APPENDIX B

STAFF PROPOSAL ON SAFETY AND OPERATIONAL METRICS

& Recommendations on Phase I Track 2 Issues Outlined in the November 2, 2020 Assigned Commissioner's Scoping Memo and Ruling Issued in the Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities (R. 20-07-013)

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Executive Summary

The November 2, 2020 Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo) outlined issues to be considered in the Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities (RDF Proceeding).[1] The Scoping Memo stated that "Phase I and Phase II of this proceeding will draw on the experiences and lessons learned so far regarding requirements adopted in [Application] A.15-05-002 *et al* and [Rulemaking] R.13-11-006. Issues considered 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 Commission's Environmental and Social Justice Action Plan."[2]

Specifically, Phase I Track 2 of this proceeding considers safety, operational, and performance metrics and their broad application, including refining the safety performance metrics (SPMs) adopted in Decision (D.)19-04-020, and developing new metrics as needed, including the development of Safety and Operational Metrics (SOMs) for Pacific Gas and Electric Company's (PG&E) Enhanced Oversight and Enforcement (EOE) process, approved in D.20-05-053.[3]

The November 17, 2020 Assigned Commissioner's Ruling (ACR) directed Pacific Gas and Electric Company (PG&E) to propose SOMs suitable for use as Triggering Events as specified in the EOE process.[4] In response to the ACR, PG&E proposed 12 SOMs.[5] PG&E excluded electric overhead conductor metrics from its proposed SOMs, as directed in the ACR because these metrics were under development by the Safety Model Assessment Proceeding (S-MAP) Technical working group, pursuant to D.19-04-020.[6] In subsequent comments and reply comments, parties critiqued PG&E's proposals and suggested additional SOMs.[7]

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[1] *Assigned Commissioner's Scoping Memo and Ruling* of the Order Instituting Rulemaking (Scoping Memo) to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities (Rulemaking (R.) 20-07-013), November 2, 2020.

[2] Scoping Memo at 3.

[3] Scoping Memo at 3.

[4] *Assigned Commissioner's Ruling Regarding the Development of Safety and Operational Metrics*, November 17, 2020, at 1. Available here: November 17, 2020 ACR (R.20-07-013)

[5] January 15, 2021 Response of Pacific Gas and Electric Company to Assigned Commissioner's Ruling Regarding Development of Safety and Operational Metrics. Available here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M359/K864/359864708.PDF

[6] ACR at 4.

[7] Available here: R.20-07-013

The Safety Policy Division (SPD) staff (Staff) lunched a public workshop on January 28, 2021 where PG&E presented its proposed SOMs, followed by Technical Working Group (TWG) meetings to address Phase I Track 2 issues.

On April 22, 2021, following review of PG&E's proposed SOMs and party comments, Staff circulated a Draft Staff Proposal and requested informal comments from the TWG. The Draft Staff Proposal proposed a set of SOMs addressing PG&E's safety, reliability, and clean energy goals. The Draft Staff Proposal also included recommendations on modifying the adopted SPMs in D.19-04-020. Staff proposed SOMs are intended for use exclusively for PG&E's EOE Process, whereas Staff recommended modifications and additions to the adopted SPMs in D.19-04-020, apply to all IOUs. This document reflects SPD Staff's recommendations following consideration of discussion in the TWG and parties' informal comments on the Draft Staff Proposal.

Appendix C provides a summary of Staff's proposed SOMs and Appendix D provides a summary of Staff recommended modification/additions to adopted SPMs, developed pursuant to D.19-04-020.

Summary of Staff's Proposal on SOMs as EOE Triggering Events

D.20-05-053 approving PG&E's bankruptcy plan of reorganization established the EOE process allowing the California Public Utilities Commission (Commission) to take additional steps to ensure PG&E is improving its safety and operational performance as part of the decision approving the reorganization following the utility's bankruptcy if specified Triggering Events occur.[8]

That decision described 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."[9] In addition, D.20-05-053 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..."[10]

Following guidance outlined in the ACR, Staff developed its proposed SOMs to meet two primary objectives: (1) SOMs must be suitable for use as Triggering Events as specified in the EOE process approved in D. 20-05-053; and (2) SOMs should be suitable, over time, for the Commission, intervenors, and the public to gauge the safety and operational performance of all gas and electric IOUs.[11]

In selecting SOMs, Staff sought to identify metrics that are objective, outcome-based, defined clearly, auditable/verifiable, enforceable, measurable over time, and preferably,

[8] D.20-05-053, at Appendix A.

