned test drive of the power law distribution should provide a basis for this further discussion and exploration, with the goal of identifying and adopting an approach for modeling wildfire risk and consequences that properly captures increasing wildfire risk due to climate change.

MGRA states that "MAVF functions for wildfire risks, regardless of the functional form adopted, will be dominated by extreme outlier events, so any methodology that caps losses or otherwise fails to incorporate or predict extreme loss events will be an inaccurate representation of risk."³⁷ MGRA emphasizes

³⁷ MGRA, *Comments on Staff Proposal* at 7.

that “consequences for wildfire must sufficiently incorporate high-end losses.”³⁸ MGRA also requests that the Commission clarify that the SA Decision requires IOUs to undertake and provide a sensitivity analysis of risks modeled in the RDF when requested.

UCAN recommends that the Commission require the IOUs to more accurately reflect the location of customer assets when conducting wildfire modeling and framing inputs used in the MAVF.

8.3 Discussion

We adopt Staff’s proposal and defer requiring or recommending use of the power law probability distribution as an MAVF best practice at this time. We direct Staff to continue to monitor this issue in their reviews of IOU RAMP filings and, if and when appropriate, to work with the TWG to provide a follow up recommendation on this topic as early as Phase II of this proceeding, if feasible. TWG discussions in this area shall include UCAN’s suggestion regarding more accurate modeling of the location of customer assets in wildfire models.

We agree with MGRA that it is essential that the modeling method used by IOUs in their RDFs, WMPs, and RAMPs produces a set of consequences for wildfire that sufficiently incorporate high-end losses. However, it is premature for us to determine that the power law modeling approach is the only method to accomplish this. We will continue to examine this issue in Phase II as part of exploring better ways for climate change risks, impacts, and uncertainties to be reflected in the RDF.

³⁸ MGRA, Reply Comments on Staff Proposal at 2.

As noted by MGRA, the SA Decision requires IOUs to undertake and provide a sensitivity analysis of risks modeled in the RDF when requested.³⁹

9 Related Clarifications

The Scoping Memo provides for consideration of additional clarifications within Track 1. In working group discussions, Staff and parties identified two additional issues for consideration in Track 1 – the issue of data transparency and consideration of climate change impacts within the RDF.

This section reviews Staff and party work on these topics. Regarding data transparency, we direct SCE to “test drive” PG&E’s Transparency Proposal and to serve the completed transparency documents to the SCE 2022 RAMP proceeding service list no later than 60 days after SCE files its 2022 RAMP report.

Regarding consideration of climate change impacts, risks, and mitigation measures, we agree with Staff that this is a topic worthy of consideration in Phase II of this proceeding. However, Phase II of this proceeding already includes a long list of potential issues. Therefore, we direct Staff and parties active in the TWG to prepare and propose an updated “S-MAP Roadmap” and work plan that can be considered to guide Phase II work.

9.1 Transparency in RAMP Filings

Transparency in RDF filings refers to the inclusion of sufficient documentation in RAMP and other IOU filings for parties and Staff to understand methodologies, the quality of data, and any assumptions used.⁴⁰ The need for greater transparency in RDF filings was first suggested by TURN in their opening comments on the OIR and during the December 15, 2020 Track 1

³⁹ D.18-12-014, Appendix A at A-17.

⁴⁰ RDF filings refer to all IOUs filings related to the RDF proceedings, including RAMP applications, RSARs, and GRC filings associated with RAMP.

workshop. Staff and parties further discussed the topic at the March 3, 2021 and March 10, 2021 working group meetings.

At the March 10, 2021 working group meeting, TURN presented its perspective on key features that a transparent RDF process should possess, namely:

- Repeatability of results: IOUs should provide information sufficient that a stakeholder can repeat the calculations and arrive at roughly the same result.
- Uncertainty is an important piece of information that should be presented. IOUs should identify, describe, and, if possible, quantify the uncertainty of the assumptions or estimates; and
- Risk analysis should be sufficiently granular.⁴¹

TURN suggested a streamlined matrix format for reporting risk model assumptions, uncertainties, and annual estimates of pre-mitigation and post-mitigation likelihoods, consequences, mitigation costs, and RSEs.⁴²

At the March 10, 2021 Track 1 working group meeting, PG&E volunteered to develop an initial proposal on transparency guidelines and to engage with working group members to develop the proposal. The working group discussed PG&E's proposal at a meeting on April 14, 2021, and parties provided informal written feedback. On April 23, 2021 PG&E distributed an amended Transparency Guidelines Proposal (PG&E Proposal or PG&E Transparency Proposal) and standardized risk reporting templates to working group members.⁴³

⁴¹ TURN's Transparency of Estimates and Assumption Presentation, March 10, 2021 Track 1 working group meeting.

⁴² Staff Track 1 Recommendations at 29.

⁴³ *Ibid.*

The Assigned ALJ's June 4, 2021 ruling requested party comment on the PG&E Proposal, which was appended to the Staff Proposal as Appendix E.

9.1.1 PG&E Transparency Proposal

The PG&E Proposal recommends two new elements for inclusion in future RAMP reports to address data transparency and uncertainties. The first element is a set of standard workpaper templates and the second is a set of criteria for assessing the quality of data estimates used in the RAMP.

PG&E proposes a standard set of templates for workpapers to be used for all RAMP applications, which PG&E states could streamline the review process but would not preclude parties from making additional ad-hoc requests. PG&E states that the templates support standard formats to provide input data, output calculations, and the associated risk models for each risk assessed in a RAMP application.

PG&E also proposes a set of criteria to categorize the quality of each estimate used in the RDF instead of reporting a numerical uncertainty value. PG&E calls these "estimate quality criteria." PG&E proposes that utilities rate estimates as "High," "Medium," or "Low" quality, to help inform parties of the degree of certainty in the calculations. Calculations of residual risk and risk reduction from proposed mitigation measures typically require estimates and/or assumptions of risk, which introduce uncertainties that can compound through the model.⁴⁴

9.1.2 Staff Recommendation

The Staff Proposal recommends that PG&E's proposal be both modified and tested prior to formal adoption by the Commission. Specifically, Staff

⁴⁴ *Id.* at 32.

recommend that the Commission require SCE to “test drive” the PG&E Proposal as modified by Staff’s suggestions concurrent with SCE’s 2022 RAMP filing.⁴⁵

In discussing PG&E’s proposal, Staff observe that TURN suggests a slightly different format for reporting assumptions used by utilities to estimate risk reduction benefits and the overall quality of data contained in a RAMP filing. The Staff Proposal states that TURN recommends that utilities explicitly identify the discount rate used, the time horizon for each mitigation to indicate how the level of an attribute changes over time in the presence of a mitigation, and that utilities quantify uncertainties in attribute levels with probability distributions, annually if necessary.⁴⁶

The Staff Proposal provides additional detailed review of the differences between PG&E’s Proposal and TURN’s recommendations but concludes that, although TURN raises some valid concerns, “PG&E’s Proposal is more comprehensive than TURN’s suggested format because PG&E’s format contains more categories of information while not omitting any information contained in TURN’s format.”⁴⁷ Staff does not recommend that the PG&E Proposal be modified to incorporate any specific recommendations made by TURN. Staff recommend postponing consideration of several Cal Advocates recommendations until after PG&E’s Proposal has been tested.

Staff discuss a proposal from MGRA to include reporting of risk “confidence interval” values at the upper and lower bounds of a parameter, with the lower bound set at the 10th percentile and the upper bound at the 90th percentile of the

⁴⁵ *Ibid.*

⁴⁶ *Id.* at 33.

⁴⁷ *Id.* at 36.

parameter. Staff recommend that PG&E's proposal be updated to include this MGRA suggestion prior to being tested during SCE's 2022 RAMP application.

9.1.3 Party Comments

Parties raise a number of issues regarding Staff's proposal that SCE test PG&E's proposed Transparency Guidelines, modified as suggested by Staff, concurrent with its 2022 RAMP filing and that the Commission consider adopting the proposal formally at a later date. SCE states that any technical clarifications to the SA Decision must not change the requirements for SCE's next RAMP showing, due May 2022, in any significant manner. SCE states that utilities should not be required to provide "confidence interval" values, as proposed by MGRA and Staff, or an Estimated Quality Table or a Sensitivity Analysis Table, as proposed by PG&E, because these are not current RAMP requirements. SCE and PG&E state that it would be extremely difficult to provide 10th and 90th percentile risk values for parameters, and the utilities should not be required to provide this. Instead, PG&E recommends that the Track 1 working group develop a suitable set of estimate ranges to use in sensitivity calculations.

Cal Advocates recommends that the Commission require additional information and references in the PG&E Proposal to provide greater granularity. These include:

- Add a column to the Risk Results and Risk Sensitivity Analysis Tables to report on and reference metrics used to evaluate risk mitigation effectiveness;
- Add a column to the Risk Results Table to reference SME input;
- Expand the granularity of the risk mitigation rows in the Risk Results and Risk Sensitivity Analysis Tables to report

on and reference risk and mitigation uncertainties for GRC level risk mitigation programs.⁴⁸

MGRA supports the PG&E Proposal, stating that it allows for visual comparison of hundreds of risk components, which would “make each risk directly comparable” using the same format and descriptions, and could be supplemented by more detailed descriptions as proposed in the TURN matrix via data request. MGRA supports Staff’s proposal for presentation of risk estimates at the 10th and 90th percentiles because this allows “unusual behavior at the extreme to be flagged.”⁴⁹ MGRA recommends that the Commission provisionally approve Staff’s recommended approach to allow for testing.

MGRA rejects SCE’s concerns that it be required to test the PG&E Proposal concurrent with its May 2022 RAMP filing. MGRA points out that SCE will have had one year to incorporate the PG&E Proposal, that the transparency showings to date in SDG&E and PG&E’s RAMP filings have been “utterly lacking, in spite of the SA requirements,” that SCE could have proposed its own approach, and that waiting to 2024 to test the PG&E Proposal is “too late.”⁵⁰ Cal Advocates recommends that further updates to these guidelines, including adoption of the elements proposed by Cal Advocates, be part of Phase II of this proceeding.

TURN states that it does not oppose the PG&E Proposal but it “does not believe that the Estimate Quality and Sensitivity Analysis Tables proposed by PG&E are helpful additions to the RAMP” because TURN does not believe that an estimate provided by a SME “is any more or less likely to be accurate than internal data. Additional considerations of the qualifiers, most importantly

⁴⁸ Cal Advocates, Comments on Staff Proposal at 36.

⁴⁹ MGRA, Comments on Staff Proposal at 7.

⁵⁰ MGRA, Reply Comments on Staff Proposal at 8.

whether they provide valuable insight into the risk scores is required.”⁵¹ TURN notes that parties to A.15-05-002 *et al* earlier found it useful and straightforward to report probability distributions at the 10th, 50th, and 90th percentiles as a way to disclose uncertainties.⁵² TURN states that it does not oppose a SCE test drive of the PG&E Proposal but that it may also submit a data request using its own format during the SCE RAMP process.

SDG&E/SoCalGas state that the Commission should not adopt the PG&E Proposal without considering the Risk Quantification Framework included in SDG&E and SoCalGas’s most recent RAMP filing and parties’ feedback on the framework. SDG&E and SoCalGas also object to the use of the term “confidence interval” as not reflecting the common meaning of this term where confidence intervals are computed from observed data, which may not be available, and which may result in overuse of subjective values or “N/A” (not applicable). These companies raise additional detailed concerns about the Estimated Quality and Risk Sensitivity Analysis Tables proposed by PG&E.

9.1.4 Discussion

We note the PG&E Proposal with interest and modify it as recommended by Staff before requiring SCE to test the approach. We direct SCE to serve the completed transparency documents to the SCE 2022 RAMP proceeding service list no later than 60 days from the date of SCE’s 2022 RAMP filing. We modify the Staff Proposal to include more granular specifications for sensitivity analysis and confidence level. The PG&E Proposal modified to reflect these changes is contained in Appendix C. It is reasonable to test the PG&E Proposal with Staff’s

⁵¹ TURN, Comments on Staff Proposal at 12.

⁵² *Id.* at Attachment A, at 3.

proposed modifications to explore if these help increase the transparency of estimate uncertainties and identify unusual behavior at the extremes.

It is also reasonable to require SCE to test drive the PG&E Proposal as modified in this decision close to the date of SCE's 2022 RAMP filing so that the Commission and parties can continue to refine transparency measures beyond those required in the SA Decision in a timely manner. We clarify that by requiring that SCE to test and serve the transparency documents we are directing SCE to complete the templates included in the modified PG&E Proposal to the best of its ability. We do not require SCE to use the completed template information to select their mitigation choices. Instead, we will consider the results of SCE's test drive as purely informational regarding the templates' feasibility and their usefulness in providing transparency for Staff and parties. Further, SPD Staff shall work with SCE to support SCE undertaking this test drive in a way that does not disrupt SCE's 2022 RAMP preparations.

We agree with Staff that Cal Advocates' additional proposals to refine PG&E's Proposal should be considered in future phases of this proceeding, including as early as Phase II, if the test drive we direct here has been conducted and reviewed in that timeframe and doing so is otherwise feasible. We authorize SPD Staff to convene discussions on the PG&E Transparency Proposal as part of the TWG moving forward. As part of this, the TWG should discuss Cal Advocates' proposal and the lessons learned from the Risk Quantification Framework included in SDG&E and SoCalGas's most recent RAMP filing and parties' feedback on the framework. The TWG may also discuss the desirability, and, if so, methods to develop an appropriate set of estimate ranges to use in sensitivity calculations, as suggested by PG&E. We request Staff provide an updated Transparency Proposal

for our consideration during Phase II of this proceeding, or at a later date, as appropriate.

We note the IOUs' concerns regarding Staff's 10th and 90th confidence interval proposal. However, SCE's test drive, and any subsequent tests, will help determine the value and feasibility of this approach, which can then be modified as needed.

9.2 Staff Proposal to Consider Climate Change Impacts in Phase II

The Scoping Memo indicates that Track 1 will consider discrete technical questions, whereas more substantive revisions to the RDF will be considered in Phase II.⁵³ Phase II issues include refining the RDF adopted in the SA Decision, including incorporating uncertainties relating to climate change risk drivers.⁵⁴

Responding to the Scoping Memo's invitation to suggest additional items for discussion in Track 1, the Staff Proposal discusses climate change risks, impacts, and mitigation activities in California and recommends the Commission consider these issues in Phase II of this proceeding. The Staff Proposal recommends the Commission consider refining the RDF to include a framework for assessing risks associated with climate change impacts on customers and utility electric and natural gas infrastructure and operations, and potential mitigation measures.⁵⁵ Staff further recommend that the Commission conduct this work in a manner that complements existing Commission guidance on climate change adaptation adopted in R.18-04-019 *Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change*.

⁵³ Scoping Memo, Issue (f.) at 3.

⁵⁴ Scoping Memo at 8.

⁵⁵ Staff Track 1 Recommendations at 23 – 27.

Specifically, Staff recommend that the Commission consider developing methodologies to identify, quantify, and incorporate uncertainties associated with climate change as a risk driver, and methods to estimate potential risk reductions that could result from implementing mitigation measures. Staff also recommend the Commission consider tracking the effectiveness of utility climate mitigation activities on utility infrastructure. Potential climate change impacts that utility mitigation measures could affect include exposure of pipelines to coastal hazards and humidity leading to corrosion risks, structural damage to pipelines and underground storage tanks due to rise in sea levels and extreme storms, and exposure of electric assets to rising sea-levels, extreme storm events, amongst others.⁵⁶

9.2.1 Party Comments

Parties generally support considering methods to incorporate climate change impacts, climate change mitigation methods and impacts, and uncertainties in the RDF in Phase II of this proceeding. Cal Advocates additionally recommends that the Commission adopt an explicit framework for addressing climate change-driven risks in Phase II that includes explicit guidance for how the IOUs should incorporate climate change projections and climate change-driven uncertainty in the RDF, such as, for example, direction that the IOUs should not rely on historical data to assess climate change-driven risks. Cal Advocates recommends that Phase II assess methodologies for modeling risks to capture the increasing severity and frequency of extreme events with the goal of identifying and requiring the utilities to implement best practices in this regard. Cal Advocates recommends that this assessment of methodologies occur

⁵⁶ *Id.* at 28.

in coordination with ongoing Commission work on climate change, reflected in D.19-10-054 and D.20-08-046. Cal Advocates recommends that the assessment examine methods for incorporating the results of utility climate change vulnerability assessments in the RDF, as applicable, and methods to reflect utility contributions to climate change from their operations in the RDF.

PCF, supported by UCAN, emphasizes the need for the RDF, and the Commission more generally, to consider greenhouse gas (GHG) emissions and climate change impacts from natural gas-related proceedings and activities. PCF suggests a number of clean energy metrics relating to natural gas, discussed further in Section 10.5.6 below.

9.2.2 Discussion

We concur with Staff and parties that the topic of climate change impacts, risks and mitigation measures is worthy of consideration in Phase II of this proceeding. However, Phase II of this proceeding already includes a long list of potential issues in scope. Therefore, we direct Staff and parties participating in the TWG to work to prepare and propose an updated overall “S-MAP Roadmap” and a high-level workplan that indicates priorities and any dependencies for Phase II work and that outlines approximate timelines and deliverables needed to address prioritized items. To the extent possible, this should be a consensus-based document, but non-consensus areas may be indicated as needed.

Staff and parties should aim to complete this work by December 31, 2021, or a later date as directed by the Assigned ALJ. The draft Roadmap may be served and filed as a joint proposal from two or more parties or may be presented to the Assigned ALJ as a Staff proposal. The Assigned ALJ and Commissioner will request party comment on the draft Roadmap, when

developing the Scoping Memo for Phase II, as appropriate. A subsequent decision in Phase II may consider adopting such a roadmap.

10. PG&E Safety and Operational Metrics

Track 2 of this proceeding considers safety and operational performance metrics and their broad application, including developing SOMs for use in conjunction with the EOE Process approved in D.20-05-053 for PG&E.⁵⁷

This section provides background on the EOE Process adopted in D.20-05-053 as it relates to PG&E SOMs. We then review the guidance in the SOMs Ruling and PG&E's and Staff's SOMs proposals. We conclude by adopting Staff's proposed SOMs for PG&E with modifications, some of which reflect PG&E's proposals.

10.1 PG&E Enhanced Oversight and Enforcement Process

In approving PG&E's bankruptcy plan of reorganization, D.20-05-053 establishes an EOE Process for how the Commission will closely monitor PG&E's safety and operational performance. The EOE Process centers around "steps" that are initiated by the Commission if certain defined "triggering events" occur. The steps range from Step 1, which requires PG&E to undertake enhanced reporting and oversight, to Step 6, wherein the Commission may revoke PG&E's authority to operate as a California electric utility.⁵⁸

As shown below, several EOE Process steps include SOMs as criteria for triggering events. If the triggering events occur, the Commission may place PG&E in the indicated EOE Process step. PG&E must then submit and implement a Corrective Action Plan and/or the Commission may take other

⁵⁷ Scoping Memo at 3.

⁵⁸ D.20-05-053, at Appendix A.

prescribed actions. The Commission may invoke the EOE Process if PG&E self-reports triggering events or if the Commission becomes aware of the occurrence of triggering events by other means.

EOE Process Steps that Involve SOMs⁵⁹

- Step 1: Enhanced Reporting, Triggering Event: “PG&E fails to comply with, or has shown insufficient progress toward, any of the metrics... contained within the approved Safety and Operational Metrics.”
- Step 2: Commission Oversight of Management and Operations, Triggering Event: “PG&E fails to comply with electric reliability performance metrics, including standards to be developed for intentional de-energization events (*i.e.* PSPS) and any that may be contained within the approved Safety and Operational Metrics.”
- Step 3: Appointment of Third-Party Monitor, Performance that Results in Exit from Step 3: The Commission, by Resolution, will move PG&E to Step 4 if... “the Commission determines that additional enforcement is necessary because of PG&E’s systemic non-compliance or poor performance with its Safety and Operational Metrics over an extended period.”
- Step 4: Appointment of a Chief Restructuring Officer, Triggering Event: The Commission determines that “[a]dditional enforcement is necessary because of PG&E’s systemic non-compliance or poor performance with its Safety and Operational Metrics over an extended period.”

EOE Process triggering events also include PG&E failure to comply or show sufficient progress with any metrics set forth in:

- WMPs;
- PSPS protocols; and,

⁵⁹ *Id.* at 1, 2, 5.

- Safety Culture Investigation.⁶⁰

Additionally, Step 1 of the EOE Process includes a triggering event that would occur if PG&E demonstrates insufficient progress toward approved safety or risk-driven investments related to the electric and gas business.⁶¹ Step 2 can be triggered if the destruction of a 1,000 or more dwellings is the result of PG&E failing to follow Commission rules or prudent management practices or if PG&E fails to comply with electric reliability performance metrics.⁶² In short, SOMs are an important element of a multi-faceted EOE Process.⁶³

D.20-05-053 describes SOMs as “attainable Safety and Operational Metrics that, if achieved, would ensure that PG&E provides safe, reliable, and affordable service consistent with California’s clean energy goals.”⁶⁴ D.20-05-053 further indicates that the “Commission will consider metrics to measure PG&E’s quality of service and quality of management in the proceeding addressing Safety and Operational Metrics.”⁶⁵

SOMs are also intended to be used by the Commission and PG&E for the purpose of determining executive compensation. D.20-05-053 and OEIS guidance on executive compensation indicates that a “a significant component of

⁶⁰ *Id.* at 1, referencing Step 1 of the EOE Process.

⁶¹ *Id.* at 2.

⁶² *Id.* at 3.

⁶³ The Commission placed PG&E into Step 1 of the EOE Process in April 2021. See *Resolution M-4852: Placing Pacific Gas and Electric Company into Step 1 of the “Enhanced Oversight and Enforcement Process” Adopted in Decision 20-05-053* included the finding that “PG&E has made insufficient progress toward Approved Safety or Risk-Driven Investments Related to Its Electric Business (Enhanced Oversight and Enforcement process Step 1, Triggering Event A(iii)), available as of August 31, 2021 at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M367/K731/367731890.PDF>.

⁶⁴ D.20-05-053 at 38.

⁶⁵ *Id.* at 96.

[PG&E's] long-term incentive compensation" must be based "on safety performance, as measured by a relevant subset of the Safety and Operational Metrics."⁶⁶

The EOE Process does not supplant the Commission's existing regulatory or enforcement authority and does not limit the Commission's ability to pursue other enforcement actions against any regulated utility.⁶⁷ The Commission remains free to pursue all regulatory authority at its disposal, including (but not limited to) those in Resolution M-4846, which adopts the Commission's Enforcement and Penalty Assessment Policy.⁶⁸ The EOE Process does not replace or limit the Commission's regulatory authority, including the authority to issue Orders to Show Cause and Orders Instituting Investigations, and to impose fines and penalties.⁶⁹

10.2 Questions on SOMs in Assigned Commissioner's Rulings

The Scoping Memo asks several questions related to SOMs:

- What safety and operational performance metrics should be developed pursuant to D.20-05-053 addressing PG&E's reorganization plan? What are appropriate criteria for selecting metrics as safety and operational performance

⁶⁶ D.20-05-053, at 88; Wildfire Safety Division Guidance on Submission of Executive Compensation Approval Requests by Electrical Corporations Pursuant to Public Utilities Code 8389(e)(4) and 8389(e)(6) at 3, December 22, 2020, available here as of July 14, 2021: <https://energysafety.ca.gov/wp-content/uploads/docs/misc/wsd/wsd-executive-compensation-guidance-20201222.pdf>.

⁶⁷ D.20-05-053 at 55.

⁶⁸ Resolution M-4846, *Resolution Adopting Commission Enforcement Policy*, available as of September 1, 2021 at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M350/K405/350405017.PDF>.

⁶⁹ D.20-05-053, Appendix A at 1.

metrics? What is the relationship and/or difference between safety metrics and operational metrics?

- Should the safety and operational performance metrics apply to all IOUs? Are there variances regarding how these adopted metrics should be applied to individual IOUs? How should the Commission use adopted safety and operational performance metrics?
- Should the Commission adopt performance criteria or targets for safety and operational performance metrics at the same time it adopts the metrics, or at a later time?
- Should the Commission adopt quality of service and management metrics for PG&E in this proceeding? If so, what are appropriate metrics? Are there other aspects of D.20-05-053 concerning metrics that should be clarified or implemented here, such as identifying a metric to assess levels of safety or risk-driven investments?

The November 17, 2020 SOMs Ruling provides the following guidance on developing SOMs:

- Must be suitable for use as triggering events as specified in the EOE Process approved in D.20-05-053 on PG&E's post-bankruptcy reorganization plan;
- Should propose attainable SOMs that, "if achieved, would ensure that PG&E provides safe, reliable and affordable service consistent with California's clean energy goals;"⁷⁰
- Should build upon and include the most relevant and meaningful safety metrics from those previously adopted by the Commission, and any additional metrics deemed useful, to provide a means to accurately assess safety and operational performance by an electric and gas IOU; and,
- Should be suitable, over time, for the Commission, intervenors, and the public to potentially use to gauge the

⁷⁰ Assigned Commissioner's Ruling and Proposals, issued February 18, 2020, in I.19-09-016.

safety and operational performance of all gas and electric IOUs.⁷¹

In addition, the SOMs Ruling indicates that the following guidance and existing data requirements should be considered when developing the SOMs:

- SOMs considerations as summarized in D.20-05-053;
- Direction adopted in D.20-05-053 on quality of service and quality of management metrics, “which should constitute a significant portion of the proposed ‘operational’ metrics;”⁷²
- Requirements for PSPS events adopted in R.18-12-005;
- S-MAP SPMs;
- The A.15-05-002 *et al* TWG Safety Metrics Guiding Principles included in appendices to D.19-04-020;
- Metrics submitted in quarterly reports pursuant to I.15-08-019;
- Tabular and spatial data submitted to the OEIS through WMPs;
- Data submitted pursuant to D.20-05-019, including documentation of “near hit” potential fire incidents;
- Data submitted as part of PG&E’s RAMP that could meet the goals and requirements of the SOMs as outlined in D.20-05-053; and,
- Metrics related to compliance with General Order (GO) 95 and other Commission regulations that are reported to and tracked by the Commission’s Safety and Enforcement Division (SED).⁷³

The SOMs Ruling instructs PG&E to consult with SCE, SDG&E, and SoCalGas prior to proposing SOMs because the Commission may consider

⁷¹ SOMs Ruling at 1-2.

⁷² SOMs Ruling at 2.

⁷³ *Id.* at 2-3.

applying SOMs to all IOUs. The SOMs Ruling instructs PG&E to exclude any new Electric Overhead Conductor metrics from its SOMs proposal because Commission Staff are preparing a Staff Proposal on this topic. The SOMs Ruling indicates that a final set of proposed SOMs prepared by PG&E and/or Commission Staff would be issued via ruling in early 2021 and parties would be provided another opportunity to file comment at that time.⁷⁴

10.3 PG&E SOMs Proposal

On January 15, 2021, PG&E filed a proposal for 12 SOMs (PG&E SOMs Proposal) in response to the SOMs Ruling.⁷⁵ Several parties filed initial comments on PG&E's SOMs Proposal on January 25, 2021.⁷⁶ SPD Staff convened a public workshop on January 28, 2021, where PG&E presented its SOMs Proposal. On February 1, 2021, the ALJ issued a ruling requesting several clarifications from PG&E on issues discussed at the workshop.

PG&E's February 12, 2021 response to the ALJ ruling proposed an additional SOM on public safety. PG&E suggested a SIF Actual (Public) SOM defined as:

Incidents determined to be life-threatening, life-altering, or fatal to the public resulting from work on or caused by a failure or malfunction of PG&E facilities.⁷⁷

⁷⁴ *Id.* at 5.

⁷⁵ PG&E, "Response to Assigned Commissioner's Ruling Regarding Development of Safety and Operational Metrics," January 15, 2021 (PG&E SOMs Proposal).

⁷⁶ See Opening Comments on PG&E's Proposed SOMs, filed on January 25, 2021 by TURN, SCE, SDG&E/SoCalGas and Cal Advocates, and late-filed Opening Comments filed by MGRA on February 17, 2021.

⁷⁷ PG&E, "Response of PG&E to ALJ Ruling Regarding SIF Potential," February 12, 2021 at 8.

On March 1, 2021, several parties filed additional comments on PG&E's proposal and responded to questions in the ALJ's February 1, 2021 ruling.⁷⁸

On April 1, 2021, a Track 2 working group meeting discussed PG&E's SOMs Proposal. PG&E's proposed SOMs are listed in Table 1:

Table 1: PG&E's Proposed SOMs⁷⁹

Proposed Metric	Risk(s)
Serious Injuries and Fatalities (SIF) – Actual (Employee & Contractor)	Employee and Contractor Safety
SIF – Potential (Employee & Contractor)	Employee and Contractor Safety
Gas Dig-In Rate	Loss of Containment on Gas Transmission or Distribution Pipeline
Large Overpressure Events	Loss of Containment on Gas Transmission or Distribution Pipeline
Gas Emergency Response	Loss of Containment on Gas Transmission or Distribution Pipeline
Reportable Fire Ignitions	Wildfire
Transmission and Distribution (T&D) Wires Down	Failure of Electric Distribution Overhead Assets; Wildfire
Electric Emergency Response	Failure of Electric Distribution Overhead Assets
Safe Dam Operating Capacity	Large Uncontrolled Water Release
DCPP Reliability & Safety Indicator	Nuclear Core Damaging Event
System Average Interruption Duration Index (SAIDI) (Unplanned)	Failure of Electric Distribution Overhead Assets
Average Speed of Answer for Emergencies	Multiple Risks
Public Safety ⁸⁰	Multiple Risks

⁷⁸ Reply Comments filed on March 1, 2021 by Cal Advocates, TURN, SCE, SDG&E/SoCalGas, PCF, and MGRA, as well as reply comments filed also on March 1, 2021 by PG&E.

⁷⁹ PG&E, "Response to Assigned Commissioner's Ruling Regarding Development of Safety and Operational Metrics," January 15, 2021 at 5-6.

⁸⁰ PG&E, "Response of PG&E to ALJ Ruling Regarding SIF Potential," February 12, 2021 at 8.

PG&E states that its proposed SOMs address its most significant safety and reliability risks, prominently figure “leading metrics,”⁸¹ rely on objective data, are outcome-based, and measure factors that are primarily within the utility’s control. PG&E states that its proposed SOMs can be benchmarked, to the extent practical, against and used by other utilities and can be used to track “quality of service and quality of management” issues.⁸²

10.3.1 Party Comments on PG&E’s Proposed SOMs

In comments on January 25, 2021, March 1, 2021 and during the January 28, 2021 workshop, parties and Staff indicate a variety of concerns with PG&E’s proposed SOMs. MGRA states that “the proposed SOM metrics do not lend themselves to being used as triggering events for the [EOE] Process – in fact one of them (wildfire ignitions) would create a perverse incentive to overuse PSPS if used as a triggering event.”⁸³ MGRA further states that none of PG&E’s proposed metrics constitute an accurate gauge to measure changes in utility wildfire risk over time or adequately address PSPS risk. TURN, Cal Advocates, and PCF propose modifications to PG&E’s proposal and additional SOMs.

SCE and SDG&E/SoCalGas oppose applying any adopted SOMs to a utility other than PG&E, observing that the EOE Process was adopted with respect to that utility only. Parties voice concerns and recommendations with regards to the process and timing for setting targets for PG&E’s proposed SOMs.

⁸¹ PG&E’s SOMs Proposal at 7-8 states that leading metrics “have a track record as predictors of future outcomes or trends” and can “indicate root causes of risk events.”

⁸² *Id.* at 7-10.

⁸³ MGRA, February 17, 2021 Comments on PG&E’s SOMs at 7.

In reply comments to the ALJ's February 2, 2021 ruling, PG&E urges the Commission not to adopt more than the 13 SOMs it proposed, stating that the EOE Process relies on many triggering events other than SOMs.

10.3.2 Discussion

We do not adopt PG&E's SOMs Proposal as submitted. However, we adopt many of the SOMs proposed by PG&E, some in modified format, while adopting the Staff SOMs Proposal, modified as discussed below. Although PG&E's SOMs proposal contained many good elements, we find it incomplete. The Staff Proposal we modify and adopt in sections 10.4. and 10.5 contains additional SOMs to those proposed by PG&E that address important safety areas.

We agree with SCE and SDG&E/SoCalGas that, at this stage, the Commission should only adopt SOMs that apply to PG&E for the purposes identified in D.20-05-053. Instead, this decision later adopts an expanded set of SPMs to apply to all IOUs.

10.4 Staff's High Level SOMs Proposal

On April 22, 2021, Staff circulated a Draft Staff Proposal on SOMs and requested informal comments from Track 2 working group members. The Draft Staff Proposal proposed a broader set of SOMs than proposed by PG&E. On May 4, 2021, Staff convened a Track 2 working group meeting to discuss the Draft Staff Proposal and requested informal written comments from working group members. Track 2 working group members provided Staff with informal written comments on the proposal on May 11, 2021.

On June 4, 2021, the ALJ issued a Staff Proposal for comment, including the following:

- Appendix B: Staff Proposal on Safety and Operational Metrics (Staff Track 2 Recommendations); and,

- Appendix C: Summary Table of Staff Proposed Safety and Operational Metrics (Staff SOMs Proposal).

This section discusses the Staff SOMs Proposal and party comments. We start by reviewing Staff's proposed SOMs' assessment and reporting requirements and party comments on these topics. We adopt Staff's proposed SOMs' assessment and reporting requirements in full, with the exception that we require PG&E to report its SOMs semi-annually (every six months) instead of annually. We also commit to one independent third-party audit of PG&E's SOMs data collection and reporting methodologies in the next three years.

Next, we review each SOM proposed by Staff, and party comments. We adopt 32 SOMs for application to PG&E only. Our final adopted SOMs reflect modifications, deletions and additions to the Staff proposal based on party comments. Appendix A to this decision provides a clean list of our adopted PG&E SOMs. Appendix E to this decision provides a redlined version of the Staff Proposed SOMs, with the modifications, deletions, and additions to the Staff Proposal adopted here indicated.

10.4.1 Staff's General Approach

Staff propose 41 new SOMs for PG&E in its Staff Track 2 Recommendations.⁸⁴ Staff indicate that their proposed SOMs are designed to meet two primary objectives: (1) to be suitable for use as triggering events as specified in the EOE Process; and (2) to be suitable, over time, for the Commission, intervenors, and the public to gauge the safety and operational performance of all gas and electric IOUs.⁸⁵ However, Staff propose that the

⁸⁴ Staff's Proposed SOMs listed 40 SOMs, but Staff proposed an additional quality of service SOM in section 9 of the Staff Proposal, which was inadvertently omitted from the list of Staff's Proposed SOMs.

⁸⁵ SOMs Ruling at 1-4.

SOMs apply exclusively to PG&E at this time for the purpose of prompting PG&E to improve its safety and operational performance.

Staff's Track 2 Recommendations indicate that Staff sought to identify SOMs that are objective, outcome-based, defined clearly, auditable/verifiable, enforceable, measurable over time, and preferably, leading indicators. As discussed below, Staff's proposed SOMs cover a variety of topic areas including worker and contractor safety, electric safety risks, electric reliability, ignitions, gas safety risks, quality of service, customer satisfaction, and clean energy goals.

Staff recommend that PG&E report SOMs, including historical data, on an annual basis. Staff also propose that PG&E provide SPD with a copy of any report filed more frequently than annually with the Commission that contains SOMs, at the same time the report is filed with the Commission.

10.4.2 Staff's Proposed Reporting Requirements and Review Methods

Staff recommend that PG&E, as part of its annual SOMs submittals, propose one-year and five-year targets for each SOM and include a narrative discussing its current and planned activities to achieve these targets. Specifically, Staff recommend that for each SOM, the Commission require PG&E to annually submit the following:

Staff's Proposed PG&E SOMs Reporting Requirements

For each SOM, provide the following:

- An annual report, including all available historical data;
- A proposed target for the year following the reporting period for each metric and a five-year target, with the proposed target represented as specific values, ranges of values, a rolling average, or another specified target value;
- A narrative description of the rationale for selecting the target proposed and why a specific value, a range of

values, a rolling average or another type of target is selected;

- A narrative description of progress towards the proposed annual and five-year targets;
- A narrative description of any substantial deviation from prior trends based on quantitative and qualitative analysis, as applicable; and,
- A brief description of current and future activities to meet the proposed targets.⁸⁶

Staff also propose that PG&E provide SPD with a copy of any report filed more frequently than annually with the Commission that contains SOMs, at the same time the report is filed with the Commission.

Staff state that they do not recommend that the Commission adopt “trigger event” thresholds at this time for the SOMs. Instead, Staff recommend that the Commission collect additional data on the SOMs prior to taking this step and revisit the issue at a later date. In the meantime, Staff propose to implement an “indicator light” approach to examine PG&E’s safety and operational performance against the SOMs.⁸⁷ Staff state they are open to exploring potential triggering thresholds with parties in the TWG following a period of collection and review of SOMs data.

Staff propose to use both qualitative and quantitative evaluations of PG&E’s performance against the adopted SOMs to identify potential indicators of trends or triggering events. Staff propose to analyze PG&E’s SOMs’ performance by examining anomalies and/or variances in performance trends associated with a single or multiple SOM(s), based on current and historical

⁸⁶ Staff Track 1 Recommendations at 8.

⁸⁷ *Id.* at 6.

quantitative data. Staff propose to evaluate the SOMs qualitatively using additional contextual information, such as exogenous factors including major events (*e.g.*, major storms, heat waves, and earthquakes). Staff propose to use this holistic evaluation approach to determine if PG&E is making “insufficient progress” or showing “poor performance” on any of the SOMs. Staff state they would provide the Commission with recommendations relevant to the EOE Process based on its findings using this process, if warranted, or may propose other action, as appropriate.⁸⁸

10.4.3 Party Comments

Cal Advocates recommends the Commission develop an independent, third-party auditing program for PG&E’s SOMs to ensure transparency and accountability. Cal Advocates states that PG&E’s track record of repeated safety failures and inconsistent, contradictory, and incomplete reporting makes this requirement necessary.⁸⁹

Cal Advocates further recommends that the Commission establish a framework to move towards specific thresholds and targets for PG&E’s SOMs and establish a working group specifically for this purpose. Cal Advocates recommends the working group undertake preliminary assessments of what constitutes reasonable thresholds for PG&E SOMs, what data already exists that could be applied towards thresholds, what data needs to be developed to get to a threshold, and what clear next steps are in terms of developing these thresholds. This could be followed by development of a Staff Proposal for formal consideration. Cal Advocates states that enforceable thresholds should be

⁸⁸ *Id.* at 7 and 13.

⁸⁹ Cal Advocates, “Comments on Staff Proposal” at 27-28.

identified as soon as possible to provide markers for the “clear roadmap” for how the Commission will monitor PG&E’s performance in delivering safe, reliable, affordable, clean energy, described in D.20-05-053.⁹⁰

10.4.4 Discussion

Staff’s proposed SOMs reporting requirements for PG&E and Staff’s proposed evaluation method of PG&E’s SOMs reports are reasonable and are adopted with the modification that PG&E shall report its SOMs semi-annually. We also clarify six SOMs for which PG&E may propose directional rather than numerical targets, if desired. Staff’s proposed approach is consistent with the Commission’s intent in D.20-05-053⁹¹ and will provide a useful framework for evaluating SOMs trends and context.

PG&E shall, on a semi-annual basis (*i.e.* every six months), file and serve its SOMs report in this proceeding, R.20-07-013, any successor S-MAP proceeding, and its most recent or current GRC and RAMP proceedings starting no later than March 31, 2022, with each annual March report covering the 12-month period of the previous calendar year (January - December) and each annual September report providing data from January through June of the current year. PG&E shall concurrently send a copy of its semi-annual SOMs report to the Director of the Commission’s Safety Policy Division and to RASA_Email@cpuc.ca.gov. Staff shall post PG&E’s semi-annual SOMs reports on the Commission website within 30 days of receipt.

⁹⁰ *Id.* at 30, citing D.20-05-053, Appendix A at 1.

⁹¹ D.20-05-053 at 39: “While any adopted metrics would be intended to measure PG&E’s future performance, the metrics themselves (and the process of their development) could take into consideration PG&E’s past performance, such as for the development of performance baselines or other measurement criteria. This issue can be addressed more appropriately in the proceeding to develop the metrics.”

We require PG&E to file its SOMs reports semi-annually because we want to closely monitor trends as reflected in the SOMs. However, it is reasonable that, after a five-year period starting from issuance of this decision, PG&E may in this or a successor proceeding serve and file a request to modify the frequency of SOMs reporting, if it wishes. If PG&E takes this step, it shall provide a rationale for this request.

We adopt Staff's proposal to use a holistic quantitative and qualitative "indicator light" method to assess if PG&E has shown "insufficient progress" on SOMs or has demonstrated "poor performance" as discussed in D.20-05-053. We agree with Staff that it is premature to adopt specific trigger thresholds at this stage without closely examining existing and historical data and trends and gaining more experience generally with the SOMs. We therefore do not adopt Cal Advocates' recommendation to immediately establish a new working group to develop a framework to move towards specific thresholds and targets for PG&E's SOMs. However, Staff and parties involved in the TWG established in this decision may examine this issue over time as data become available and experience is gained, as feasible given other priorities in this proceeding and may bring to our attention any recommendation for formal triggering event thresholds or targets that they subsequently develop.

We decline Cal Advocates' recommendation to develop an independent third-party audit program to collect SOMs data from PG&E. However, we direct staff to undertake an independent, third-party audit of PG&E's SOMs data collection and reporting processes within the next three years. The audit findings and report will be served to members of this proceeding's service list, or a successor proceeding, when complete. If this audit identifies significant discrepancies or concerns with PG&E's SOMs data collection or reporting

processes, we will revisit the need for a more permanent independent third-party auditing system at that time. We require PG&E shareholders to pay for this audit, as it stems from PG&E's reorganization plan approved by the Commission.

We have two options to secure an independent auditor. First, Staff may explore adding this scope of work to an existing auditor contract. Second, similar to the process recently adopted for the Independent Safety Monitor in Resolution M-4855, PG&E shall undertake the solicitation process, but the Commission's Executive Director or her designee will make the final selection.⁹² SPD Staff will direct PG&E in its support of drafting and issuing solicitation materials including a Request for Proposals (RFP). While PG&E will be involved with the RFP, the Commission's Executive Director or her designee will have the sole discretion to select the consultant from eligible candidates that respond to the RFP.

10.5 Staff's Detailed SOMs Proposal

In this section we review and adopt Staff's proposed SOMs, some with modifications. We split three of Staff's proposed SOMs in two to create separate SOMs reporting on primary and secondary distribution lines and transmission lines and adopt an additional SOM on SIF Actual (Public) for a total of 32 adopted SOMs. Our adopted SOMs are set forth as Appendix A. Appendix E contains a redlined version of the Staff SOMs Proposal as modified and adopted here. Each section below presents Staff's SOMs proposal followed by a review of party comments and discussion.

⁹² Resolution M-4855. *Approving and denying elements of Pacific Gas and Electric Company's Advice Letter 4401-G/6116-E Requests to Comply with Decision 20-05-053 to Implement an Independent Safety Monitor (ISM)*. Available as of September 1, 2021 at:

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M398/K031/398031023.PDF>.

We affirm here that SOMs may overlap with other triggering events described in the EOE Process, and both may overlap with the Commission's recently updated Enforcement Policy⁹³ and enforcement aspects of the SPMs adopted in D.19-04-020.⁹⁴ Because of the mention of "safe... service consistent with California's clean energy goals," the SOMs and the EOE Process may also overlap with questions regarding PG&E's compliance with California's GHG emissions reduction goals, other clean energy goals, California Occupational Health and Safety Administration (OSHA) rules, and other state laws and regulations.

10.5.1 SIF Related SOMs (#s 1.1 – 1.4)

Staff proposed four SIF related SOMs, as indicated below:

- 1.1: Rate of SIF Actual (Employee)
- 1.2: Rate of SIF Actual (Contractor)
- 1.3: Rate of SIF Potential (Employee)
- 1.4: Rate of SIF Potential (Contractor)

Staff did not propose a SIF Actual (Public) SOM, which PG&E had earlier proposed.⁹⁵ Staff asserts that this step is not necessary as severe criminal and civil penalties, and other consequences already result to PG&E from "spikes" in SIF Actual (Public) occurrences.⁹⁶

⁹³ Resolution M-4846, *Resolution Adopting Commission Enforcement Policy*, available as of September 1, 2021 at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M350/K405/350405017.PDF>.