[9] D.20-05-053, at 38.

[10] D.20-05-053, at 96.

[11] ACR at 1-4.

leading indicators. Staff proposed SOMs cover a variety of topic areas including worker safety, electric reliability, ignitions, electric and natural gas systems' safety, quality of service, and clean energy goals. Staff also considered, but ultimately opted not to select metrics specific to PG&E's quality of management and affordability.[12]

Staff has selected SOMs that will serve as supplemental, cross-cutting tools in support of the Commission's existing oversight and enforcement activities. All SOMs are intended to serve the purpose of prompting PG&E to improve its safety and operational performance.

Staff recommends that PG&E report SOMs, including historical data, on an annual basis. As many of Staff's proposed SOMs are also reported to the Commission more frequently, such as on a quarterly basis, in compliance with other regulatory requirements, PG&E should provide a copy of those reports to SPD at the same time they are filed with the Commission.

Staff also recommends that PG&E, as part of their annual SOMs submittals, propose one-year and five-year targets for each of the metrics. PG&E should also include a narrative discussing its current and planned activities to achieve these targets.

Organization of the Document

Part I of this document responds to the issues raised in Phase I Track 2 of the Scoping Memo for R.20-07-013. It is primarily dedicated to the development and selection of SOMs 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, but also covers other questions.

Part II of the document includes proposed modifications and additions to the adopted SPMs in D.19-04-020.

Table 1 provides a summary of Staff proposed SOMs. Table 2 provides a summary of Staff recommended modification/additions to adopted SPMs in D.19-04-020.

[12] See sections 2.16 and 2.17

Table 1: Staff proposed SOMs.

Number Index	Staff Proposed SOMs	SPMs
1	SIF related SOMs	
1.1	Rate of SIF Actual (Employee)	√ *SPM 17*
1.2	Rate of SIF Actual (Contractor)	√ *SPM 18*
1.3	Rate of SIF Potential (Employee)	N/A
1.4	Rate of SIF Potential (Contractor)	N/A
2	Reliability Related SOMs	
2.1	System Average Sustained Interruption Duration (SAIDI) (Unplanned)	N/A
2.2	System Average Sustained Interruption Duration (SAIDI) (All Outages)	N/A
2.3	System Average Sustained Interruption Frequency (SAIFI) (Unplanned)	N/A
2.4	System Average Sustained Interruption Frequency (SAIFI) (All Outages)	N/A
2.5	Customer Average Sustained Interruption Duration Index (CAIDI) (Unplanned)	N/A
2.6	Customer Average Sustained Interruption Duration Index (CAIDI) (All Outages)	N/A
2.7	System Average Customers Impacted (All Outages)	N/A
PSPS Related SOMs		
2.8	Number of PSPS events in a calendar year	N/A
2.9	Duration of each PSPS Event in hours in a calendar year	N/A
2.10	Number of Customers Impacted by each PSPS Event in a calendar year	N/A
System Average Outages due to Vegetation and Equipment Damage in HFTD Areas		
2.11	System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Major Event Days)	N/A

Number Index	Staff Proposed SOMs	SPMs
2.12	System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Non-Major Event Days)	N/A
3	Electricity Related SOMs	
Wires Down Related SOMs		
3.1	Wires Down Major Event Days in HFTD Areas	√ *SPM #2*
3.2	Wires Down Non-Major Event Days in HFTD Areas	√ *SPM #1*
3.3	Wires Down Red Flag Warning Days in HFTD Areas	N/A
Patrols, Inspections & Compliance Related SOMs		
3.4	Overhead Distribution Patrols in HFTD Areas	√ *SPM #33*
3.5	Overhead Distribution Detailed Inspections in HFTD Areas	√ *SPM #33*
3.6	Overhead Transmission Patrols in HFTD Areas	√ *SPM #33*
3.7	Overhead Transmission Detailed Inspections in HFTD Areas	√ *SPM #33*
3.8	Distribution Vegetation Line Clearance Inspections in HFTD Areas	√ SPM #34
3.9	Transmission Vegetation Line Clearance Inspections in HFTD Areas	√ SPM #34
3.10	Backlog Compliance Metrics in HFTD	√ SPM #42
3.11	Electric Emergency Response Time (Proposed by PG&E)	√ *SPM #3*
Ignitions & Wildfires Related SOMs		
3.12	Number of CPUC-Reportable Ignitions in HFTD Areas (Distribution)	√ *SPM #4*
3.13	Percentage of CPUC-Reportable Ignitions in HFTD (Distribution)	N/A
3.14	Number of CPUC-Reportable Ignitions in HFTD (Transmission)	N/A