⁹⁴ *Application of San Diego Gas & Electric Company (U902M) for Review of its Safety Model Assessment Proceeding Pursuant to Decision 14-12-025*, Phase Two Decision Adopting Risk Spending Accountability Report Requirements, D.19-04-020 at 33.

⁹⁵ PG&E, "Response to ALJ Ruling," February 12, 2021 at 8.

⁹⁶ Staff Track 2 Recommendations at 25.

10.5.1.1 Party Comments

Parties generally support Staff's proposed SIF related SOMs. However, Cal Advocates and TURN strongly recommend adoption of a SIF Actual (Public) SOM. These parties contend that this metric adds a comprehensive view of PG&E's safety performance and is critical to monitor and drive safety improvements and close safety gaps not encompassed by SIF metrics on employees and contractors.

In comments on the Staff Proposal, PG&E agreed with Staff and opposed adopting a SIF Actual (Public) SOM. However, as discussed above, PG&E had earlier stated that "a public safety metric should be included in the suite of SOMs" if the metric is limited to public safety incidents "*resulting from work on or caused by a failure or malfunction of PG&E facilities*" as opposed to any incident "*involving utility facilities or equipment,*" as the SIF Actual (Public) SPM #22, adopted in D.19-04-020, is defined.⁹⁷ PG&E states that additional work is needed to define and report a SIF Actual (Public) SOM, however. PG&E asked how it should establish controls and processes to identify when a member of the public's injury is life-threatening or life-altering and proposed to apply its definition to historical data and implement a "track-only" period to test and validate the metric.⁹⁸

Regarding Staff's proposed SOMs # 1.3 (Rate of SIF Potential (Employee)) and 1.4 (Rate of SIF Potential (Contractor)), Cal Advocates recommends the Commission reclassify these as SPMs. Cal Advocates observes that it is detrimental to safety to penalize a utility, its employees, or contractors for

⁹⁷ PG&E, "Response to ALJ's Ruling," February 12, 2021, at 8, emphases added; *see also* D.19-04-020, Attachment 1 at 6.

⁹⁸ *Ibid.*

reporting potentially hazardous conditions, and an increase in SIF Potential incidents may indicate either improved reporting or an increasing number of potentially hazardous conditions. Cal Advocates opposes use of SIF Potential as an SOM because that ambiguity may incentivize underreporting. In reply comments, PG&E agrees.

10.5.1.2 Discussion

We adopt a SIF Actual (Public) SOM for PG&E using a modified version of the definition PG&E offered in its February 12, 2021, filing, as follows:

A fatality or personal injury requiring in-patient hospitalization for other than medical observations that an authority having jurisdiction has determined resulted directly from incorrect operation of equipment, failure or malfunction of utility-owned equipment, or failure to comply with any Commission rule or standard. Equipment includes utility or contractor vehicles and aircraft used during the course of business.

We modify the definition of SIF Actual (Public) as proposed by PG&E in several ways (*see* section 10.3) and adopt this modified definition as part of the Staff Proposal. First, we remove the concept of “life-altering” as subjective. Second, we retain the concept that it must be “determined” that a fatality or serious injury resulted from or was caused by PG&E equipment but clarify this to state that any determination will be made by an “authority having jurisdiction.” Third, we found the phrase “resulting from work on or caused by failure or malfunction” to inadequately reflect the range of areas that should be tracked and considered; therefore, we add the phrase “resulting from incorrect operation of equipment.” Fourth, we specify that PG&E equipment includes not only stationary facilities but vehicles and aircraft.

We agree with Cal Advocates and TURN that adopting this as a SOM adds a comprehensive view of PG&E’s safety performance. Staff is correct that civil or

criminal penalties are applicable if authorities determine that an incident resulted from work on or was caused by a failure or malfunction of PG&E facilities. However, it is also appropriate that poor performance in this most serious of areas bears consideration in Commission use of the EOE Process. We also believe this SOM is appropriate to use in relation to PG&E executive compensation determinations.

We do not ask the TWG established in this decision to develop controls and processes to identify when a member of the public's injury is life-threatening or life-altering, as requested by PG&E, as this is unnecessary given the modifications we adopt here. Additionally, with regards to the required one- and five-year targets for SOMs adopted in Section 10.4.4 (presented in Section 10.4.2), we clarify that PG&E may propose directional targets (*i.e.* that do not consist of numerical values) for the adopted SIF Actual (Public) SOM.

Regarding Rate of SIF Potential SOMs (#1.3, 1.4), we do not adopt these as SOMs. Instead, as discussed in Section 11.4.2, we recategorize these as SPMs that will apply to all IOUs. We agree with Cal Advocates that because improved reporting can result in an increase in these metrics, they are best used to monitor trends, not as a basis to initiate enforcement actions.

10.5.2 Reliability Related SOMs (#s 2.1 – 2.12)

The Staff Proposal recommends the Commission adopt 12 reliability related SOMs. This includes seven SOMs related to system average interruption duration (SAIDI), system average interruption frequency (SAIFI), and customer average interruption duration index (CAIDI), three PSPS related SOMs and two SOMs related to system average outages due to vegetation and equipment damage in Tier 2 and Tier 3 high fire threat districts (HFTDs).

The reliability SOMs proposed by Staff are:

- 2.1: System Average Interruption Duration (SAIDI) (Unplanned)
- 2.2: System Average Interruption Duration (SAIDI) (All Outages)
- 2.3: System Average Interruption Frequency (SAIFI) (Unplanned)
- 2.4: System Average Interruption Frequency (SAIFI) (All Outages)
- 2.5: Customer Average Interruption Duration Index (CAIDI) (Unplanned)
- 2.6: Customer Average Interruption Duration Index (CAIDI) (All Outages)
- 2.7: System Average Customers Impacted (All Outages)
- 2.8: Number of PSPS events in a calendar year
- 2.9: Duration of each PSPS Event in hours in a calendar year
- 2.10: Number of customers Impacted by each PSPS Event in a calendar year
- 2.11: System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Major Event Days)
- 2.12: System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Non-Major Event Days)

**10.5.2.1 SAIDI, SAIFI, and CAIDI Related SOMs
(#s 2.1 – 2.7)**

10.5.2.1.1 Staff Proposal

Regarding its proposed SAIDI, SAIFI, and CAIDI related SOMs, Staff states that the:

Commission requires that SOMs track ‘quality of service and quality of management’ issues [footnote omitted]. Reliability risks go to the very heart of these service and management

priorities [footnote omitted]. According to the American Customer Satisfaction Index Energy Utilities Report 2020-2021 comparing utilities nationally, PG&E ‘remains worst in class for both electric service reliability and electric service restoration’ [footnote omitted]. Based on the 2019 Annual Electric Reliability Reports, which are submitted annually to the Commission, PG&E performed comparatively poorly across several reliability metrics compared to other California Investor-Owned Utilities (IOUs) [footnote omitted]. Providing reliable service is a fundamental responsibility of an IOU. As such, EOE Process... reliability metrics for PG&E are appropriate for inclusion.⁹⁹

SAIDI is a reliability metric that measures the average length of time of power outages that customers experience in a period of time.¹⁰⁰ Staff recommends the Commission adopt a SAIDI (Unplanned) SOM as proposed by PG&E, with slight modifications to the definition.¹⁰¹ Staff also recommends adoption of a SAIDI (All Outages) SOM to provide an additional perspective on all outage durations that better reflects customers’ experiences.

SAIFI is a reliability metric that characterizes the average number of sustained power interruptions for each customer in a calendar year.¹⁰² Staff proposes two SAIFI metrics. A SAIFI (Unplanned) SOM measures sustained interruptions, excludes planned outages and outages due to Major Event Days (MEDs), and would reflect the reliability of the grid during routine circumstances, according to Staff.¹⁰³ A SAIFI (All Outages) SOM would include

⁹⁹ Staff Track 2 Recommendations at 27.

¹⁰⁰ D.96-09-045, Appendix A, at 1.

¹⁰¹ Staff Track 2 Recommendations at 29.

¹⁰² D.96-09-045, Appendix A, at 1.

¹⁰³ PCF writes, “Normally these two reliability indices [SAIDI and SAIFI] are a pair, two hand-in-glove indicators of utility reliability (PCF Comments on PG&E Workshop, March 1, 2021, at 4-5).

the average frequency of all sustained interruptions, per customer, due to outages from all causes. Staff states that a SAIFI (All Outages) SOM would provide a more comprehensive picture of reliability performance under any outage circumstance, ranging from routine to extreme.

As defined by the Institute of Electrical and Electronic Engineers (IEEE) Standard 1366-2001, a Major Event Day is a day when the daily SAIDI exceeds a threshold value, T_{MED} , that is 2.5 standard deviations above the mean of the lognormal distribution based on daily SAIDI values for the previous five years.¹⁰⁴ Statistically, days having a daily system SAIDI greater than T_{MED} are days when the energy delivery system experiences stresses beyond those normally expected – such as severe weather.¹⁰⁵

Staff recommends adoption of two CAIDI SOMs. First, Staff recommends a CAIDI (Unplanned) SOM, which is a reliability metric addressing the average time required to restore service to customers affected by unplanned outages.¹⁰⁶ Staff states that a CAIDI (All Outages) metric would provide a comprehensive picture of reliability performance under any outage circumstance. Staff also recommends adoption of a System Average Customers Impacted (All Outages) SOM that addresses all transmission and distribution outages for any reason.

10.5.2.1.2 Party Comments

Parties raise a number of concerns with Staff's proposed reliability related SOMs. Cal Advocates states that the Commission should consider if some

¹⁰⁴ IEEE, Classification of Major Event Days, at 1-4, available as of August 12, 2021 at <https://cmte.ieee.org/pes-drwg/wp-content/uploads/sites/61/2003-01-Major-Events-Classification-v3.pdf>. See also <https://standards.ieee.org/standard/1366-2012.html>.

¹⁰⁵ D.16-01-008, Appendix A at 4. For the purposed of calculating this index, any interruption that spans multiple calendar days is accrued to the day on which the interruption began.

¹⁰⁶ D.16-01-008, Appendix B.

reliability related metrics should be adopted initially as SPMs. PG&E opposes Commission adoption of any reliability related SOM that pertains to “all outages,” including those proposed by Staff as SAIFI, SAIDI, CAIDI, and System Average Customers Impacted SOMs for the overarching reason that “SOMs should be attainable.”¹⁰⁷ Additionally, PG&E opposes these metrics because:

PG&E anticipates increased planned outages over the next couple of years to perform necessary safety work. By including planned outages, the Commission could potentially put PG&E into enhanced enforcement as a result of PG&E executing risk reduction work. This is counterproductive. Therefore, the Commission should not include these indicators, and instead adopt SOMs that properly measure utilities’ work towards system improvements.¹⁰⁸

PG&E further proposes the Commission consider reclassifying Staff’s proposed SAIDI, SAIFI, and CAIDI (All Outages) SOMs as SPMs and rejecting Staff’s proposed SAIFI and CAIDI (Unplanned) SOMs because these use the same data as would a SAIDI (Unplanned) SOM and would not add significant new insights into PG&E’s performance.

10.5.2.1.3 Discussion

We adopt Staff’s reliability related SOMs, #s 2.1 (System Average Interruption Duration (SAIDI) (Unplanned)) and 2.3 (System Average Interruption Frequency (SAIFI) (Unplanned)). These metrics are reasonable and provide insight into PG&E’s overall reliability performance, which we expect to show significant improvement in coming months and years.

We do not adopt Staff’s recommended SOMs for SAIDI, SAIFI, CAIDI, and System Average Customers Impacted (All Outages), *i.e.* SOMs #s 2.2, 2.4, 2.6

¹⁰⁷ PG&E, Comments on Staff Proposal at 15.

¹⁰⁸ *Id.* at 22.

and 2.7. We do not think it is useful to adopt SOMs that includes planned outages undertaken to perform safety or reliability improvements. We agree with PG&E that using such a SOM for enforcement purposes is problematic. Additionally, metrics that are substantially similar to SOMs addressing all outages are included in the OEIS WMP Guidelines on PSPS metrics.

We also do not adopt SOM #2.5 (Customer Average Interruption Duration Index (CAIDI) (Unplanned)) as the information this provides can be derived from SOMs #s 2.1 and 2.3.

10.5.2.2. PSPS Related SOMs (#s 2.8 – 2.10)

The SOMs Ruling directs PG&E to consider requirements regarding the management and minimization of PSPS events adopted in R.18-12-005 when developing and proposing SOMs.¹⁰⁹ D.19-05-042, D.20-05-051, and D.21-06-034 require the electric IOUs to submit a post event report on each PSPS event to the Commission within 10 days, regardless of whether de-energization has actually occurred, and the report must describe the quantitative and qualitative factors the IOU considered in calling, sustaining, or curtailing each PSPS event, among other details.¹¹⁰ Additionally, as of 2021, IOUs must include in their WMPs specific short, medium, and long-term actions they will take to reduce the impact of and need for PSPS events.¹¹¹ “Failure to comply” with PSPS protocols is an EOE Process Step 1 triggering event.¹¹²

¹⁰⁹ SOMs Ruling at 2 and 3.

¹¹⁰ D.19-05-042, Appendix A at A-22 – A-25; D.20-05-051, Appendix A at 9-10; D.21-06-034, Appendix A at A14 – A20.

¹¹¹ Resolution WSD-011, Attachment 2.2: 2021 OEIS WMP Guidelines Template, PSPS Guidance at 46- 28, available as of July 22, 2021 at <https://energysafety.ca.gov/wp-content/uploads/docs/wmp-2021/attachment-2.2-to-wsd-011-2021-wmp-guidelines-template.pdf>.

¹¹² D.20-05-053, Appendix A, at 1.

10.5.2.2.1 Staff Proposal

Regarding its proposed PSPS related SOMs, Staff state that, “[c]onsidering the significant impacts customers and communities may incur during a PSPS event, it is important for the Commission to include PSPS related metrics in the SOMs for purposes of the EOE Process,” because this will “further incentivize progress on the implementation of mitigation measures to reduce the impact of PSPS events on Californians.”¹¹³ Staff state that PG&E system improvements “should result in decreased trends in the duration, frequency, and number of customers impacted by PSPS events over time, even in the face of extreme weather conditions and dry vegetation.”¹¹⁴ Staff state that it is important to measure the duration of PSPS events from the first notification of a potential shutoff because customers, particularly access and functional needs customers, expend significant time and resources preparing for potential PSPS events. Staff state they could consider approaches to normalizing PSPS related SOMs to reduce their variability due to exogenous factors like weather patterns.

10.5.2.2.2 Party Comments

Regarding PSPS related SOMs, Cal Advocates recommends the Commission adopt six additional PSPS related SOMs to ensure that PG&E is completing meaningful work to reduce the effect and duration of PSPS events on customers. Cal Advocates states that its proposed PSPS related SOMs would provide a level of granularity needed to capture PSPS impacts on customers, to determine if repeat circuits and/or customers are affected by each PSPS event, and to identify areas that require additional mitigation efforts such as hardening and/or sectionalizing to reduce the impact and frequency of PSPS events on

¹¹³ Staff Track 2 Recommendations at 37.

¹¹⁴ *Id.* at 41.

communities. MGRA recommends that the Commission prioritize utility work that reduces the overall number and impact of PSPS events and consider a more rigorous and regular review of utility PSPS post-event reports.

In contrast, PG&E contends that the PSPS SOMs proposed by Staff and Cal Advocates would penalize PG&E's use of PSPS events to mitigate risk of a catastrophic wildfire, which it agrees are a "measure of last resort and should not be used excessively or as a substitute or proactive measures."¹¹⁵ PG&E argues that R.18-12-005 is the appropriate proceeding for Commission development of PSPS related policy guidance and that the most recent decision in that proceeding declined to adopt any "rigid triggers or criteria" that could remove flexibility from an IOU's decision to initiate a PSPS event, with discussion of this issue referencing safety concerns.¹¹⁶ PG&E states the Commission should reject Staff's proposed SOMs #2.8 – 2.10 because these would track raw PSPS-related data (number, size, and duration), which is not the appropriate basis on which to initiate enforcement actions.

10.5.2.2.3 Discussion

For multiple reasons, we do not adopt Staff's recommended PSPS related SOMs. We also do not adopt Cal Advocates' PSPS related SOMs at this time as these remain poorly defined. However, we require SPD Staff, in collaboration with SED and OEIS Staff, to carefully monitor PG&E's performance against the PSPS Guidelines established in R.18-12-005 (and subsequent proceedings), and PSPS related metrics required in the OEIS WMP Guidelines, and to report to us

¹¹⁵ PG&E, Comments on Staff Proposal at 17.

¹¹⁶ *Id.* at 23, citing D.21-06-034 at 23.

any concerning trends such that we may reconsider our decision on this matter as warranted.

Because PSPS events have the dual potential of both mitigating and aggravating safety risks, we are concerned that adopting PSPS related SOMs for enforcement purposes at this time sends a mixed message at best and/or the wrong signal at worst. We have clearly and consistently stated that IOUs must use PSPS events only as a very last resort to avoid severe wildfire risk events; we underscore that guidance again here.¹¹⁷

The Commission has open proceedings regarding PSPS events, including R.18-12-005 *Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions* and I.19-11-013 *Order Instituting Investigation on the Commission's Own Motion on the Late 2019 Public Safety Power Shutoff Events*, and OEIS has developed PSPS metrics within the OEIS WMP Guidelines.¹¹⁸ The PSPS related SOMs proposed by Staff and Cal Advocates are too blunt a tool to serve the purpose of minimizing PSPS events or mitigating their impacts on customers, in our view. Other tools are available for this critical purpose, including the Commission's inherent authority to conduct post-PSPS event reasonableness reviews at our discretion,¹¹⁹ requirements within the approved OEIS WMP Guidelines that IOUs extensively report on their rationale

¹¹⁷ D.21-06-034 at 17, citing D.19-05-042, Appendix A at A1; D. 20-05-051, Appendix A at 9

¹¹⁸ I.19-11-013 was closed by D.21-06-014 but was reopened solely for consideration of an application for rehearing.

¹¹⁹ D.21-06-034 at 24; *See also* D.21-06-014 Ordering Paragraph 1, which requires PG&E, SCE, and SDG&E forgo collection from customers of the portion of their authorized revenue requirement equal to estimated unrealized volumetric sales and unrealized revenue due to future proactive PSPS events, available as of September 1, 2021 at:

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M387/K099/387099293.PDF>.

for initiating PSPS events¹²⁰ and undertake targeted work to minimize and eliminate PSPS events,¹²¹ and requirements adopted in R.18-12-005 that IOUs identify impacts on vulnerable customers from PSPS events.¹²²

Additionally, the Phase I, Track 1 working group in this proceeding has been discussing potential methods for the IOUs to quantify safety impacts on customers from PSPS events to improve how PSPS events are modeled as risk events in the RDF. Section 7.3 directs Staff and parties to continue this work, including potentially developing a proposal providing more detailed guidance on this topic.

We also note that required OEIS WMP Guidelines metrics largely include Staff's proposed PSPS related SOMs.¹²³ It is appropriate in our view for SPD Staff to coordinate with OEIS Staff to review PG&E's performance against the OEIS WMP Guidelines and related PSPS metrics and the PSPS Guidelines established in R.18-12-005 (and subsequent proceedings) and to consider poor performance on these over time as part of the indicator lights in the Staff evaluation approach discussed in section 10.4.¹²⁴ The PSPS Guidelines are well

¹²⁰ Resolution WSD-011, Attachment 2.2: 2021 OEIS WMP Guidelines Template, PSPS Guidance at 47 and 56, available as of July 22, 2021 at <https://energysafety.ca.gov/wp-content/uploads/docs/wmp-2021/attachment-2.2-to-wsd-011-2021-wmp-guidelines-template.pdf>.

¹²¹ *Ibid.*

¹²² D.21-06-034 at Conclusion of Law 51, Appendix A at A16.

¹²³ PG&E 2021 WMP Update- Attachments. See Attachment 1 – All Data Tables Required by 2021 OEIS WMP Guidelines, Table 11, available as of July 22, 2021 at: <https://energysafety.ca.gov/what-we-do/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2021-wmp/>.

¹²⁴ The Commission and OEIS have a Memorandum of Understanding governing data sharing amongst other matters available as of September 10, 2021 at <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/20210712-cpucoeis-mousigned.pdf>.

established and the OEIS WMP PSPS event metrics are well defined, reporting on them has begun, and all IOUs are required to report in these areas, which allows for analysis across all IOUs.

10.5.2.3 SOMs on Outages in HFTDs (#s 2.11 – 2.12)

10.5.2.3.1 Staff Proposal

The OEIS WMP Guidelines reporting template currently contains granular categories of electric outage types including those caused by contact with vegetation and various types of equipment damage. Nonetheless, Staff propose two SOMs to track system average outages due to vegetation and equipment damage in Tier 2 (elevated) and Tier 3 (extreme) HFTDs. Staff’s proposed SOM #2.11 (System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Major Event Days)) would track the frequency of such outages during MEDs. The proposed SOM #2.12 (System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Non-Major Event Days)) would track their frequency during non-MED days.

Staff state that measuring outages due to vegetation contact or equipment damage can provide visibility into the effectiveness of an IOU’s vegetation management and maintenance programs, the condition of its electric assets, the robustness of its circuit protection, and the overall resilience of its circuits. Staff state that this can allow for the identification of hazard conditions, and that although generally a “lagging” indicator, can also be considered a leading indicator if areas or circuits subject to wildfire ignitions are identified prior to the ignition of a major wildfire.¹²⁵ Staff note that this metric is similar to but

¹²⁵ Staff Track 2 Recommendations at 43, citing MGRA’s Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 5.

provides additional granularity as compared to the Wires Down SOMs #s 3.1 – 3.3. This is because an outage due to vegetation contact is not necessarily accompanied by a wires down event.

Staff recommend that the Commission require PG&E reporting on these SOMs to delineate outages due to contact with vegetation versus those caused by equipment damage and outages occurring on distribution assets versus those occurring on transmission assets. For equipment damage related outages, Staff recommend that reported data be segregated by overhead versus underground assets.¹²⁶

10.5.2.3.2 Party Comments

As a general matter, PG&E opposes any SOMs limited to HFTDs only. PG&E argues that SOMs limited to HFTDs violate the SOMs Ruling guidance because SOMs limited to HFTDs are “detailed, focused metrics” that are “highly granular.”¹²⁷

PG&E also objects across the board to any SOM that includes MEDs, as Staff’s proposed SOM #2.11 does. PG&E’s concern with SOMs that include MEDs is that “by definition, [MEDs] are those where circumstances “*exceed [] reasonable design and or operational limits* of the electric power system.”¹²⁸ PG&E argues that adopting SOMs that include MEDs is improper because these are “not attainable or beyond PG&E’s control.”¹²⁹ Further, PG&E argues that adopting SOMs with MEDs creates a perverse incentive for PG&E to focus on

¹²⁶ *Id.* at 44.

¹²⁷ *Id.* at 14, citing Attachment A to the SOMs Ruling, which summarizes party comments regarding safety metrics made in D.20-05-053.

¹²⁸ *Id.* at 16.

¹²⁹ *Id.* at 15

system performance outside of reasonable limits without concurrently providing guidance on the improvements it should make.¹³⁰ PG&E contends that its performance on SOMs that include MEDs “will vary greatly regardless of PG&E’s commitment and the quality of its efforts” and there is “no reasonable workplan that PG&E could put in place” to meet any targets associated with SOMs that include MEDs.

In contrast, although TURN does not comment on SOMs #s 2.11 and 2.12, TURN states, more generally regarding SOMs that include MEDs, that:

...excluding [MEDs] would exclude information on PG&E’s operations under more extreme circumstances and provide a significantly incomplete picture of the safety of PG&E’s operations. PG&E’s success serving its customers is demonstrated by the provision of safe and reliable service both on a typical day and on MEDs when its system is most vulnerable. MEDs usually coincide with major storms and other weather events; events which PG&E argues are ‘beyond PG&E’s control and are not predictable.’ While the weather may be outside of PG&E’s control, the utility’s response to weather events is wholly within its control.¹³¹

MGRA supports Commission adoption of SOMs #s 2.11 and 2.12. MGRA emphasizes that “utilities are responsible for preparing their systems to withstand location conditions.”¹³² Like TURN, MGRA contends that it is exactly during fire-weather and other severe weather events that a utility’s “preparedness, resilience, and operational capacity” have the greatest impact on

¹³⁰ *Ibid.*

¹³¹ TURN, Reply Comments on Staff Proposal at 8.

¹³² MGRA, Reply Comments on Staff Proposal at 10, citing to D.17-12-024 *Decision Adopting Regulations to Enhance Fire Safety in the High Fire-Threat District*, which states, “[a]lthough today’s Decision does not adopt [Proposed Regulation] 10, this does not relieve utilities of their duty under Pub. Util. Code § 451 and Rule 31.1 to design, build, and maintain facilities based on known local wind conditions.”

public safety.¹³³ MGRA states that metrics that can be influenced by external driver events such as weather conditions should be “normalized,” “prior to setting any benchmarking, performance goals, or triggering thresholds.”¹³⁴ However, MGRA does not contend that it is necessary for the Commission to have in place a specific normalization technique prior to adopting SOMs that include MEDs.

Cal Advocates does not comment on SOMs #s 2.11 and 2.12 but contends elsewhere that “[f]or the purposes of the SOMs, ensuring that PG&E adequately completes authorized and identified safety and reliability work, particularly in HFTD areas, is of the utmost importance.”¹³⁵

10.5.2.3.3 Discussion

Regarding SOMs relating to vegetation and equipment in HFTDs, we approve Staff’s proposed SOMs #s 2.11 and 2.12, which reflect system average outages due to vegetation and equipment damage in Tier 2 and Tier 3 HFTDs on both MEDs (#2.11) and non-MED (#2.12) days. Outages in HFTDs due to contact by vegetation and/or equipment damage should trend downward in coming years, regardless of weather patterns. SOMs #s 2.11 and 2.12 provide important tools for this Commission to track and hold PG&E accountable for progress on this goal.

We disagree with PG&E that it should not be required to plan for or be held accountable to reducing outages caused by vegetation or equipment damage during all types of weather. Instead, we reaffirm, as noted by MGRA, that PG&E has a duty under Section 451 and Rule 31.1 to design, build, and

¹³³ MGRA, Reply Comments on Staff Proposal at 12.

¹³⁴ MGRA, Reply Comments on Staff Proposal at 12.

¹³⁵ Cal Advocates, Comments on Staff Proposal at 20.

maintain facilities based on known local wind conditions. As stated by TURN and MGRA, while weather events are important drivers, they are not determinative of outcomes. It is exactly under strong weather conditions that the utility's preparedness and operational capacity have the greatest impact on public safety.

We note MGRA's recommendation regarding normalization of data as it relates to thresholds, benchmarks, or performance targets. We agree with MGRA that more data and analysis are needed to develop appropriate normalization methodologies. We encourage Staff to further explore this topic as resources permit and invite parties to provide Staff with normalization methodologies that may be feasible for this purpose as they become available.

In addition, we clarify that regarding the required one and five-year targets for SOMs adopted in Section 10.4.4 (presented in Section 10.4.2), PG&E may propose directional targets (i.e. that do not consist of numerical values) that consider exogenous factors such as extreme weather events for Staff's proposed SOM #2.11 System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Major Event Days) (SOM # 2.3 as adopted here). MEDs are currently excluded from many utility reporting requirements. This makes it challenging to specify a number or rate of wire down incidents that could be seen as acceptable at present, (i.e., that could comprise the basis of numerical targets). However, we believe that PG&E equipment must show greater resiliency to MEDs over the longer-term, even if there is some volatility year-to-year due to the uncertain nature and severity of these types of events. Authorizing PG&E to propose directional targets for this SOM strikes a reasonable balance between this aim and current data constraints.

SOMs #2.11 and 2.12 appear not to track vegetation contact or equipment damage on de-energized lines during PSPS events because events of this nature could not cause an outage on an already de-energized line. However, assessments of equipment damage or vegetation contact occurring during a PSPS event that would likely have caused an ignition had the line been energized may provide important information on IOU wildfire preparations.¹³⁶ We encourage Staff to consider this topic while reviewing PG&E's SOMs performance and perhaps when considering any future modifications to our adopted SPMs.

PG&E's assertion that SOMs restricted to Tier 2 and Tier 3 HFTD are "improper" is specious and ill-advised. This is particularly true given that Tier 2 and Tier 3 HFTDs comprise over 50 percent of PG&E's service territory and represent the customers most vulnerable to extreme wildfire risk.

10.5.3 Electricity Related SOMs (#s 3.1 – 3.15)

Staff proposed 15 electricity related SOMs, including three SOMs related to wires down events, eight SOMs related to patrols, inspections and compliance, and four SOMs related to ignitions and wildfire. Staff's proposed electricity related SOMs are as follows:

- 3.1 Wires Down Major Event Days in HFTD Areas
- 3.2 Wires Down Non-Major Event Days in HFTD Areas
- 3.3 Wires Down Red Flag Warning Days in HFTD Areas
- 3.4 Overhead Distribution Patrols Compliance in HFTD Areas
- 3.5 Overhead Distribution Detailed Inspections Compliance in HFTD Areas

¹³⁶ See Technosylva Inc. 2019 PSPS Event Wildfire Risk Analysis Report, which is not part of the record of this proceeding. Available as of July 22, 2021 at: <https://www.cpuc.ca.gov/consumer-support/psps/technosylva-2019-psps-event-wildfire-risk-analysis-reports>.

- 3.6 Overhead Transmission Patrols Compliance in HFTD Areas
- 3.7 Overhead Transmission Detailed Inspections Compliance in HFTD Areas
- 3.8 Distribution Vegetation/Conductor Clearance Inspections in HFTD Areas
- 3.9 Transmission Vegetation/Conductor Clearance Inspections in HFTD Areas
- 3.10 Backlog Compliance Metrics in HFTD
- 3.11 Electric Emergency Response Time
- 3.12 Number of CPUC-Reportable Ignitions in HFTD Areas (Distribution)
- 3.13 Percentage of CPUC-Reportable Ignitions in HFTD (Distribution)
- 3.14 Number of CPUC-Reportable Ignitions in HFTD (Transmission)
- 3.15 Percentage of CPUC-Reportable Ignitions in HFTD (Transmission)

10.5.3.1 SOMs Related to Wires Down Events (#s 3.1 – 3.3)

10.5.3.1.1 Staff Proposal

Staff's proposed SOMs #s 3.1- 3.3 address wires down events in Tier 2 and Tier 3 HFTDs, with SOM #3.1 based only on MEDs, SOM #3.2 excluding MEDs, and SOM #3.3 based only on red flag warning days.¹³⁷ As proposed by Staff, metrics #s 3.1 – 3.3 would track all risk events involving transmission or primary distribution conductors that contact the ground or a foreign object, such as a

¹³⁷ According to the National Weather Service, a Red Flag Warning means warm temperatures, very low humidity, and stronger winds are expected to combine to produce an increased risk of (vegetation) fire danger in an area within the next 24 hours. Specific weather parameters that are forecasted to be met for a Red Flag Warning Day are available as of September 13, 2021 at: <https://w1.weather.gov/glossary/index.php?word=red+flag+warning>.

structure, vehicle, or tree. Staff state that analyzing trend data in these areas may help identify problem spots and serve as a leading indicator to predict future potential failures. Staff state that tracking wires down by distribution and transmission systems and their segments will help the Commission determine whether utility operations and capital investments are resulting in safety improvements, as promised in annual WMPs, including success at system hardening. Staff state that PG&E should reduce wires down risk events in these circumstances and as such SOMs #s 3.1 – 3.3 are suitable for use with the EOE Process.¹³⁸

Staff strongly recommend the Commission include MEDs in wires down SOMs, providing the following rationale:

Since design and maintenance requirements for overhead circuits as specified in GO 95 do not reference [MEDs], there is no direct linkage between a circuit failing on a [MED] and violation of GO 95's design and maintenance requirements. GO 95 specifies wind loading force related minimum strength requirements for overhead conductors in GO 95 Sections 43.1 and 43.2. These wind loading forces can be translated into minimum wind speeds that different conductor types must be able to withstand. Coupled with local wind gust speed data, PG&E could potentially determine whether a particular conductor failed below the minimum wind speed. Nevertheless, failure in this particular conductor may not be solely due to wind loading/speeds.

A metric that measures failure of overhead conductors on [MEDs] gives visibility to the vulnerability of PG&E's overhead electric assets to extreme weather events. As indicated earlier...this metric has relevance in the context of

¹³⁸ Staff Track 2 Recommendations at 46, citing Hayes, Scott *et al.*, Pacific Gas & Electric Company, *Wires Down Improvement Program at PG&E*, Western Protective Relay Conference 2015, states that wires down tracking started at PG&E in 2010 and developed into a corporate public safety metric in 2012.

risk-based decision making and the expectation for a utility to address safety and reliability risks, notwithstanding extreme weather events. Although a wires down [MED] metric by itself may not necessarily point to deficiencies in PG&E's compliance with design and maintenance requirements in GO 95, it can serve as an indicator to help direct attention to areas that warrant closer oversight by the Commission.¹³⁹

Staff notes that, historically, as reported by utilities, one third of wires down events, excluding MEDs, have been caused by with contact with vegetation, one third by equipment failure and one quarter by a third party.¹⁴⁰

10.5.3.1.2 Party Comments

Cal Advocates supports Staff's proposed SOMs #s 3.1 – 3.3 but recommends the Commission adopt separate SOMs for transmission and primary distribution.

PG&E objects to SOMs #s 3.1 – 3.3 because they include MEDs, HFTDs, and red flag warning days and, as such, are “not attainable” and “excessively granular.” PG&E also opposes Staff's proposed definition of wires down events, stating that the definition is confusing and includes low risk scenarios. PG&E requests the Commission clarify the definition of wires down event to indicate it applies to conductors or splices that become “physically” broken, not just electrically broken. PG&E states that the second condition of Staff's definition could be understood as including “an enormous number of very-low risk events that are not presently reported. It is common for ties holding conductors to fail.”¹⁴¹ PG&E asserts that tracking these occurrences would impose significant additional costs and burdens for little or no benefit. PG&E also raises concerns

¹³⁹ *Id.* at 51.

¹⁴⁰ *Id.* at 46.

¹⁴¹ PG&E, Comments on Staff Proposal at 30.

with regard to reporting wires down incidents caused by third parties, who are not held to GO 95 requirements, and requests the Commission ensure that wires down events included in a SOM cannot be triggered by third parties.

PG&E states that the Commission should reject Staff's proposed definition of wires down event and instead adopt the definition in place since 2013 and used by the electricity industry nationally and in WMP reporting: "[i]nstances where a normally energized electric transmission or primary distribution conductor is broken, or remains intact, and falls from its intended position to rest on the ground or a foreign object. A conductor is considered energized unless confirmed in an idle state (*i.e.*, normally de-energized) – excludes Major Event Days as defined by the IEEE."¹⁴²

10.5.3.1.3 Discussion

We adopt a modified version of Staff's proposed definition of "Wires Down" event for application to all electricity related SOMs (#s 3.1 – 3.14). As suggested by PG&E, we modify Staff's proposed definition to define wires down as occurring "when a normally energized overhead primary or transmission conductor is broken, or remains intact, and falls from its intended position to rest on the ground or a foreign object; a conductor is considered energized unless confirmed in an idle state (*i.e.* normally de-energized)," but remove or include MEDs as appropriate depending on the SOM. We find this definition to be suitable for our purposes for SOMs # 3.1 – 3.3 at this time. However, we incorporate Staff's proposed broader definition for "wires down" into a new "overhead conductor safety index" SPM that we adopt later in Section 11.4.2.

¹⁴² *Id.* at 31.

We agree with Cal Advocates' recommendation to adopt distinct wires down SOMs for transmission and primary distribution circuits and make this change to the final adopted SOMs #s 3.1 – 3.6. Separating reporting on transmission and primary distribution circuits will help Staff target problem areas in their review. We also modify Staff's proposed definition of Wires Down Red Flag Warning Days in HFTD Areas (SOM #3.1 as proposed; SOMs #s 3.5 and 3.6 as adopted) to better reflect the risk exposure associated with that metric. Rather than dividing wires down during red flag warning days in HFTD by circuit miles in HFTD, we replace the denominator in both instances with "Red Flag Warning Circuit Miles days." This refinement makes this metric substantially similar to the definition for a similar metric in the OEIS WMP Guidelines.¹⁴³ The definitions thus become "number of wires down events in HFTD Areas on Red Flag Warning Days involving overhead primary distribution (or transmission) circuits divided by Red Flag Warning Distribution (or Transmission) Circuit-Miles Days in HFTD Areas in a calendar year."

We discuss in Section 10.5.2.3 our rationale for adopting SOMs that include MEDs, or that are based solely on MEDs and/or on Tier 2 and Tier 3 HFTDs, and do not repeat that discussion here. However, regarding the required one and five-year targets for SOMs adopted in Section 10.4.4 (presented in Section 10.4.2), we clarify that PG&E may propose directional targets (i.e. that do not consist of numerical values) that consider exogenous factors such as extreme weather events for the final adopted SOMs #s 3.1 Wires Down Major Event Days in HFTD Areas (Distribution), 3.3 Wires Down Major Event Days in HFTD Areas

¹⁴³ OEIS WMP Guidelines, available as of September 15, 2021 at: <https://energysafety.ca.gov/wp-content/uploads/docs/wmp-2021/attachment-2.2-to-wsd-011-2021-wmp-guidelines-template.pdf>.

(Transmission), SOMs 3.5 Wires Down Red Flag Warning Days in HFTD Areas (Distribution) and 3.6 Wires Down Red Flag Warning Days in HFTD Areas (Transmission).

As noted above, MEDs and Red Flag Warning Days are currently excluded from many utility reporting requirements. This makes it challenging to specify a number or rate of wire down incidents that could be seen as acceptable at present, (i.e., that could comprise the basis of numerical targets). However, we believe that PG&E equipment must show greater resiliency to both MEDs and Red Flag Warning Days over the longer-term, even if there is some volatility year-to-year due to the uncertain nature and severity of these types of events. Authorizing PG&E to propose directional targets for these SOMs strikes a reasonable balance between this aim and current data constraints.

10.5.3.2 SOMs Related to Patrols, Inspections and Compliance (#s 3.4 – 3.11)

10.5.3.2.1 Staff Proposal

Utilities report maintenance related metrics on an annual basis as part of their WMPs and report these metrics separately for distribution and transmission systems. Some of the WMP metrics track total miles inspected and inspection findings. Reporting on relevant WMP metrics is separated into 28 sub-metrics to better inform the Commission about utility operations and grid conditions.

The Track 2 Staff Proposal proposes six SOMs addressing circuit patrols and inspections, SOMs #s 3.4 – 3.9. Staff state that SOMs #s 3.4 – 3.7 would track PG&E's performance on inspecting and maintaining distribution and transmission assets including conductors, connectors, poles, towers, crossarms, and other essential equipment to enable their safe operation, and on inspections or patrols of overhead circuits that occur less frequently than scheduled. Staff state that they consider inspections and patrols to be frontline defenses that

prevent hazardous conditions from developing or escalating into serious incidents. Staff recommend four SOMs in this area because of the value in having this level of granularity to help pinpoint deficient areas.¹⁴⁴

Staff state that they propose two additional vegetation and conductor clearance inspection compliance SOMs (#s 3.8 and 3.9) because vegetation-related inspections are recorded by circuit miles, as compared to patrol metrics, which PG&E tracks by number of structures inspected.

Staff propose an SOM addressing backlog compliance in HFTD (#3.10) and one on electric emergency response time (#3.11). Regarding its proposed backlog metric, Staff state that this SOM tracks the number and percent of overdue maintenance and implementation of corrective work orders in the last year, including work orders generated from patrols and inspections, electric system hardening programs, and enhanced vegetation management programs.

Staff observe that the longer system maintenance is delayed or the longer a deficient or unsafe condition remains uncorrected the greater is the likelihood for the condition to result in an actual incident. When an unsafe or deficient condition is corrected early, the extent of deterioration to the equipment is less, which typically reduces the likelihood and consequence of any incident.

Regarding its proposed electric emergency response time SOM (#3.11), Staff indicate that this SOM is based on one of PG&E's Proposed SOMs. Staff agree with PG&E that electric emergency response time is key to evaluating safety risks from failure of electric distribution overhead assets, quality of service, and quality of management.¹⁴⁵

¹⁴⁴ *Id.* at 53.

¹⁴⁵ *Id.* at 56.

Staff states that SOMs #s 3.1 – 3.11 have both lagging- and leading-indicator characteristics.

10.5.3.2.2 Party Comments

PG&E opposes Staff's proposed SOMs #s 3.4 – 3.7 and 3.10 regarding compliance with patrol and inspection requirements and work order backlog because they would apply only in Tier 2 and Tier 3 HFTDs. PG&E further notes that the Commission may revise GO 165 (General Order on Inspection Requirements for Electric Distribution and Transmission Facilities), including to update scope and cycle times for inspections and patrols, and so should defer adopting SOMs #s 3.4 – 3.7 and 3.10 at this time so as to not impose requirements that will be changed in the future. PG&E supports SOMs #3.8 if it is modified to refer to all PG&E service territory, not just Tier 2 and Tier 3 HFTDs.¹⁴⁶

Cal Advocates supports SOM #3.10 regarding backlog compliance as critical to ensuring that essential safety and reliability work occurs. It notes that uncompleted work orders and inspections have earlier been identified as key elements leading to the devastating Zogg, North Bay, and Camp fires. However, Cal Advocates recommends removing the term “compliance” from the metric to remove ambiguity.

Cal Advocates further proposes to add a new SOM #3.10.1 on safety and reliability work authorized but not scheduled. Cal Advocates observes that a February 2021 WSD audit indicated PG&E had failed to prioritize work identified as needed on its top 20 highest risk circuits, resulting in PG&E's placement in Step 1 of the EOE Process. Cal Advocates proposes to define its new proposed SOM as:

¹⁴⁶ *Id.* at Appendix A, A-9.

Safety and reliability work authorized in PG&E's [GRC] but not scheduled, measured... in authorized [dollars] versus dollars spent and units of work authorized versus units of work completed.¹⁴⁷

Cal Advocates states that Section 451 and Commission guidance in D.11-05-018 on PG&E's 2011 GRC mean that PG&E has the obligation to spend what is necessary to ensure safe service regardless of authorized cost levels, "even if that condition requires more expenditures than the Commission has authorized."¹⁴⁸ PG&E opposes this additional metric, stating that it is not necessary because the EOE Process already includes a trigger for "insufficient progress toward approved safety or risk-driven investments" and the suggested information is available in the annual RSAR.

Cal Advocates supports Staff's proposed SOM #3.11, Electric Emergency Response Time, with the modification that response times be defined in five-minute increments to align with General Order 112-F 1232.2c, proposed for use in SOM #4.4 regarding natural gas, rather than the 60-minute threshold proposed by Staff. Cal Advocates asserts that a 60-minute response threshold has in the past been inadequate to prevent severe injuries and PG&E should be capable of matching its average electric response time to that of natural gas odor calls of 21.8 minutes. Cal Advocates recommends that SPM #3, Electric Emergency Response Time, be similarly modified, as discussed below. PG&E supports SOM #3.11.

10.5.3.2.3 Discussion

We adopt Staff's proposed SOMs relating to inspections compliance and work order backlogs, with minor modifications. We disagree with and are

¹⁴⁷ Cal Advocates, Comments on Staff Proposal at 19.

¹⁴⁸ *Id.* at 25, citing D.11-05-018 at 31.

disturbed by PG&E's assertion that these SOMs are "too granular." We do not consider SOMs limited to the over half of PG&E's territory subject to elevated or extreme risk of wildfires to be a "narrow" focus.

We also disagree with PG&E's suggestion to defer adopting SOM #s 3.4 – 3.7 and 3.10 until such time as the Commission updates GO 165. As defined, these SOMs are independent of any specifications contained in GO 165. Staff's proposed SOMs are flexible and should remain applicable regardless of any future revisions to GO 165. However, we adopt a modified version of Staff's proposed SOM #3.10 Backlog Compliance Metrics in HFTDs. We change the name of the metric to "GO-95 Corrective Actions in HFTDs" as more appropriate and update the description to focus on the number of "Priority Level 2" notifications in Tier 2 and Tier 3 HFTDs, consistent with GO 95 Rule 18 provisions. This metric now aligns with SPM #43 as proposed by Staff (#29 as adopted) and is more clearly defined and aligned with the way work orders are generated.