Number Index	Staff Proposed SOMs	SPMs
3.15	Percentage of CPUC-Reportable Ignitions in HFTD (Transmission)	√ *SPM #4*
4	**Natural Gas Related SOMs**	
4.1	Number of Gas Dig-Ins per 1000 USA tickets on Transmission and Distribution pipelines	√ *SPM #5*
4.2	Number of Overpressure (OP) Events	√ *SPM #44*
4.3	Normalized Overpressure Events	N/A
4.4	Time to Respond On-site to Emergency Notification	√ *SPM #11*
4.5	Gas Shut-In Time, Mains	√ *SPM #8*
4.6	Gas Shut-In Time, Services	√ *SPM #9*
4.7	Uncontrolled Release of Gas on Transmission Pipelines	N/A
4.8	Time to Resolve Hazardous Conditions	N/A
5	**Clean Energy Goals**	
5.1	Clean Energy Goals Compliance Metrics	N/A

Table 2: Staff Recommended Modification/Additions to Adopted SPMs in D.19-04-020.

Number Index	Staff Proposed SPMs	IOUs Required to Report
Recommended Modifications to Selected Metrics of the 26 Adopted SPMs in D.19-04-020		
1.	Wires Down Non-Major Event Days	PG&E, SCE, SDG&E, SoCalGas
2.	Wires Down Major Event Days	PG&E, SCE, SDG&E, SoCalGas
5.	Gas Dig-in	PG&E, SDG&E, SoCalGas
6.	Gas In-Line Inspection	PG&E, SDG&E, SoCalGas
7.	Gas In-Line Inspection Upgrade	PG&E, SDG&E, SoCalGas
8.	Gas Shut-In Time – Mains	PG&E, SDG&E, SoCalGas
9.	Gas Shut-In Time – Services	PG&E, SDG&E, SoCalGas
10.	Cross-Bore Intrusions	PG&E, SDG&E, SoCalGas
11.	Gas Emergency Response	PG&E, SDG&E, SoCalGas
12.	Natural Gas Storage	PG&E, SDG&E, SoCalGas
13.	Gas System Internal Inspection Status	PG&E, SDG&E, SoCalGas
14.	Employee Serious Injuries and Fatalities	PG&E, SCE, SDG&E, SoCalGas
17.	Employee OSHA Recordables Rate	PG&E, SCE, SDG&E, SoCalGas
18.	Contractor OSHA Recordables Rate	PG&E, SCE, SDG&E, SoCalGas

Number Index	Staff Proposed SPMs	IOUs Required to Report
Recommended Additions to the 26 Adopted SPMs in D.19-04-020		
27.	Median Time to Correct Inspection Findings (Tiers or Grades)	PG&E, SCE, SDG&E, SoCalGas
28.	Median Time to Correct Inspection Findings	PG&E, SCE, SDG&E, SoCalGas
29.	CPUC-Reportable Overhead Conductor Failure Incidents Excluding Media Attention	PG&E, SCE, SDG&E, SoCalGas
30.	Wires Down Remaining Energized	PG&E, SCE, SDG&E
31.	Wires Down Root Cause Analysis	PG&E, SCE, SDG&E
32.	Wires Down by Cause	PG&E, SCE, SDG&E
33.	Missed Inspections and Patrols for Electric Circuits	PG&E, SCE, SDG&E
34.	Missed Vegetation Management Inspections	PG&E, SCE, SDG&E
35.	Overhead Conductor Wire Size Compliance in HFTD Areas	PG&E, SCE, SDG&E
36.	Overhead Conductor Wire Size Compliance in non-HFTD Areas	PG&E, SCE, SDG&E
37.	Infrared Inspections on Electric Distribution Circuits in HFTD Areas	PG&E, SCE, SDG&E
38.	System Hardening in HFTD Areas	PG&E, SCE, SDG&E
39.	System Undergrounding in HFTD Areas	PG&E, SCE, SDG&E
40.	Enhanced Vegetation Management (EVM) Work Completed	PG&E, SCE, SDG&E
41.	Work Order Backlog	PG&E, SCE, SDG&E, SoCalGas
42.	Electric Work Order Backlog in HFTD Areas	PG&E, SCE, SDG&E
43.	GO-95 Corrective Actions in HFTD Areas	PG&E, SCE, SDG&E
44.	Gas Overpressure Events	PG&E, SCE, SDG&E
45.	Gas In-Line Inspection Interval	PG&E, SCE, SDG&E