We agree with Cal Advocates and remove the term "compliance" from Staff's proposed SOMs #s 3.4 – 3.7, as this term is unnecessary and adds confusion. We also modify these SOMs to add the word "missed" to the name of these SOMs to align them with SPM #33 (#26 as adopted).

We do not adopt Staff's proposed SOM #3.8 and #3.9 Distribution and Transmission Vegetation/ Conductor Clearance Inspections in HFTD Areas as there are no frequency requirements for such inspections in any General Order.

We modify Staff's proposed SOM #3.11 (#3.12 as adopted), Electric Emergency Response Time, to align it with SPM #3, with the same name, as adopted in this decision, focusing on average response times, to reflect outliers, and broadening the metric beyond just 911 calls. We do not adopt Cal Advocates'

suggestion to reduce the reporting duration threshold for SOM #3.11 from 60 to five minutes. A five-minute reporting threshold is too short as it is impractical to expect PG&E to respond to emergency calls in crowded urban areas or dispersed rural areas in five-minute increments or to measure PG&E's response at this level of detail.

We also do not adopt Cal Advocates' suggested additional SOM #3.10.1 addressing safety and reliability work authorized but not scheduled. Cal Advocates did not provide a clear definition for this proposed new SOM, and we agree with PG&E that the Commission can obtain this information through the RSAR reports.

10.5.3.3 SOMs Related to Ignitions and Wildfires (#s 3.12 – 3.15)

10.5.3.3.1 Staff Proposal

Staff propose four wildfire ignition SOMs (#s 3.12-3.15) based on the format required for similar reporting in the OEIS WMP Guidelines. Staff state that analyzing data on the number of ignitions in Tier 2 and Tier 3 HFTDs caused by PG&E equipment will give the Commission the ability to determine whether utility operations and capital investments are resulting in safety improvements. Figure 1 below shows the suspected primary causes of ignitions in PG&E service territory during the years 2014 – 2016.¹⁴⁹ Figure 2 below shows updated data on suspected primary causes of ignitions for the years 2017- 2020.

¹⁴⁹ Staff Track 2 Recommendations at 59.

Figure 1: PG&E Fire Incidents by Suspected Ignition Cause (2014 – 2016)

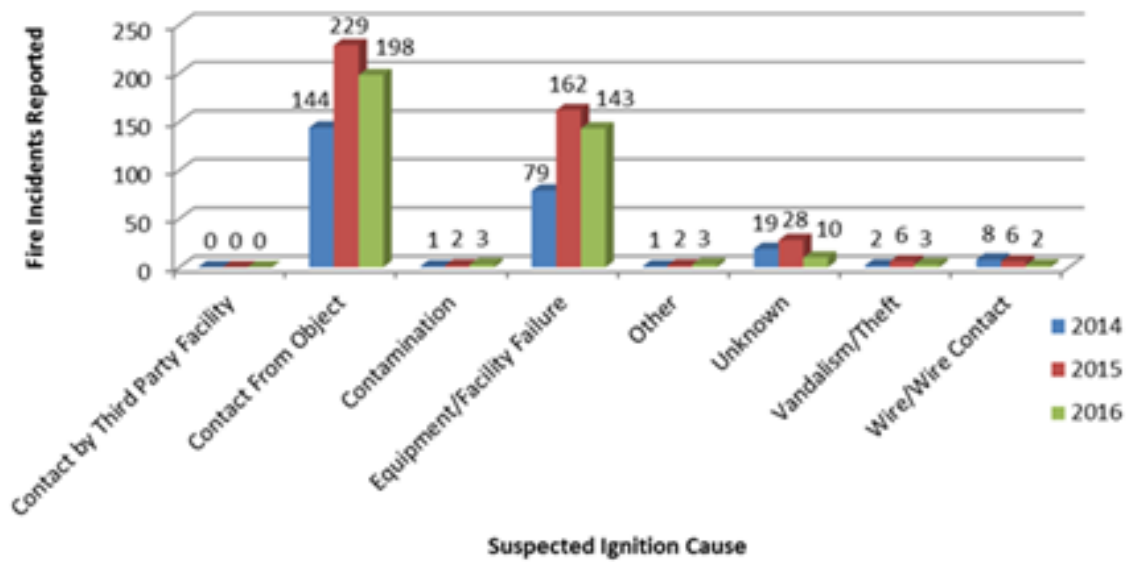
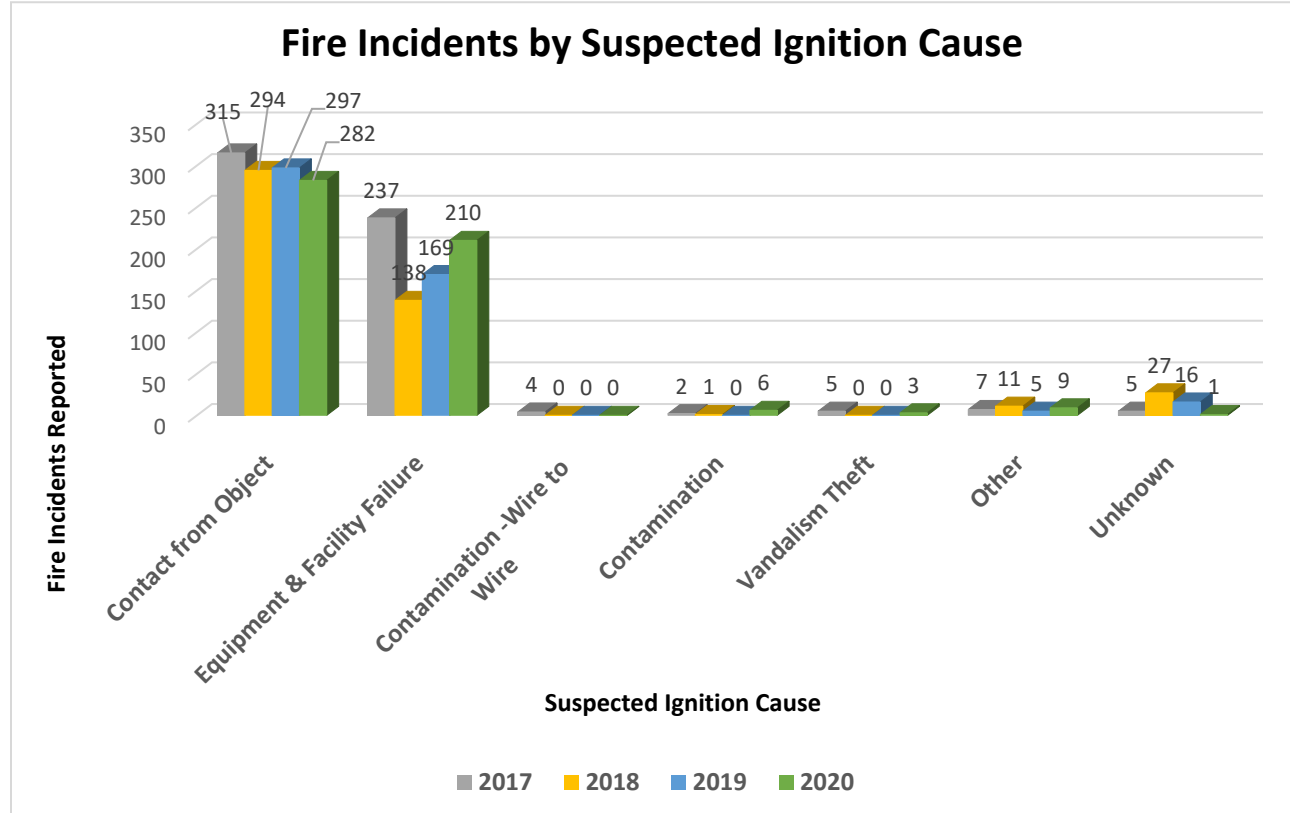


Figure 2: PG&E Fire Incidents by Suspected Ignition Cause (2017 – 2020)



D.14-02-015 adopted a “Fire Incident Data Collection Plan” that requires the large IOUs to collect and annually report certain information that would be useful in identifying operational and/or environmental trends relevant to fire-related events. However, reporting pursuant to D.14-02-015 excludes major fires under investigation or subject to litigation. To address this omission, Staff state that its proposed definitions for SOM #s 3.12 – 3.15 expand on that adopted in D.14-02-015 to include Commission reportable ignitions and any ignitions determined by any investigation conducted by the authority having jurisdiction to have originated from utility infrastructure.

10.5.3.3.2 Party Comments

Parties generally support Staff’s proposed SOMs relating to ignitions and wildfires. However, PG&E again argues that SOMs #s 3.12 – 3.15 are “excessively granular” because they refer only to Tier 2 and Tier 3 HFTDs. PG&E states it would support these SOMs if they were modified to combine reporting on transmission and distribution circuits in a single SOM.

10.5.3.3.3 Discussion

We adopt Staff’s proposed SOMs #s 3.12 – 3.15 with minor modifications to correct some typographical errors in Staff’s proposal. We agree with Staff that PG&E should report separately in these areas to ensure that the Commission has data disaggregated by distribution and transmission systems regarding ignitions. As stated earlier, we disagree with PG&E that SOMs targeting over half of PG&E’s service territory are “excessively granular.”

10.5.4 Natural Gas Related SOMs (#s 4.1 – 4.8)

Staff proposed eight natural gas related SOMs as follows:

- 4.1 Number of Gas Dig-Ins per 1000 Underground Service Alert tickets on Transmission and Distribution pipelines
- 4.2 Number of Overpressure Events

- 4.3 Normalized Overpressure Events
- 4.4 Time to Respond On-site to Emergency Notification
- 4.5 Gas Shut-In Time, Mains
- 4.6 Gas Shut-In Time, Services
- 4.7 Uncontrolled Release of Gas on Transmission Pipelines
- 4.8 Time to Resolve Hazardous Conditions

10.5.4.1 Party Comments

PG&E comments on Staff's proposed natural gas SOMs and recommends several modifications. First, PG&E recommends the Commission modify SOM #4.1 by revising the definition to better focus on the number of gas dig-ins per 1,000 Underground Service Alert tickets received for gas. PG&E suggests we eliminate SOM #4.3 because it is duplicative of SOM #4.2, with the addition of normalization to the number of pressure transducers, which Staff can calculate if they wish. PG&E recommends we specify "average" time reporting increments for SOM #4.4 regarding time to respond on-site to emergency notification to align this with American Gas Association reporting. PG&E recommends the Commission modify SOMs #s 4.5, 4.6, and 4.8 as proposed by Staff by replacing the recommended "average" time increments with "median" time increments and deleting reference to GO 112-F 123.2(e). PG&E also recommends we modify SOM #4.7 by defining reportable leaks as only those that are not reportable under Code of Federal Regulations (CFR) 191.3.

No other party commented on these SOMs.

10.5.4.2 Discussion

We adopt Staff's proposed SOMs #s 4.1 – 4.8 with modifications that reflect some but not all of PG&E's recommended changes. We modify SOM #4.1 as suggested by PG&E to better focus on the number of gas dig-ins per 1,000

Underground Service Alert tickets received for gas as reasonable and clarifying. We delete SOM #4.3 as redundant, as observed by PG&E. We accept PG&E's proposed modification to SOM #4.4 by requiring reporting based on average time increments; this aligns SOM #4.4 with time to respond on-site to emergency notification required by the American Gas Association. We accept PG&E's proposed modification to SOM #4.5, by requiring reporting based on median time increments and requiring PG&E to include as supplemental information the data used to determine median time increments as defined in GO 112-F 123.2(c). We also clarify SOMs #s 4.6 and 4.8 to require reporting of the median rather than average response time as more relevant in these instances.¹⁵⁰

We do not adopt PG&E's requested modification to SOM #4.7 to eliminate reporting of leakages required to be reported pursuant to 49 CFR 191.3. PG&E does not provide a rationale for this request, and we believe reporting the full number of leaks and failures that occur on transmission lines is reasonable and will provide us with essential safety oversight information.

10.5.5 Quality of Service and Management, Affordability, and Risk-Driven Investments

D.20-05-053 states that "the Commission will consider metrics to measure PG&E's quality of service and quality of management in the proceeding

¹⁵⁰ We generally prefer to require reporting based on median time as compared to average time because median is more likely to be reflective of a utility's systemic performance without undue influence from random outlier events. However, average time can also be a useful measures as it gives visibility to how a utility responds to random outlier events. To have a fuller visibility, both median and average would ideally be specified. For simplicity, this decision mostly requires reporting based on median time as more likely to reflect systemic performance. However, for both electric and gas emergency response time metrics (SOMs and SPMs) adopted here we require reporting based on average time to conform all of these metrics with the reporting format required by the American Gas Association.

addressing Safety and Operational Metrics.”¹⁵¹ Accordingly, the SOMs Ruling indicates that PG&E should consider guidance in D.20-05-053 on “quality of service and quality of management metrics, which should constitute a significant portion of the proposed ‘operational’ metrics.”¹⁵² The SOMs Ruling directs PG&E to include metrics on customer engagement, satisfaction, and welfare in its proposed quality of service and management metrics.

The Scoping Memo asks if the Commission should identify a metric to assess levels of safety or risk-driven investments, as discussed in D.20-05-053. Step 1 of the EOE Process includes a triggering event that would occur if PG&E demonstrates insufficient progress toward approved safety or risk-driven investments related to the electric and gas business.¹⁵³

10.5.5.1 Staff Proposals

For a quality-of-service SOM, Staff recommends an average speed to answer for emergencies metric, also proposed by PG&E. Staff indicate that other SOMs such as those on electric and gas emergency response time and SAIDI (unplanned) address quality of service as well. The Staff (and PG&E) proposal on this is as follows:

The Average Speed of Answer for Emergencies metric is a safety measure relating to multiple risks, as well as a quality of service and management measure, and is defined as follows:

Average Speed of Answer in seconds for Emergency calls handled in Contact Center Operations.¹⁵⁴

¹⁵¹ D.20-05-053 at 90.

¹⁵² Assigned Commissioner’s Ruling Regarding Development of Safety and Operational Metrics, November 17, 2021.

¹⁵³ D.20-05-053, Appendix A at 2.

¹⁵⁴ Staff Track 2 Recommendations at 72.

Staff state that this proposed SOM is a leading indicator, outcome-based, benchmarkable, and relies on objective data. Staff inadvertently omitted this proposed SOM from Appendix C to the Staff Proposal (Staff's Proposed SOMs), so we have added it into Appendices A and E of this decision.

Staff did not propose a quality-of-management metric. Staff assert that they believe other EOE Process elements sufficiently address this. Specifically, Staff point to the triggering event for EOE Process Step 1, relating to safety culture assessments. Staff observe that D.18-11-050 *Decision Ordering PG&E to Implement the Recommendations of the NorthStar Report* adopted over 60 safety culture improvement requirements, which are sufficient to address quality-of-management improvements in Staff's view.¹⁵⁵ Staff notes that SPD reviews quarterly reports from PG&E and regularly consults with North Star to ensure progress is being made on these recommendations.

Staff did not recommend an affordability SOM. Staff state that because the Commission approves PG&E rates, basing enforcement on the affordability of rates is problematic. Staff also did not recommend a specific SOM to track PG&E progress on risk or safety-related investments. However, Staff note that several of their proposed SOMs address this issue indirectly, primarily SOMs related to vegetation management and patrols.

10.5.5.2 Discussion

We adopt Staff and PG&E's proposed SOM on average speed to answer for emergencies as defined by Staff and PG&E with the clarification that this refers to the time increment it takes for an operator answer to a call, not an emergency crew's response time to the location of the emergency, which is

¹⁵⁵ Staff Track 2 Recommendations at 74.

addressed elsewhere. This is a reasonable metric to track quality of customer service as this relates to safety. We concur with Staff that given the other triggering events in the EOE process, it is unnecessary to adopt quality of management, affordability, and/or risk-driven investments SOMs at this time.

10.5.6 Clean Energy Related SOM (# 5.1)

D.20-05-053 describes SOMs as “attainable Safety and Operational Metrics that, if achieved, would ensure that PG&E provides safe, reliable, and affordable service consistent with California’s clean energy goals.”¹⁵⁶ In an effort to reflect the “clean energy” portion of this directive, the Staff Proposal recommends that PG&E report on any Commission established clean energy targets that it has “failed to meet” during the reporting period.¹⁵⁷ Staff state that they considered informal proposals from PCF and UCAN in this area but declined to incorporate these parties’ suggestions.

10.5.6.1 Party Comments

PCF comments that reducing GHG emissions furthers safety and reliability goals and argues that the Commission should adopt specific GHG and clean energy related SOMs and evaluate whether PG&E can more quickly reduce its GHG emissions. PCF suggests additional metrics related to total number of methane leaks, total methane loss from leaks, total number of vented emissions, total methane loss from vented emissions and others.

In comments on the proposed decision, PG&E comments that SOM #5.1 should be limited to PG&E’s minimum procurement obligation assigned to its bundled service customers because direct access load serving entities may have elected to opt-out of or failed to reach their own separate procurement

¹⁵⁶ D.20-05-053 at 38.

¹⁵⁷ Staff Track 2 Recommendations at 80.

obligations. PG&E also recommends we remove the phrase "zero-emitting" from the definition of the metric because D.19-11-016 does not include this term in its mandate.¹⁵⁸

10.5.6.1 Discussion

We adopt Staff's recommended clean energy SOM with one modification. We direct PG&E to report under SOM #5.1 on its progress towards PG&E procurement obligations as adopted in D.19-11-016 *Decision Requiring Electric System Reliability Procurement for 2021-2023*, D.21-06-035 *Decision Requiring Procurement to Address Mid-term Reliability (2023 - 2026)*, and any subsequent decision(s) adopted in R.20-05-003 *Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes* or a successor proceeding updating these requirements. Requiring PG&E to report on its progress towards the clean energy procurement goals adopted in these decisions aligns with direction in D.20-05-053 that the SOMs serve to track PG&E's provision of service consistent with California's clean energy goals. The final decision removes the phrase "zero-emitting" from the definition of this SOM but does not expressly limit reporting obligations to PG&E's bundled customers. PG&E's procurement obligations are specified in Commission decisions so we do not need to define those here.

We disagree with PCF that requiring PG&E to report on additional clean energy goals related to methane emissions under this SOM is warranted at this time. In D.17-06-015, the Commission established the Natural Gas Leak Abatement Program (NGLA Program) to reduce natural gas emissions of the jurisdictional gas companies in California, as directed by Senate Bill 1371 (Lara,

¹⁵⁸ PG&E, Comments on Proposed Decision, October 7, 2021 at 7-8.

2016). The program requires gas companies to report emission volumes annually and to file a compliance plan every two years. The NGLA Program adopted a base year of 2015 because 2013 emission levels could not be established due to the lack of the data at the time D.17-06-015 was adopted.

SB 1383 established a state-wide goal of reducing methane emissions forty percent below the 2013 level by the year 2030.¹⁵⁹ D.19-08-020 established a financial incentive for companies to demonstrate progress towards the 2030 target and adopted an intermediate goal of 20 percent reduction by 2025.¹⁶⁰ However, Commission Staff report that the methods currently available to estimate emissions under the NGLA Program and to track IOU progress against our adopted methane emission reductions goals lack sufficient accuracy to use as a SOM. As such, it is premature to adopt the metrics suggested by PCF.

We also do not adopt Staff's recommended approach that PG&E report on any clean energy goals that it "failed to meet," as this is vague. Instead, SOM #5.1 we adopt here reflects one of California's most important and most overarching clean energy goals.

We note that Staff's Track 1 recommendations propose increased attention to climate change as a risk driver in Phase II and section 9.2.2. directs Staff and parties to consider climate change issues as they develop an updated S-MAP Roadmap.

¹⁵⁹ SB 1383 (Lara, Chapter 395, Statutes of 2016)

¹⁶⁰ D.19-08-020 *Second Phase Decision Approving Natural Gas Leak Abatement Program Consistent with Senate Bills 1371 and 1383*.

11. Safety and Performance Metrics

11.1 Background on SPMs

The 2014 Risk Decision, adopted in the 2013 Risk Rulemaking, states that energy utilities' risk-based decision-making systems should be regularly evaluated in terms of the implementation of best practices, industry standards, and "the associated metrics of the security and safety" of its electric grid, gas pipelines, and facilities.¹⁶¹ Towards this end, the S-MAP Proceeding Phase I Scoping Memo directs Staff to develop and propose safety metrics.¹⁶²

D.19-04-020 adopts 26 SPMs to be used by the Commission to track the safety performance of the four IOUs. D.19-04-020 directed the IOUs to file their first set of SPMs by March 31, 2020, and annually thereafter, and to include data for the last ten years for all SPMs in each filing. D.19-04-020 also directed SED Staff to annually file a review of each IOU's SPM report, in a staggered schedule and directed SED Staff to convey the SPM reports and SED's reviews to the Electric Safety and Reliability Branch and the Gas Safety and Reliability Branch) of the Commission for "consideration when undertaking safety inspections and compliance audits."¹⁶³

D.19-04-020 discusses the potential bias that occurs when reporting SPMs associated with compensation. D.19-04-020 therefore requires the IOUs to clearly identify any SPMs linked to or used in any way for the purpose of determining executive compensation levels and/or incentives. D.19-04-020 requires the IOUs to provide a narrative contextualization for the SPMs.¹⁶⁴

¹⁶¹ D.14-12-025 at 6.

¹⁶² D.19-04-020 at 6.

¹⁶³ *Id.* at 33.

¹⁶⁴ *Id.* at 25-28.

D.19-04-020 emphasizes that the 26 SPMs it adopted was an initial list that may be added to and refined over time. D.19-04-020 directs Staff to biennially convene the S-MAP Proceeding TWG to discuss the SPMs and any needed changes, authorizes Staff to initiate Commission Resolutions to update the SPMs, and suggests that Staff and the TWG should prepare and periodically update a high-level SPM work plan.¹⁶⁵ D.19-04-020 indicates the Commission's intent that "[g]oing forward, the Commission should develop additional safety metrics that correspond to the top safety risks and top risk drivers identified in IOU RAMPs."¹⁶⁶

D.19-04-020 considers but did not adopt SPMs related to Safety Management Systems (SMS) and electric overhead conductors. Instead, D.19-04-020 directs Staff to reconvene the TWG established in A.15-05-002 *et al* to develop a proposal on these items to the extent feasible. D.19-04-020 directs the electric IOUs to initiate this work by proposing an updated electric overhead conductor "index" and associated safety metrics within 45 days. D.19-04-020 directs Staff to submit a proposal on electric overhead conductor metrics and SMS metrics within 180 days, if feasible. D.19-04-020 guidance on developing SMSs emphasizes the areas of safety decision-making, safety communications, continuous learning related to safety, backlog data, and near-miss data.¹⁶⁷

On June 30, 2019, the three large electric IOUs submitted a proposal on electric overhead conductor metrics to the S-MAP TWG. The three IOUs proposed metrics that could be considered as either standalone safety metrics or as component metrics to be used in an updated electric overhead conductor

¹⁶⁵ *Id.* at 24.

¹⁶⁶ *Id.* at 28.

¹⁶⁷ *Id.* at 21.

index. The S-MAP TWG held several meetings during the second half of 2019. Staff drew on these discussions to inform Staff's Proposed SPMs, and Section 11.4.2 of this decision adopts a new SPM #46 (SPM #32 in final) on overhead conductor safety index.

The S-MAP TWG also discussed SMS metrics but there was not broad party agreement on this topic and Staff did not further develop or offer proposals in this area.

The OIR in this proceeding asks if the Commission should consider adopting any SMS metrics and/or metrics related to electric overhead conductors.¹⁶⁸ Additionally, the Scoping Memo includes the following issues on SPMs:

- Should the Commission refine any of the 26 SPMs adopted in D.19-04-020? Should the Commission adopt additional SPMs to those adopted in D.19-04-020?
- Should the Commission develop a method to streamline SPM development and reporting across proceedings? If so, what methods should be considered?

On April 21, 2021, Staff informally circulated a Draft Staff Proposal to parties suggesting additions and modifications to the 26 SPMs adopted in D.19-04-02. On May 11, 2021, parties provided informal written comments to Staff on the Draft Staff Proposal.

The June 4, 2021 ALJ ruling issuing the Staff Proposal for comment appended a Staff Track 2 SPM proposal in Appendix D: Summary Table of Staff Recommended Modifications/ Additions to Safety Performance Metrics Developed Pursuant to D.19-04-020 (Staff SPM Proposal). The Staff Proposal

¹⁶⁸ RDF OIR at 37.

includes a discussion of Staff's considerations in developing the Staff SPM Proposal in section 11 of the Staff Track 2 Recommendations.

11.2 Staff's SPM Proposal

Of the 26 existing SPMs, Staff recommend that the Commission modify 16 of the existing metrics adopted in D.19-04-020, leave 10 unchanged, and adopt 19 new metrics, for total of 45 SPMs.

Most of the existing and proposed SPMs apply to either all IOUs or all electric or all gas IOUs. Seven existing SPMs apply only to PG&E, however, and Staff recommend that one of these be expanded to also apply to SCE, SDG&E, and SoCalGas. In some cases, Staff propose modest modifications to an existing SPM to align the definition with a proposed PG&E SOM. More generally, Staff propose updates to the definitions of existing SPMs to provide for greater consistency across the various Commission's proceedings.¹⁶⁹ Staff also recommend that Staff across Commission divisions work to better collaborate and coordinate on the development, organization, storage, and use of data and that analysis and enforcement could be streamlined if data were stored in an accessible repository for use by the public, parties, and the Commission.¹⁷⁰

11.3 Staff's Proposed Revisions to Existing SPMs

The 16 existing SPMs for which Staff proposed revisions are listed below:¹⁷¹

¹⁶⁹ Staff Track 2 Recommendations at 84.

¹⁷⁰ Staff Track 2 Recommendations at 81.

¹⁷¹ Staff's Proposed SPMs (Appendix D of Staff Proposal), June 4, 2021. Note that the list provided here only includes SPMs that Staff proposed to revise. See Staff's Proposed SPMs or D.19-04-020, Attachment 1 for the full list of adopted SPMs.

- SPM #1: Transmission & Distribution (T&D) Overhead Wires Down (Non-Major Event Days)
- SPM #2: Transmission & Distribution (T&D) Overhead Wires Down - Major Event Days
- SPM #5: Gas Dig-in
- SPM #6: Gas In-Line Inspection
- SPM #10: Cross Bore Intrusions
- SPM #11: Gas Emergency Response
- SPM #12: Natural Gas Storage Baseline Assessments Performed
- SPM #13: Gas System Internal Inspection Status
- SPM #14: Employee Serious Injuries and Fatalities
- SPM #17: Employee OSHA Recordables Rate
- SPM #18: Contractor OSHA Recordables Rate
- SPM #19: Contractor Days Away, Restricted, Transfer (DART)
- SPM #20: Contractor Serious Injuries and Fatalities

11.3.1 Party Comments on Staff's Proposed Changes to Existing SPMs

PG&E states that it largely supports Staff's proposed SPMs but proposes modifications in certain areas to address unclear descriptions that affect tracking and measurement, duplication, and alignment with SOMs.

SCE and SDG&E/SoCalGas state that the Track 2 working group had insufficient time to deliberate on many of Staff's proposed SPMs. These IOUs object to a number of SPMs as having ambiguous or contradictory definitions or because they state they may not have historical data for the SPM. SCE objects to 19 of Staff's proposed SPMs, PG&E objects to 18, and SDG&E/SoCalGas object to 13. TURN proposes modifications to three SPMs and Cal Advocates proposes six additional SPMs.

In reply comments, SDG&E/SoCalGas recommend that Staff's proposals for new SPMs be considered against these criteria:

- Specific and clear metric definitions/descriptions;
- Clear articulation of, and alignment with, a specific safety measurement objective;
- Clear units of measure;
- Ability to benchmark each utility (i.e., avoid metrics that aren't applicable when comparing a utility of size A to another utility of size B); and
- Ability for the utility to gather the data in a process that is neither onerous nor unnecessarily costly.

The IOUs object to Staff's proposed change to the definition of "wires down" used in SPMs #s 1 and 2 and instead recommend modifying the definition to be consistent with the overhead wires down definition required in the WMPs: "[i]nstance where an electric transmission or distribution conductor is broken and falls from its intended position to rest on the ground or a foreign object."¹⁷² The IOUs indicate they already report on a quarterly basis on this metric to OEIS and prefer to keep its definition consistent.

SDG&E recommends modifying SPM #3 so that it tracks emergency response times from all sources of reporting, including sources outside of 911 calls.¹⁷³ Cal Advocates recommends that the response time interval tracked and reported be reduced from 60 minutes to five-minute increments. SCE does not support these changes. SDG&E suggests modest changes to the definition in SPM #4, although Staff did not propose any changes to this metric.

¹⁷² SDG&E/ SoCalGas, Joint Comments on Staff Proposal at 14.

¹⁷³ SDG&E/SoCalGas, Joint Comments on Staff Proposal, Table 1. SoCalGas does not provide electricity and only joins SDG&E in commenting on the following SPMs #s 5, 6, 8, 9, 10, 13, 44, 45.

SDG&E/SoCalGas support Staff's modifications to SPMs #s 5 and 6, but propose further modifications to the definition such that it states "total miles of transmission pipelines inspected annually by inline inspection and percentage of miles inspected by inline inspection annually over total transmission pipelines". SDG&E/SoCalGas support Staff's proposed modifications to SPMs #s 8, 9, 10, and 11. SoCalGas supports Staff's SPM #12, which is not applicable to SDG&E. SDG&E/SoCalGas have concerns about duplication between SPMs #6 and #13, if modified as Staff suggest, stating that SPM #13 duplicates SPM #6. PG&E suggests modifying SPMs #s 8 and 9 to measure median not average shut-in gas time as more relevant. PG&E objects to Staff's proposed changes to SPM #11 and recommends the Commission retain the current definition, which centers around average response times, not the five-minute interval reporting as suggested by Staff. Regarding SPM #13, PG&E suggests that total miles inspected should be removed from this item as this information is included in PG&E's proposed alternative for SPM #6, and that percent of system "piggable" should be included as part of SPM #7, (percent "piggable" is based on miles upgraded) or should stand alone as its own metric.

SDG&E/SoCalGas support Staff's proposed SPMs #s 14 and 15. With SCE, these companies also support SPM #s 20, 21, and 23. SCE has concerns about Staff's proposed definition for SPMs #s 14, 17, 18 and 20 regarding employee and contractor SIFs Actual, with respect to differing definitions of "serious injuries and fatalities" used by OSHA and the Edison Electrical Institute (EEI) Occupational Health and Safety Committee. SCE generally supports using the EEI methodology. Regarding SPMs #s 17 and 18, SDG&E/SoCalGas recommend modifying the definition to remove the definition of "OSHA recordable" and references to the EEI. SDG&E /SoCalGas comment that using

the EEI Safety Classification and Learning Model to report on SPMs #s 17 and 18 as proposed by Staff (SPMs #s 15 and 16 as adopted) would require a costly reconfiguration of current methods and training systems for little gain.

SDG&E/SoCalGas state that their current method is substantially similar to the EEI method and is suitable for reporting purposes for these metrics.

Regarding SPM #s 14 and 20, PG&E requests that any SOMs and SPMs on SIF Actual be aligned. PG&E suggests eliminating SPMs #16 and 21 as the same information is included in SPMs #15 and 19.

Cal Advocates proposes SPMs #s 17, 18, and 22 be expanded to create three new SPMs that would track rate of SIF Potential as this relates to employees, contractors, and the public. Cal Advocates states that the existing SPMs are “lagging” metrics and its proposed SPMs are “leading” metrics, for which increased reporting can help to mitigate potential hazards.

SCE suggests moderate modifications to SPMs #22 on SIF Actual (Public). SCE supports PG&E’s proposed definition for the similar SOM #1.3, which excludes injuries and fatalities outside of an IOU’s control, for instance those caused by a third-party vehicle collision with utility assets. PG&E suggests changing the category of SPM #23 to “aviation” and the name of SPM #26 to Driver Call Complaint Rate.

11.3.2 Discussion

We modify 19 of the 26 existing SPMs, delete four, and adopt 10 new SPMs proposed by Staff, for a final total of 32 SPMs. The final adopted modified SPMs are provided in Appendix B. A redlined version of the adopted modified SPMs showing the changes from the Staff Proposal is provided in Appendix F. We make the following changes to Staff’s Proposed SPMs before adopting them:

- SPM #1: Transmission & Distribution (T&D) Overhead Wires-Down Non-Major Event Days: As suggested by the IOUs, we do not adopt Staff's proposed modifications to this SPM, instead reverting to the original form with minor clarifications to allow for consistent SPM and WMP reporting in these areas.
- SPM #2: Transmission & Distribution (T&D) Overhead Wires-Down Major Event Days: As suggested by the IOUs, we do not adopt Staff's proposed modifications to this SPM, instead reverting to the original form with minor clarifications to allow for consistent SPM and WMP reporting in this areas.
- SPM #3: Electric Emergency Response Time: As suggested by SDG&E, we slightly modify this SPM as proposed by Staff to remove references to 911 calling, to require reporting based on average time to respond, and to clarify its name by adding the word "time" to align with SOM #3.11 (#3.12 as adopted). We specified average for electric emergency response time to conform with the reporting format for gas emergency response time required by the American Gas Association. We do not adopt Cal Advocates' recommendation to reduce the reporting time period five-minute increments as unnecessary.
- SPM #4: Fire Ignitions: We slightly modify this SPM to remove the term "powerline involved" as recommended by SDG&E. We agree that including the term "powerline involved" may inappropriately prejudge the cause of a fire incident.
- SPM #5: Gas Dig-In: We revise this metric to exclude Underground Service Alert "tickets" generated by a utility and its contractors and to specify that the metric excludes fiber and electric tickets.
- SPM #6: Gas In-Line Inspection: As suggested by SDG&E/SoCalGas, we revise this metric modestly to add percentage of transmission lines inspected annually by in-line inspection. We do not delete this SPM as duplicative of SPM #13, as suggested by SDG&E/SoCalGas (see

discussion of SPM #13 below). SPM #6 now has two components, one reporting the total miles of transmission pipelines inspected, the other reporting on percentage of all transmission lines annually inspected by in-line inspections. The reporting of percentage facilitates benchmarking and comparison with other gas operators.

- SPM #7: Gas In-Line Upgrade: We slightly revise this metric for clarity, defining this now as “miles of gas transmission lines upgraded annually to permit in-line inspections” and adding the word “inspection” to the metric name.
- SPM #8: Shut In The Gas Average Time- Mains: As suggested by PG&E, we modify the metric description to specify a median reporting time requirement and simplify it by referencing GO 112-F 123.2(c). We change the name of the metric accordingly.
- SPM #9: Shut In the Gas Average Time Services: As suggested by PG&E, we modify the metric description to specify a median reporting time requirement and simplify it by referencing GO 112-F 123.2(c). We change the name of the metric accordingly.
- SPM #10: Cross Bore Instructions: We modify the metric description to specify that it is reported based on annual data and reclassify it as a lagging metric.
- SPM #11: Gas Emergency Response: We modify the metric description in response to PG&E comments to align it with the emergency response information specified in GO 112 F and to add additional clarity.
- SPM #12: Natural Gas Storage Baseline Assessments Performed: For clarity, we modify the metric description to require reporting in terms of percentage (number of assessments completed versus number of assessments scheduled or targeted) to facilitate benchmarking with other gas storage operators.
- SPM #13: Percentage of the Gas System that can be Internally Inspected: We change the metric name to “Gas

Pipelines that Can Be Internally Inspected,” modify the description to improve clarity and add percentage information to facilitate comparison across gas utilities. This metric now differs from SPM #6 in reporting the percentage of gas pipelines that are technically capable of being internally inspected as opposed to SPM #6, which reports the total miles of transmission pipelines inspected and the percentage of all transmission lines annually inspected by in-line inspections.

- SPM #14: Employee SIFs: We delete this metric as our modified SPM #17 on Rate of SIF Actual (Employee) captures the same information expressed more usefully as a rate, which allows for comparison across IOUs, and includes fatalities as well as serious injuries.
- SPM #16: Employee Lost Workday Case Rate: We delete this metric as suggested by PG&E since the information it captures is already included in SPM #15, DART Rate.
- SPM #17 (SPM #15 as adopted): Employee OSHA Recordables Rate: We change the name of this metric to Rate of SIF Actual (Employee) and generally specify use of the EEI Occupational Health and Safety Committee methodology, the “Safety Classification and Learning Model,” for counting serious injuries and fatalities as suggested by SCE. However, we additionally affirm that if a utility has implemented a replicable, substantially similar method for assessing SIF Actual, the utility may use that method for reporting this metric. If a utility opts to report the rate of SIF Actual using a method other than the EEI Safety Classification Model, it must explain how its methodology for counting SIF Actual differs and why it chose to use it. To ensure that this approach allows for comparison across utilities, we also require all utilities to report SIF Actual data based on OSHA reporting requirements under Section 6409.1 of California’s Labor Code. We take this approach because closer examination of the current SDG&E/SoCal Gas SIF Potential and Actual methodology has assured us the approach is substantially

similar to the EEI Safety Classification Model method. Allowing this flexibility minimizes compliance costs while still providing for suitable comparison across utilities.

- SPM #18 (SPM #16 as adopted): Contractor OSHA Recordables Rate: We change the name of this metric to Rate of SIF Actual (Contractor) and generally specify use of the EEI Occupational Health and Safety Committee methodology for counting serious injuries and fatalities as discussed with regards to SPM #17 above, with similar exceptions if a utility is using a “substantially similar” method. The final requirements for SPM #18 are the same as those required for SPM #17, as discussed above, for the same reasons.
- SPM #19: Contractor DART: We simplify the units of data collection to “OSHA DART Rate” and require SCE, SDG&E, and SoCalGas to report on this metric in addition to PG&E.
- SPM #20: Contractor SIF: We delete this metric as a new SPM on Rate of SIF Potential (Contractor) that we adopt below captures the same information expressed as a rate and is more useful since it provides information in a way that can be compared across utilities.
- SPM #21: Contractor Lost Work-Day Case Rate: We delete this metric because the information it provides is already included in the DART contractor SPM, as observed by PG&E.
- SPM #22: We do not modify the description of this metric to align it with SOM #1.3 as suggested by SCE, because reporting on this metric as currently defined has been working well to date and usefully provides a broader perspective than will be achieved with SOM #1.3.
- SPM #23: Helicopter/Flight Accident or Incident: We modify the category of this metric from “vehicle” to “aviation” as suggested by PG&E.
- SPM #26: Driver’s Check Rate: We change the name of this metric to “Driver Call Complaint Rate,” as suggested

by PG&E, and changed the metric description to specify utility-owned vehicles only.

We do not modify SPM #1 and #2 as suggested by Staff but instead retain the original SPM descriptions for these metrics as the existing descriptions reflect an approach used nationally and in WMP reporting and are supported by the IOUs. However, we reflect Staff's proposed modifications to SPMs #s 1 and 2 in a new SPM #46 (#32 in final version), "Overhead Conductor Safety Index," which we discuss below.

We do not adopt a Rate of SIF Potential (Public) as proposed by Cal Advocates because we are not clear on how the IOUs would calculate this metric. However, in Section 11.4.2 below, we adopt two new SPMs on Rate of SIF Potential (Employee) and Rate of SIF Potential (Contractor) as recommended by Cal Advocates.

We disagree with SCE and SDG&E/SoCalGas that there has been insufficient time for parties to comment on the SPMs. We have carefully reviewed parties' comments on the Staff Proposal and will consider other comments on the proposed decision. This decision reflects requested modifications when we have found them to be reasonable. The absence of historical data collection on an SPM is not in itself a sufficient reason to reject a metric if utility collection and reporting of the data helps to ensure public, employee, and contractor safety. The SPMs as modified here and adopted here and in section 11.4.2 below are reasonable and align with the criteria proposed by SDG&E/SoCalGas.

We direct the IOUs to submit reports on all SPMs as adopted here, and the new SPMs adopted in section 11.4.2, on an annual basis by March 31st, starting March 31, 2022, with each report covering the previous 12-month period.

The IOUs shall adhere to the guidance on submittal of SPMs adopted in D.19-04-020 when making their annual SPM report submissions, with two modifications. First, the IOUs shall serve and file their annual SPM reports in A.15-05-002 *et al*, R.20-07-013, and their most recent or current GRC. Second, the IOUs shall send their SPM reports to the Director of the Commission's Safety Policy Division and to RASA_Email@cpuc.ca.gov.

The updated numbering of the SPMs as modified and adopted here is provided in Appendices B and F.

11.4 Staff's Proposed New SPMs.

Staff's proposed 19 new SPMs (#s 27 - 45), are listed below.

- SPM #27: Median Time to Correct Inspection Findings, by Tiers or Grades
- SPM #28: Median Time to Correct Inspection Findings, no Segregation by Tiers or Grades
- SPM #29: CPUC-Reportable Overhead Conductor Failure Incidents
- SPM #30: Wires Down Remaining Energized
- SPM #31: Wires Down Root Cause Analysis
- SPM #32: Wires Down by Cause
- SPM #33: Missed Inspections and Patrols for Electric Circuits
- SPM #34: Missed Vegetation Management Inspections
- SPM #35: Overhead Conductor Wire Size Compliance in HFTD
- SPM #36: Overhead Conductor Wire Size Compliance in non-HFTD
- SPM #37: Infrared Inspections on Electric Distribution Circuits in HFTD
- SPM #38: System Hardening in HFTD Areas

- SPM # 39: System Undergrounding in HFTD Areas
- SPM #40: Enhanced Vegetation Management Work Completed
- SPM #41: Work Order Backlog
- SPM #42: Electric Work Order Backlog in HFTD
- SPM #43: GO-95 Corrective Actions in HFTDs
- SPM #44: Gas Overpressure Events
- SPM #45: Gas In-Line Inspections Missed

11.4.1 Party Comments on Staff's Proposed New SPMs

The IOUs, TURN and Cal Advocates and commented on Staff's new proposed SPMs. SDG&E /SoCalGas comment that using the EEI Safety Classification and Learning Model to report on the new SPMs proposed by Staff addressing Rate of SIF Potential (Employee and Contractor, SPM #s 17 and 18 as adopted), would require a costly reconfiguration of current methods and training systems for little gain. SDG&E/SoCalGas state that their current method is substantially similar to the EEI method and is suitable for reporting purposes for these metrics.

SDG&E supports Staff's suggested new SPMs #s 29 and 30 (the latter modified to clarify the definition of wires down), but SCE opposes including these as SPMs and PG&E states the definition is unclear. SCE, PG&E, and SDG&E support SPM #32, with SDG&E proposing to limit this to percentage of wires down causes as related to vegetation. SDG&E supports SPM #33 as does SCE for SPM #32, with some modifications to the definition.

SDG&E supports SPMs #s 34, 37 (with modifications to clarify reporting format), 39 (with clarifications on whether this is a 1:1 replacement or any time a line is undergrounded), and 43 (with modifications to clarify that the metric is

calculated as the percentage of completed infractions due for that year divided by the infractions due that calendar year), but SCE disagrees that these should be SPMs. SCE indicates it does not currently collect data on missed vegetation inspections and thus objects to SPM #34 (which mirrors SOM #3.11 and 3.12).

PG&E has concerns regarding the definitions of SPMs #34, 35, and 36 and requests that definitions used in SPMs #s 38 – 40 be modified to align with those required for reporting in the WMPs. TURN indicates concerns with SPMs #s 38, 39, and 40 as written, stating that these may encourage quantity over quality without consideration for effectiveness, risk ranking, or cost effectiveness. TURN suggests the Commission either eliminate or modify SPMs #s 38, 39, 40, with any clarification clearly indicating that work should be prioritized according to the most impactful work.

SDG&E/SoCalGas support SPM #44, and 45 (with modifications to redefine these as “the number of gas pipeline in-line inspections that missed the required reassessment interval”). SCE does not comment on these proposals. PG&E suggests modifications to the definition of SPM #45.

Cal Advocates proposes several additional SPMs. Cal Advocates proposes new SPMs #s 17.1 and 18.1, addressing Rate of SIF Potential (Employee) and Rate of SIF Potential (Contractor). Cal Advocates proposes a new SPM #22.1 on SIF Potential (Public) to encourage reporting of potential hazards by all IOUs. Cal Advocates proposes a new SPM #27.1 on Number of Repeat GO-95 Corrective Actions in HFTDs, a new SPM #41.1 on Safety and Reliability Work Authorized by Not Scheduled, and a new SPM #43.1 Number of Repeat GO-95 Corrective Actions in HFTDs.

SCE objects to Cal Advocates additional proposed SPMs as duplicative and poorly defined.

11.4.2 Discussion

We adopt nine of Staff's 19 proposed new SPMs as follows and adopt an additional SPM regarding Overhead Conductor Safety Index. SPMs that we do not discuss below are not adopted:

- New SPM #17: Rate of SIF Potential (Employee):¹⁷⁴ We adopt this metric for all IOUs instead of adopting it as a SOM just for PG&E. As noted by Cal Advocates, SIF Potential metrics are best reported as SPMs so as not to discourage employee reporting that could help improve safety conditions. We generally require use of the EEI Occupational Health and Safety Committee method, the Safety Classification and Learning Model, for reporting on this metric. However, as we did for SPM #s 17 and 18 above (SPM #s 15 and 16 as adopted), we allow a utility that has implemented a replicable and substantially similar method to assess SIF Potential to use that method to report on this metric. A utility using a substantially similar method must explain how their method for counting SIF Potential differs and why they chose to use it. This approach avoids costly changes to SDG&E /SoCalGas's methods and training that do not add substantial value. We also require all utilities to provide supplemental information about the key lessons learned from SIF Potential incidents.
- New SPM #18: Rate of SIF Potential (Contractor): We adopt this metric for all IOUs instead of adopting it as a SOM just for PG&E. As noted by Cal Advocates, SIF Potential metrics are best reported as SPMs so as not to discourage employee reporting that could help improve safety conditions. We adopt the same reporting requirements for this metric as described for New SPM #17 above.

¹⁷⁴ Note that SPM #17 as proposed by Staff (SPM #15 as adopted) addresses Rate of SIF Actual (Employee), whereas this new SPM #17 (as adopted) addresses Rate of SIF Potential (Employee). The same relationship holds for SPMs #s 16 and 18 as adopted.

- SPM #30: Wires Down Remaining Energized: We revise the name of this metric to “Wires Down Not Resulting In Automatic De-Energization” and, for clarity, as requested by PG&E, modify the description of this metric to specify reporting on wires down events that did not result in automatic de-energization by circuit protection devices. This metric now captures the ability of utility circuit protection devices to automatically de-energize downed conductors. The longer a downed conductor remains energized, the higher would be the likelihood of causing injuries, fatalities, and wildfires. Although the role of circuit protection devices is primarily to protect the integrity of the circuit and only secondarily to prevent other types of safety risks, we see value in having the visibility to see how effective those circuit protection devices are in preventing other safety risks.
- SPM # 33: Missed Inspections and Controls for Electric Circuits: We slightly modify the description of this metric for clarity purposes to emphasize the “annual number of overhead electric structures that did not comply with the inspection frequency requirements” as compared to the “total number of overhead electric structures with inspections due in the past calendar year.” Metrics tracking inspections are important since inspections serve as a front line of defense to reduce the likelihood and potential consequences of safety risks from deteriorating equipment, vegetation contact with conductors, and risks introduced by third-parties. The metric requires separate reporting for primary distribution and transmission overhead circuits, as well as for patrols and detailed inspections.
- SPM # 35: Overhead Conductor Wire Size in HFTD. For clarity, we modify the name of this metric to Overhead Conductor Size in Tiers 2 and 3 HFTD and the description of this metric to focus reporting on overhead primary distribution conductors made of #6 copper. Small gauge conductors such as #6 copper are particularly vulnerable to failure from contact with vegetation. Tracking the

- percentage of overhead primary conductors smaller than #2 and #4 copper conductors will help measure the amount of small primary distribution overhead conductors most prone to failure. Since #6 copper conductors are smaller and more prone to failure than #2 or #4 copper conductors, this is a suitable reference size to track for SPM #35. The suitability of #6 copper as a reference size for small overhead primary distribution conductors most prone to failure can be revisited in the future as needed.
- SPM #41: Work Order Backlog: We modify the name of this metric to “Gas Operation Corrective Actions Backlog,” and modify its description to specify reporting on gas operations corrective actions backlogs and 49 CFR Part 192. This metric gives visibility to a utility’s compliance with gas safety regulations and the utility’s promptness to correct deficiencies within an acceptable timeframe.
 - SPM #43: GO-95 Correction Actions in HFTDs: We modify the name of this metric to GO-95 Corrective Actions (Tiers 2 and 3 HFTDs). We also clarify the definition of this metric as suggested by SDG&E and focus the metric’s description on the number of “Priority Level 2” notifications that were completed on time divided by the total number of Priority Level 2 notifications that were due in the calendar year in the HFTDs. We indicate that reporting should be consistent with GO 95 Rule 18 provisions, that is, reporting should exclude notifications that qualify for extensions under reasonable circumstances. This metric is useful as it gives visibility to a utility’s compliance with electric safety regulations and the utility’s promptness to correct deficiencies within an acceptable timeframe.
 - SPM #44: Gas Overpressure Events: We adopt this metric as proposed by Staff. Gas overpressure events pose significant safety risks and can arise from incorrect operations, faulty design, or faulty equipment.
 - SPM #45: Gas In-Line Inspections Missed: We slightly modify the description of this metric to specify reporting

- according to the intervals established pursuant to 49 CFR, Part 192. Since inline inspections are an important pipeline risk assessment tool, this metric measures how well a gas operator is complying with inline inspection requirements.
- SPM #46 (SPM #32 in Appendices B and E): Overhead Conductor Safety Index: We modify Staff's proposed SOM #3.1 and Staff's proposed revised SPMs #s 1 and 2 and adopt these concepts as a new SPM. As discussed regarding SOM #3.1 and SPDs #s 1 and 2, the five conditions comprising this index are intended to capture a broader array of potentially significant safety risks posed by high voltage overhead conductors than the wires down definition alone can capture. This metric uses the definitions and concepts that had been included in Staff's proposed SOM #3.1 for PG&E on Wires Down, with the exception that we modify Staff's proposed definition of conductors that had referenced GO 95, as adopting this approach would have produced a disproportional number of occurrences within this index. Additionally, we apply these concepts to all electric IOUs. D.19-04-020 directed Staff to propose an electric overhead conductor index, and this metric fulfills this need.

We concur with commenters that several of Staff's proposed SPMs were not yet sufficiently defined or could have unintended consequences as worded. Thus, we do not adopt Staff's proposed SPMs #s 27, 28, 29, 31, 32, 34, 36, 37, 38, 39, 40, or 42. We also do not adopt Cal Advocates proposed new SPM #s 27.1, 41.1, or 43.1 as unnecessary and poorly defined. Our final adopted SPMs are listed in Appendix B.

We direct the IOUs to submit SPMs reports addressing the SPMs listed in Appendix B according to the method set forth in D.19-04-020, Ordering Paragraphs 1, 2, 3, and 6, with two modifications: the IOUs shall each serve and file their SPM reports in R.20-07-013, and their most recent or current RAMP and

GRC proceedings and shall concurrently send their SPM reports to the Director of the Safety Policy Division and to the RSA_Email@cpuc.ca.gov.

12. R.20-07-013 Technical Working Group

This decision formally establishes a R.20-07-013 TWG. This TWG will address RDF Proceeding issues as directed in this decision in sections 6.4, 7.3, 8.3, 9.1.4, 9.2.2, and 10.4.2. We summarize the scope of work of the TWG here.

The Phase I, Track 1 working group has been discussing methods to reflect foundational program costs in mitigation RSEs. Although this decision adopts requirements in this area, we also encourage the TWG to identify potential opportunities to test TURN's suggested "multi-portfolio" approach as described in section 6 using a small number of use-cases to understand the scope of work involved and to allow for an assessment of the quality of the results.

Some of the unanswered questions that could be explored by the TWG in a test of TURN's suggested approach, as discussed in section 6.4, include:

- How should the IOUs apply the different RSEs from the different combinations of mitigations and associated foundational activities into a logical decision-making framework to justify the selection of mitigations and foundational activities presented in the RAMP applications?
- How should the IOUs incorporate consideration of alternative mitigations and alternative foundational activities into the decision-making framework when foundational activities are involved?
- Should a reporting template be developed to ensure uniform treatment and uniform reporting of foundational activities and the associated RSEs?

As discussed in Section 7.3, the Phase I, Track 1 working group has been discussing potential methods for the IOUs to quantify safety impacts on customers from PSPS events to improve how PSPS events as risk events are

modeled in the RDF. The TWG shall continue to discuss questions surrounding modeling of PSPS events in the RDF. If Staff and/or parties develop a proposal providing more detailed guidance on this topic, the Assigned ALJ and Commissioner will provide this for party comment and consideration in a future decision in this proceeding.

Section 8.1 notes that PG&E intended to explore using the power law distribution function to model wildfire risk consequences and share its findings with the Track 1 working group in September of 2021, which PG&E did. Section 8.3 adopts Staff's proposal deferring requiring or recommending use of the power law probability distribution as an MAVF best practice at this time. Section 8.3 nonetheless directs Staff to continue to monitor the IOU's wildfire modeling practices as part of Staff reviews of IOU RAMP filings. Further, we direct Staff, if appropriate, to work with the TWG to provide a follow up recommendation on this topic as early as Phase II of this proceeding, if feasible. TWG discussions in this area shall include UCAN's suggestion regarding more accurate modeling of the location of customer assets in wildfire models. Any best practice for wildfire modeling must produce a set of consequences for wildfires that sufficiently incorporate high-end losses. We will continue to examine this issue in Phase II as part of exploring better ways for climate change risks, impacts, and uncertainties to be reflected in the RDF.

In Section 9.1.4, we agree with Staff that Cal Advocates' additional proposals to refine the PG&E Transparency Proposal should be considered in future phases of this proceeding, if feasible, including as early as Phase II, after SCE has served the completed transparency test drive documents. We authorize SPD Staff to convene discussions on the PG&E Transparency Proposal, and SCE's test drive of the proposal, as part of the Track 1 TWG moving forward. As

part of this, the TWG should discuss Cal Advocates' proposal, any lessons learned from the Risk Quantification Framework included in SDG&E and SoCalGas's most recent RAMP filing and parties' feedback on the framework. The TWG should also discuss the desirability, and, if so, methods to develop an appropriate set of estimate ranges to use in sensitivity calculations, as suggested by PG&E. We request Staff provide an updated Transparency Proposal for our consideration during Phase II of this proceeding, or at a later date, as appropriate.

In Section 9.2.2, we agree with Staff that methods to model climate risks, impacts and uncertainties is a topic worthy of consideration in Phase II of this proceeding, as long as this does not duplicate work being undertaken in R.18-04-019 *Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change*, which addresses climate change adaptation issues. However, Phase II of this proceeding already includes a long list of potential issues in scope. Therefore, we direct Staff and parties participating in the R.20-07-013 TWG to work to prepare an updated "S-MAP Roadmap" and a high-level workplan that indicates priorities and any dependencies for Phase II work and outlines approximate timelines and deliverables needed to address prioritized items. To the extent possible, this should be a consensus-based document, but non-consensus areas may be indicated as needed.

Staff and parties should aim to complete this work by December 31, 2021, or a later date as directed by the Assigned ALJ. The draft Roadmap may be served and filed as joint proposal from two or more parties or may be presented to the Assigned ALJ as a Staff proposal. The Assigned ALJ and Commissioner will request party comment on the draft Roadmap, when developing the Scoping

Memo for Phase II, as appropriate. A subsequent decision in Phase II may consider adopting such a roadmap.

Section 10.4.2 does not adopt Cal Advocates' recommendation to immediately establish a new working group to develop a framework to move towards specific thresholds and targets for PG&E's SOMs. However, we note that Staff and parties involved in the TWG established in this decision may examine this issue over time as data become available and experience is gained, as feasible given other R.20-07-013 priorities, and may bring to our attention any recommendation for formal triggering event thresholds or targets that they subsequently develop.

13. Environmental and Social Justice Action Plan

In 2018, the Commission adopted an *Environmental and Social Justice Action Plan* (ESJA Plan).¹⁷⁵ The Plan identifies Environmental and Social Justice (ESJ) communities as those where residents are predominantly communities of color or low-income, underrepresented in the policy setting or decision-making process, subject to a disproportionate impact from one or more environmental hazards, and/or likely to experience disparate implementation of environmental regulations and socio-economic investments in their communities. More specifically, the ESJA Plan identifies ESJ communities as including the top 25 percent of disadvantaged communities in California,¹⁷⁶ all California Tribal lands, low-income households with household income below 80 percent of area

¹⁷⁵ California Public Utilities Commission Environmental and Social Justice Action Plan (Commission ESJA Plan). V. 1.0, February 21, 2019, available here as of June 28, 2021: <https://www.cpuc.ca.gov/ESJactionplan/>.

¹⁷⁶ As identified by Cal EPA's CalEnviroScreen, available here as of June 28, 2021: <https://oehha.ca.gov/calenviroscreen>.

median income, and low-income census tracts with household incomes less than 80 percent area or state median income.¹⁷⁷

The Commission's ESJA Plan is guided by the following definition of environmental and social justice:

Environmental and social justice seeks to come to terms with, and remedy, a history of unfair treatment of communities, predominantly communities of people of color and/or low-income residents. These communities have been subjected to disproportionate impacts from one or more environmental hazards, socio-economic burdens, or both. Residents have been excluded in policy setting or decision-making processes and have lacked protections and benefits afforded to other communities by the implementation of environmental and other regulations, such as those enacted to control polluting activities.¹⁷⁸

The Scoping Memo indicated that Phase I may include assessing impacts on environmental and social justice communities, including the extent to which actions in this proceeding impact achievement of any of the nine goals of the ESJA Plan.¹⁷⁹

Phase I working groups did not explicitly consider the ESJA Plan and goals in their work. However, several ESJA Plan goals relate to this proceeding:

- Goal 4: Increase climate resiliency in ESJ communities: Disadvantaged communities comprise a small percent of the territory in PG&E's Tier 2 and Tier 3 HFTDs, likely less than five percent, although this estimate may not accurately reflect the number of tribal communities residing in these areas. The percentage of PG&E Tier 2 and

¹⁷⁷ ESJA Plan at 9.

¹⁷⁸ *Id.* at 6.

¹⁷⁹ Scoping Memo at 3. *See also* Commission Environmental and Social Justice Action Plan, available here as of August 18, 2021: <https://www.cpuc.ca.gov/news-and-updates/newsroom/environmental-and-social-justice-action-plan>.

Tier 3 HFTDs where the full spectrum and range of types of ESJ communities predominate is not yet well understood. Nonetheless, adopting SOMs and SPMs centered on PG&E and other IOUs' Tier 2 and Tier 3 HFTDs indirectly benefits disadvantaged and ESJ communities living in these areas by strengthening safety oversight efforts.

- Goal 5: Enhance outreach and public participation opportunities for ESJ communities to meaningfully participate in the CPUC's decision-making process and benefit from CPUC programs: Thus far, Commission Staff have not conducted outreach to engage ESJ communities on this proceeding. Therefore, we encourage Staff to brief the Commission's Disadvantaged Communities Advisory Committee on R.20-07-013 issues by June 1, 2022. We also encourage Staff to meet with organizations that represent persons with access and functional needs to discuss ways to improve how this proceeding considers issues relevant to this community in Phase II.
- Goal 6: Enhance enforcement to ensure safety and consumer protection for all, especially for ESJ communities: This decision implements safety and operational metrics for use in the EOE Process for PG&E and further refines Commission efforts to assess the safety performance of all IOUs. This decision supports improvement of RDF processes to identify risks and appropriately rank risk mitigations through the technical modifications addressed in Track 1.

14. Comments on Proposed Decision

The proposed decision of Commissioner Clifford Rechtschaffen in this matter was mailed to the parties in accordance with Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on October 7, 2021 by TURN, Cal Advocates, MGRA, PCF, SDG&E/SoCalGas, and PG&E, and reply comments were filed on

October 12, 2021 by SCE, PG&E, TURN, MGRA, Cal Advocates, SDG&E/SoCalGas, and PCF.

The final decision has been modified to reflect party comments and to add minor clarifications as follows:

1. PG&E correctly comments that the summary of RDF requirements adopted in the SA Decision contained some inaccuracies, which we correct in section 1.
2. SCE requests further clarifications on the “subcategories” of controls and mitigations, which we provide in section 5.1.
3. SDG&E/SoCalGas observe that our adopted definition of foundational programs and/or activities should indicate that these may address two or more risks in addition to addressing two or more mitigations. We make this change in sections 6 and 6.3 and in Appendix D.
4. SCE comments that the proposed decision inaccurately characterizes SCE’s 2020 WMP PSPS analysis. We correct this in the final decision in section 7.3.
5. SCE requests additional time to prepare the transparency test documents we require here. We modify sections 9 and 9.1.4 and Ordering Paragraph 3 to direct SCE to submit the required transparency test documents no later than 60 days from the date that SCE files its 2022 RAMP application and clarify that SCE shall serve these documents to the SCE 2022 RAMP proceeding service list.
6. PG&E requests clarification regarding the timeframes that its SOMs reports should cover. We clarify in section 10.4.4 and Ordering Paragraph 5 that PG&E shall submit its semi-annual SOMs reports

every March and September starting March 31, 2022, with each annual March report covering the 12-month period of the previous calendar year (*i.e.* January - December) and each annual September report providing data from January through June of the current year.

7. Regarding the required one and five-year targets for SOMs adopted in Section 10.4.4 (presented in Section 10.4.2), PG&E comments that directional targets are more appropriate than numerical targets for adopted SOMs based on MEDs and Red Flag Warning Days. We agree and modify sections 2.5.2.3.3 and 2.5.3.1.3 and Ordering Paragraph 5 to authorize PG&E, if it wishes, to propose directional targets (*i.e.* targets that do not consist of numerical values) that consider exogenous factors such as extreme weather events for the final adopted SOMs as listed in Appendix 1: SOM #2.3 (#2.11 as proposed) System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Major Event Days), SOM # 3.1 Wires Down Major Event Days in HFTD Areas (Distribution), SOM # 3.3 Wires Down Major Event Days in HFTD Areas (Transmission), SOM # 3.5 Wires Down Red Flag Warning Days in HFTD Areas (Distribution), and SOM # 3.6 Wires Down Red Flag Warning Days in HFTD Areas (Transmission). MEDs and Red Flag Warning Days are currently excluded from many utility reporting requirements. This makes it challenging to specify a number or rate of wire down incidents that could be seen as acceptable at present, (*i.e.* that could comprise the basis of numerical targets). However, PG&E equipment must show greater resiliency to both MEDs and Red Flag

Warning Days over the longer-term, even if there is some volatility year-to-year due to the uncertain nature and severity of these types of events. Authorizing PG&E to propose directional targets for these SOMs strikes a reasonable balance between this aim and current data constraints.

8. PG&E comments that SOM # 5.1 on Clean Energy Goals should be limited to PG&E's minimum procurement obligation assigned to its bundled service customers because direct access load serving entities may have elected to opt-out of or failed to reach their own separate procurement obligations. PG&E also recommends we remove the phrase "zero-emitting" from the definition of the metric because D.19-11-016 does not include this term in its mandate. The final decision modifies section 10.5.6 and Appendices A and E to remove the phrase "zero-emitting," but does not expressly limit reporting obligations to PG&E's bundled customers. PG&E's procurement obligations are specified in Commission decisions so we do not need to define those here.
9. In response to comments from SCE on SOM #3.12 (Electric Emergency Response Time), we modify this SOM in the final Appendices A and E to broaden the definition of emergency notifications to include calls made directly to the utilities' safety hotlines, not just 911 calls. We make the same change to SPM #s 3 (Electric Emergency Response Time) and 11 (Gas Emergency Response) in Appendices B and F.
10. SDG&E and SoCalGas note an error in the definitions of SPM #s 8 (Gas Shut-In Time, Mains) and 9 (Gas Shut-In Time, Services) in

Appendices B and F, which we correct so that these metrics now measure only uncontrolled or unplanned gas releases. We similarly modify SOMs #s 4.4 (Gas Shut-In Time, Mains) and 4.5 (Gas Shut-In Time, Services) in Appendices A and E to address the same issue.

11. SCE and SDG&E/SoCalGas correctly observe that the proposed decision incorrectly states that we eliminate a SPM relating to Days Away, Restricted and Transfer (“DART”) Rate. We modify the final decision to state that we eliminate SPM #14 relating to Employee SIFs because we adopt a new Rate of SIF Actual (Employee) that is substantially similar. We address this in section 11.3.2.
12. Regarding adopted SPMs #s 15 – 16, Rate of SIF Actual (Employee) and Rate of SIF Actual (Contractor) (SPM #s 17 – 18 as proposed), and adopted SPMs #s 17 – 18, Rate of SIF Potential (Employee) and Rate of SIF Potential (Contractor), SDG&E /SoCalGas’s comments persuade us that it is acceptable to allow the IOUs to use slightly different methodologies to report on these metrics. We continue to generally require utilities to use the EEI Occupational Health and Safety Committee methodology. However, the final decision also allows a utility to use a “substantially similar” and replicable methodology with the requirement that the utility explain how its methodology differs from the EEI methodology, and why it chose to use it, accompanied by supplemental reporting by all utilities. The final decision requires all IOUs to submit, as supplementary information, SIF Actual data based on OSHA reporting requirements under Section 6409.1 of the California Labor Code. This is necessary to ensure the Commission can accurately compare

utilities' performance on this metric. We discuss these changes in sections 11.3.2 and 11.4.2 and in explanatory text in Appendices B and F. Adopting this approach means that the final decision no longer provides SDG&E/SoCalGas with additional time to report on these metrics, resulting in the deletion of Conclusion of Law 25 and the last sentence of Ordering Paragraph 8.

13. Regarding SPM #27 (#35 as proposed), Overhead Conductor Size in HFTD Tiers 2 and 3, which SCE comments on, we clarify our rationale for this metric in section 11.4.2 and Appendices B and F, namely that tracking the percentage of overhead primary conductors smaller than #2 and #4 copper conductors will help measure of the amount of small primary distribution overhead conductors most prone to failure. Since #6 copper conductors are smaller and more prone to failure than #2 or #4 copper conductors, this is a suitable reference size to track for SPM #35. We further clarify that the suitability of #6 copper as a reference size for small overhead primary distribution conductors most prone to failure can be revisited in the future.
14. Regarding SPM # 28 (#41 as proposed), Gas Operation Corrective Actions Backlog, PG&E and SDG&E/SoCalGas recommend we modify the definition slightly to make it more precise. We address this in Appendices B and F.
15. The final decision slightly revises two gas dig-in metrics to assist with clarity. We modify SOM # 4.1 (Gas Dig-in) and SPM # 5 (Gas Dig-in) to exclude Underground Service Alert tickets generated by a utility or its contractors, which, if included in the denominator of

these metrics reduce the measurement of dig-ins without adding visibility to our main area of concern, which centers on third-party dig-ins. These changes are reflected in section 11.3.2 and in Appendices B and F, which summarize our adopted SPMs.

16. The final decision clarifies in Appendices A and E that required reporting on Electricity Related SOMs (SOMs #s 3.1 – 3.12) and Ignitions and Wildfires Related SOMs (SOMs #s 3.13 – 3.16) that contain HFTDs is limited to Tier 2 and Tier 3 HFTDs. This issue is discussed extensively in sections 10.5.2.3.3 and 10.5.3.1.3. We make this change to avoid any future confusion and to align the explanatory text for these SOMs with that in place for System Average Outages due to Vegetation and Equipment Damage in HFTDs (SOM #s 2.3 and 2.4) in the same appendices.

We note two comments that did not result in changes to the final decision. First, SCE comments that parties had limited opportunity to address revisions to some of our final adopted SPMs. We disagree. The SPMs included in the proposed decision were based on extensive working group and Staff discussions and parties also had the opportunity to comment on the SPMs in their comments on the proposed decision. Further, as extensively discussed here, the final decision revises some of the SPMs based on parties' comments.

Second, regarding the PG&E transparency proposal, TURN requests that we require SCE to also test TURN's transparency proposal. We do not require this in the final decision but note that Rule 10.1 of the Commission Rules of Practice and Procedure require utilities to respond to reasonable discovery data requests, including, for instance, a discovery request by TURN that SCE complete a TURN transparency matrix.

15. Assignment of Proceeding

Clifford Rechtschaffen is the Assigned Commissioner and Cathleen A. Fogel is the Assigned ALJ in this proceeding.

Findings of Fact

1. It is reasonable to clarify technical aspects of the Settlement Agreement adopted in D.18-12-014 to support the goals of the Risk, S-MAP and RDF Proceedings to ensure transparency and utility accountability regarding assessment and mitigation of safety risks.
2. The IOUs have used a variety of methods to distinguish mitigation measures in their RAMP applications, including controls, that are “currently established” or “in place” from those that are new.
3. The SA Decision does not define foundational programs or activities that support or enable utility mitigation programs but do not directly reduce safety risks.
4. Examples of foundational programs or activities may include software and computer hardware resources, situational awareness initiatives such as weather modeling, and vehicles used by employees.
5. Requiring the IOUs to use the thresholds adopted for the RSARs to include foundational costs in their mitigation RSEs adds clarity and consistency while allowing for variation based on company size.
6. It would be useful to test TURN’s suggested “multi-portfolio” approach to explore if this brings greater clarity to the inclusion of foundational program costs in mitigation RSEs.
7. OEIS WMP Guidelines require analysis of PSPS impacts.

8. SCE and SDG&E modeled the probability and consequences of both wildfire and PSPS events in their 2021 WMPs, and SDG&E and SoCalGas's 2020 RAMP applications include a basic treatment of PSPS risks and consequences.

9. Requiring the IOUs to explicitly incorporate PSPS risks and consequences into the RDF and their RAMP filings, subject to the provisions of the SA Decision, will advance consideration of the impacts of these events on customers.

10. Directing SCE to test the PG&E Transparency Proposal as modified here and directing SCE to serve the transparency documents, completed to the best of its ability, no later than 60 days from the date SCE files its 2022 RAMP filing will help the Commission and parties to refine transparency measures beyond those required in the SA Decision.

11. It is reasonable to clarify that this decision directs SCE to complete the transparency guidelines templates only to the best of its ability and that the Commission will consider the test results as purely informational, and to ask Staff to support SCE's completion of this task in a way that does not disrupt SCE's RAMP preparations.

12. A distinguishing feature of wildfire size and consequences following power law behavior is that extreme events dominate the results, which is consistent with the recent California wildfires of historical proportions.

13. It is essential that the modeling methods used by IOUs in their RDFs, WMPs, and RAMPs produce a set of consequences for wildfire that sufficiently incorporate high-end losses.

14. The topic of climate change impacts, risks and mitigation measures is worthy of consideration in Phase II of this proceeding, but the issue is best considered as part of a larger Roadmap development process to help guide Phase II of this proceeding as there are already many issues in scope.

15. Staff's proposed SOMs reporting requirements and evaluation methods are consistent with Commission's direction in D.20-05-053 and are reasonable, with the modification that PG&E report SOMs on a semi-annual rather than an annual basis.

16. It is reasonable to authorize PG&E to, in this or a successor proceeding, serve and file a request to modify the semi-annual frequency of SOMs reporting adopted here five years from issuance of this decision and to provide a rationale for this request if it does so.

17. Because of PG&E's role in creating the safety issues that led to the EOE Process and the adoption of SOMs, it is reasonable to require an independent audit of PG&E's collection and management of SOMs data and to require PG&E shareholders to pay for the audit.

18. PG&E's SOMs proposal was incomplete, but the more comprehensive Staff SOMs Proposal incorporates many of PG&E's suggested SOMs, some in modified form.

19. Adopting a PG&E SOM on SIFs Actual (Public) adds a comprehensive view of PG&E's safety performance and is appropriate to use in relation to PG&E executive compensation determinations.

20. It is appropriate to recategorize Staff's proposed Rate of SIF Potential SOMs to Rate of SIF Potential SPMs as it is detrimental to penalize a utility for reporting potentially hazardous conditions and an increase in SIF Potential incidents could either indicate improved reporting or an increase in the number of potentially hazardous conditions.

21. Because PSPS events have the dual potential of both mitigating and aggravating safety risks, adopting PSPS related SOMs for enforcement purposes at this time sends a mixed message at best and/or the wrong signal at worst.

22. PG&E has a duty under Section 451 and Rule 31.1 to design, build, and maintain facilities based on known local wind conditions.

23. While weather events are important drivers of risk events, they are not determinative of outcomes, and it is exactly under strong weather conditions that PG&E's preparedness and operational capacity have the greatest impact on public safety.

24. The Staff SOMs Proposal as modified here is reasonable and aligns with the criteria set forth in the SOMs Ruling.

25. SDG&E and SoCalGas do not currently use the EEI methodology to gather data on employee or contractor SIFs.

26. The Staff SPM Proposal as modified here is reasonable and aligns with the criteria proposed by SDG&E/SoCalGas as discussed in Section 11.3.1.

Conclusions of Law

1. Public Utilities Code Section 750 requires the Commission to develop formal procedures to consider safety in a rate case application by an electrical corporation or gas corporation.

2. Public Utilities Code Section 321.1(a) requires the Commission to assess and mitigate the impacts of its decisions on customer, public and employee safety.

3. Public Utilities Code Section 451 requires the Commission to ensure that electric and gas utilities adopt just and reasonable rates.

4. The Commission should require the IOUs to each and as a group consistently and uniformly define and treat all forms of mitigations, including control measures and any and all subcategories of control measures, in their RDFs and RAMP filings, and in related filings in other proceedings.

5. The Commission should require the IOUs to evaluate all mitigations for efficacy and efficiency, whether the mitigation is “in process” or newly proposed, when using the RDF and in all RAMP filings.

6. The Commission should require the IOUs to calculate RSEs for all mitigations, including controls that are ongoing.

7. The Commission should require the IOUs to establish baselines for mitigation measures as follows and should add the terms “baselines” and “baseline risk” to the 2021 S-MAP Revised Lexicon included in Appendix D:

The baseline is a reference point in time at the start of the new GRC cycle. The baseline risk as applied to RAMP and GRC proceedings refers to the amount of residual risk evaluated at the baseline (*i.e.* at the start of the new GRC cycle) after taking into account all risk reduction benefits from all risk mitigation activities projected to have been performed by the start of the new GRC cycle. The projected risk mitigation activities include those that are classified by the IOUs as controls, as well as all mitigation activities for which the IOUs are seeking approval and/or funding in the current or upcoming RAMP and GRC applications.

8. The Commission should revise the definition of “residual risk” in the 2021 S-MAP Revised Lexicon as follows: “risk remaining after ~~current controls~~ application of mitigations, including mitigations classified as controls.”

9. The Commission should require each IOU to identify in its annual RSAR the costs for controls and/or mitigation measures and/or activities that were approved in prior GRC cycles but not implemented, as applicable.

10. The Commission should define foundational programs and activities as “initiatives that support or enable two or more mitigation programs or two or more risks but do not directly reduce the consequences or reduce the likelihood

of risk events,” and add this term and definition to the 2021 Revised S-MAP Lexicon contained in Appendix D to this decision.

11. The Commission should clarify that in case of conflict with the new terms and definitions adopted in this decision with other usages of these terms for the purposes of this proceeding, the revised or new definitions adopted here supersede those other usages and definitions.

12. The Commission should require the IOUs to include the costs of foundational programs and activities in mitigation RSEs if the foundational program / activity costs exceed the thresholds adopted for the RSARs in D.19-04-020 and should authorize IOUs to include foundational costs below these thresholds on an optional basis.

13. The Commission should require the IOUs to incorporate the costs of foundational elements into the RSEs they present in their next RAMP filing, to explain and justify their chosen distribution of foundational costs to mitigations, and to comply with applicable requirements of the SA Decision to explain their rationale and assumptions in categorizing foundational costs clearly and transparently.

14. The Commission should require the IOUs to model PSPS events as risk events in the RDF and in future RAMP filings, including assessing the likelihood and consequences of PSPS events.

15. The Commission should establish an R.20-07-013 TWG led by Staff to address RDF Proceeding issues, and should authorize Staff and parties to:

- a. Identify potential opportunities and, if appropriate, begin to test TURN’s suggested “multi-portfolio” approach to reflecting foundational costs in mitigation RSEs in a small number of use-cases, including exploring questions such as:

- i. How should the IOUs apply the different RSEs from the different combinations of mitigations and associated foundational activities into a logical decision-making framework to justify the selection of mitigations and foundational activities presented in the RAMP applications?
 - ii. How should the IOUs incorporate consideration of alternative mitigations and alternative foundational activities into the decision-making framework when foundational activities are involved?
 - iii. Should a reporting template be developed for uniform treatment and uniform reporting of foundational activities and the associated RSEs?
- b. Continue discussing better methods to model PSPS events in the RDF, providing a proposal for more detailed Commission guidance on this topic, as early as Phase II of this proceeding, if feasible and deemed useful by Staff;
- c. Discuss PG&E's test of the power law distribution approach to modeling wildfire risk, and other approaches, with the goal of determining the need for and, if so, identifying one or more MAVF best practices for modeling wildfire risk and consequences that properly capture increasing wildfire risk due to climate change;
- d. Discuss ways to further refine PG&E's Transparency Proposal as adopted here, as discussed in section 9.1.4, and provide an updated Transparency Proposal for consideration as early as Phase II of this proceeding, if feasible;
- e. Prepare and propose, as discussed in this decision, an updated draft "S-MAP Roadmap" and a high-level workplan for Phase II of this proceeding that indicates priorities and any dependencies and outlines approximate timelines and deliverables needed to address prioritized items, with the aim of completing this work by December 31, 2021, or a later date as directed by the assigned ALJ;

- f. As data become available and experience is gained, and as feasible given other R.20-07-013 priorities, discuss methods to move towards a possible framework for targets or thresholds for PG&E's SOMs; and,
- g. Begin work on priority elements identified in the Roadmap process ordered here.

16. The Commission should require SCE to test the PG&E Transparency Proposal, modified as indicated in Appendix C, and to serve the transparency documents to the SCE 2022 RAMP proceeding service list no later than 60 days from the date of SCE's 2022 RAMP filing.

17. The Commission should require Staff to support SCE in identifying ways for SCE to test PG&E's Transparency Proposal as appended here in a way that does not disrupt SCE's RAMP preparations.

18. The Commission should apply the SOMs adopted in this decision only to PG&E, for the purposes identified in D.20-05-053.

19. The Commission should adopt Staff's proposed SOM reporting requirements for PG&E and Staff's intended evaluation methods as discussed in Sections 10.4 and 10.5.1, except that the Commission should require PG&E to report the SOMs on a semi-annual rather than an annual basis.

20. The Commission should authorize PG&E to, in this or a successor proceeding, serve and file a request to modify the semi-annual frequency of SOMs reports required here after five years from issuance of this decision and should require it to provide a rationale for requesting this if it does so.

21. The Commission should undertake one independent, third-party audit of PG&E's SOMs data and data collection methods in the next three years, serve the audit findings to members of this service list, revisit the need for a more permanent independent third-party auditing system based on whether the audit

identifies significant discrepancies or concerns, and should require PG&E shareholders to pay for the audit.

22. The Commission should adopt the 32 SOMs as provided in Appendix A.

23. Our adopted SOMs may overlap with other triggering events included in the EOE Process adopted in D.20-05-053, the Commission's Enforcement Policy as updated in Resolution M-4846, enforcement aspects of the SPMs as discussed in D.19-04-020, and questions regarding PG&E compliance with California's GHG emissions reduction goals, other clean energy goals, OSHA rules, and other state laws and regulations.

24. The Commission should modify 15 existing SPMs adopted in D.19-04-020, delete four of the SPMs adopted in D.19-04-020, and should adopt 10 new SPMs as set forth in Appendix B.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric Company (SDG&E) (collectively investor-owned utilities or IOUs) shall implement the following in their Risk-Based Decision-Making Framework (RDF) and Risk Assessment Mitigation Phase (RAMP) filings:

- a. Each investor-owned utility (IOU), and the IOUs as a group, shall consistently and uniformly define and treat all forms of mitigations including control measures and all subcategories of control measures, including in related proceedings;
- b. Each IOU shall evaluate all mitigations for efficacy and efficiency, whether the mitigation is "in process" or newly proposed;
- c. Each IOU shall calculate Risk Spend Efficiencies (RSEs) for all mitigations, including controls that are ongoing;

- d. Each IOU shall establish baselines for mitigation measures as follows:

The baseline is a reference point in time at the start of the new General Rate Case (GRC) cycle. The baseline risk as applied to RAMP and GRC proceedings refers to the amount of residual risk evaluated at the baseline (*i.e.* at the start of the new GRC cycle) after taking into account all risk reduction benefits from all risk mitigation activities projected to have been performed by the start of the new GRC cycle. The projected risk mitigation activities include those that are classified by the IOUs as controls, as well as all mitigation activities for which the IOUs are seeking approval and/or funding in the current or upcoming RAMP and GRC applications;

- e. Each IOU shall include the cost of foundational programs in their mitigation RSE calculations if the aggregate cost over the upcoming GRC funding period of the foundational programs supporting a portfolio of risk mitigations exceeds the following:
- i. For PG&E and SCE, the lesser of \$10 million, or 20 percent of the cost of the portfolio of enabled mitigations, subject to a minimum of \$5 million for the percentage test;
 - ii. For SDG&E, for its electric and other operations, the lesser of \$5 million, or 20 percent of the cost of the portfolio of enabled mitigations, subject to a minimum of \$2.5 million for the percentage test;
 - iii. For SDG&E, for its gas operations, the lesser of \$2.5 million, or 20 percent of the cost of the portfolio of enabled mitigations, subject to a minimum of \$0.5 million for the percentage test; and,
 - iv. For SoCalGas, the lesser of \$5 million, or 20 percent of the cost of the portfolio of enabled mitigations, subject to a minimum of \$1 million for the percentage test;
- f. Each IOU shall identify in its annual Risk Spending Accountability Report (RSAR) the costs for controls and/or

- mitigation measures and/or activities that were approved in prior GRC cycles but not implemented, as applicable;
- g. Each IOU shall incorporate the costs of foundational elements into the RSEs they present in their next RAMP filing, shall clearly and transparently explain and justify their chosen distribution of foundational costs to mitigations, and shall comply with applicable requirements of Decision (D.) 18-12-014 to explain their rationale and assumptions in categorizing foundational costs; and,
 - h. Each IOU shall model Public Safety Power Shutoff (PSPS) events as risk events pursuant to requirements in D.18-12-014;
2. A Risk-Based Decision-Making Framework (RDF) Technical Working Group (TWG) led by Staff is established, and is authorized to:
- a. Continue discussing better methods to model Public Safety Power Shutoff (PSPS) events as risk events in the RDF, providing a proposal for more detailed Commission guidance on this topic as early as Phase II of this proceeding, if feasible and deemed useful by Staff;
 - b. Discuss Pacific Gas and Electric Company's (PG&E) test of the power law distribution approach to modeling wildfire risk, and approaches used by other utilities, with the goal of determining the need for and, if so, identifying one or more best practices for modeling wildfire risk and consequences that properly capture increasing wildfire risk due to climate change;
 - c. Discuss ways to further refine the PG&E Transparency Proposal as modified and discussed in Section 9.1.4, and provide an updated proposal for consideration as early as Phase II of this proceeding, if feasible;
 - d. Prepare and propose, as directed in this decision, an updated draft "Safety Model Assessment Proceeding (S-MAP) Roadmap" and a high-level workplan for Phase II of this proceeding that indicates priorities and any

dependencies and outlines approximate timelines and deliverables needed to address prioritized items, with the aim of completing this work by December 31, 2021, unless the Assigned Administrative Law Judge authorizes a later date;

- e. As data become available and experience is gained, and as feasible given other Rulemaking 20-07-013 priorities, discuss methods to move towards a possible framework for targets or thresholds for PG&E's Safety and Operational Metrics; and,
- f. Begin work on priority elements identified in the Roadmap process ordered here.

3. Southern California Edison Company (SCE) shall "test drive" the Pacific Gas and Electric Company Transparency Proposal, as modified here and contained in Appendix C, and shall serve the completed transparency documents to the SCE 2022 Risk Assessment and Mitigation Phase (RAMP) proceeding service list no later than 60 days from the date SCE files its 2022 RAMP report.

4. The Safety and Operational Metrics contained in Appendix A are adopted for application to Pacific Gas and Electric Company for the purposes outlined in Decision 20-05-053.

5. Pacific Gas and Electric Company (PG&E) shall report its Safety and Operational Metrics (SOMs) as follows. PG&E shall, on a semi-annual basis, serve and file its SOMs report in Rulemaking 20-07-013, any successor Safety Model Assessment Proceeding, and its most recent or current General Rate Case and Risk Assessment and Mitigation Phase proceedings starting March 31, 2022 and continuing annually at the end of September and March thereafter, with the March reports covering the 12 months of the previous calendar year (i.e., January through December) and the September reports providing data for January

through June of the current year. PG&E shall concurrently send a copy of its semi-annual SOMs reports to the Director of the Commission's Safety Policy Division and to RASA_Email@cpuc.ca.gov. PG&E shall:

- a. Report on each SOM, using data for the preceding 12 months and providing all available historical data;
- b. For each SOM, provide a proposed target for the year following the reporting period for each metric and a five-year target, with the proposed target represented as specific values, ranges of values, a rolling average, or another specified target value, except for our final adopted SOM #s 1.3, 2.3, 3.1, 3.3, 3.5, and 3.6 for which PG&E may provide directional targets;
- c. For each SOM, provide a narrative description of the rationale for selecting the target proposed and why a specific value, a range of values, a rolling average or another type of target is selected;
- d. For each SOM, provide a narrative description of progress towards the proposed annual and five-year targets;
- e. For each SOM, provide a narrative description of any substantial deviation from prior trends based on quantitative and qualitative analysis, as applicable;
- f. For each SOM, provide a brief description of current and future activities to meet the proposed targets; and,
- g. Provide the Commission's Safety and Policy Division with a copy of any report filed more frequently than semi-annually with the Commission that contains SOMs, at the same time the report is filed.

6. Pacific Gas and Electric Company (PG&E) is authorized to, in this or a successor proceeding, serve and file a request to modify the semi-annual frequency of Safety and Operational Metrics reporting adopted here after five years from issuance of this decision; PG&E shall provide a rationale for this request if it does so.

7. Pacific Gas and Electric Company (PG&E) shareholders shall pay for an independent third-party audit of PG&E's Safety and Operational Metrics (SOMs) data collection and reporting processes within the next three years to ensure accuracy and compliance with SOMs reporting requirements. We will select one of two options to secure an independent auditor. First, Staff may explore adding this scope of work to an existing auditor contract. Alternatively, PG&E shall undertake the solicitation process, but the Commission's Executive Director or her designee will make the final selection of auditing firm. Safety and Policy Division Staff will direct PG&E in drafting and issuing solicitation materials including a Request for Proposals (RFP). While PG&E will be involved with the RFP, the Commission's Executive Director or designee will have sole discretion to select the consultant from eligible candidates that responded to the RFP.

8. The Safety and Performance Metrics (SPMs) contained in Appendix B are adopted for application to Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company (SoCalGas), and San Diego Gas & Electric Company (SDG&E), as indicated, for annual reporting starting on March 31, 2022, with each report covering the previous 12-month period.

9. Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company (collectively investor-owned utilities) shall submit the Safety Performance Metrics (SPMs) listed in Appendix B according to the methods set forth in Decision 19-04-020, Ordering Paragraphs 1, 2, 3, and 6, with two modifications: the investor-owned utilities shall serve and file their SPM reports in Rulemaking 20-07-013, and their most recent or current Risk Assessment Mitigation Phase and General Rate Case proceedings, and shall concurrently email their SPM reports to RASA_Email@cpuc.ca.gov.

10. The 2018 Safety Model Assessment Proceeding (S-MAP) Lexicon is revised and adopted as indicated in the 2021 S-MAP Revised Lexicon included in Appendix D. In case of conflict with the new definitions for terms adopted in this decision with other usages of these terms for the purposes of this proceeding, the revised or new definitions adopted here supersede those other usages and definitions.

11. Rulemaking 20-07-013 remains open.

This order is effective today.

Dated _____, at San Francisco, California.

APPENDIX A:
Adopted Safety and Operational Metrics for
Application to PG&E

APPENDIX B:

Adopted Safety Performance Metrics

APPENDIX C:
PG&E Transparency Proposal as Modified

APPENDIX D:
2021 S-MAP Revised Lexicon

APPENDIX E:
Safety and Operational Metrics for Application to
PG&E, Redline

APPENDIX F:

Safety Performance Metrics, Redline

APPENDIX G:

Glossary of Terms