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Part I

1 Staff Proposal on Safety and Operational Performance Metrics

1.1 Introduction

Phase I Track 2 of this proceeding considers safety, operational, and performance metrics and their broad application, including refining the safety performance metrics adopted in D.19-04-020, and developing new metrics as needed. This includes the development of SOMs for PG&E's EOE process, approved in D. 20-05-053.[13]

The November 2, 2020 Scoping Memo outlined the following Phase I Track 2 issues:[14]

- Issue (a): 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 metrics? What is the relationship and/or difference between safety metrics and operational metrics?
- Issue (b.) Should the safety and operational performance metrics apply to all Investor-Owned Utilities (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?
- Issue (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?
- Issue (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?
- Issue (e.) Should the Commission develop a method to streamline safety performance metrics development and reporting across proceedings? If so, what methods should be considered?
- Issue (f.): 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 addressing safety and operational metrics.[15] Should the Commission adopt quality of service and management metrics for PG&E in this proceeding? If so, what are appropriate

[13] Scoping Memo, at 3.

[14] Scoping Memo, at 5.

[15] Decision Approving Reorganization Plan (D.20-05-053), at 105.

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?[16]

The November 17, 2020 ACR directed PG&E to develop SOMs suitable for use as Triggering Events as specified in the EOE process. PG&E proposed 12 SOMs, and electric overhead conductor metrics from its proposed SOMs, as directed in the ACR because these metrics were under development by the S-MAP Technical Working Group, pursuant to D.19-04-020.[17] In subsequent comments and reply comments in this proceeding, parties critiqued PG&E's proposals and offered additional SOMs.

The first R. 20-07-013 Phase I Track 2 Workshop was held on January 28, 2020. It began with PG&E's SOMs presentation, which PG&E submitted to the docket in response to the November 17, 2020 ACR. The rest of the workshop was dedicated to other IOUs' and Intervenors' perspectives on PG&E's proposed SOMs.

After the workshop, Staff held a Phase I Track 2 R.20-07-013 TWG Kick-Off Meeting on April 1, 2021 to discuss the workplan and schedule to address Phase I Track 2 SOMs issues.

Following review of PG&E's proposed SOMs and ensuing party comments, Staff circulated a draft of a proposal on April 22, 2021 (Draft Staff Proposal) addressing Phase I Track 2 issues outlined in the Scoping Memo to the TWG.

On May 4, 2021 Phase I Track 2 TWG Meeting #2 was held to discuss the Draft Staff Proposal on the Phase I Track 2 safety and operational performance metrics issues outlined in the November 02, 2020 Scoping Memo. Staff requested informal comments from TWG members on the Draft Staff Proposal. TWG members submitted informal comments on the proposal on May 11, 2021.

This document reflects Staff's recommendations following consideration of discussion in the TWG and parties' informal comments on the Draft Staff Proposal.

Appendix C provides a summary of Staff's proposed SOMs and Appendix D provides a summary of Staff recommended modification/additions to adopted SPMs, developed pursuant to D.19-04-020.

[16] D.20-05-053, Appendix A, at 2.

[17] Pacific Gas and Electric Company's Response to Assigned Commissioner's Ruling Regarding Development of Safety and Operational Metrics (PG&E's ACR Response), January 15, 2021.

1.2 Staff Recommendations on Phase I Track 2 Issues

1.2.1 Staff's Proposed Approach to SOMs as Triggering Events

The Scoping Memo asks what safety and operational performance metrics should be developed pursuant to D.20-05-053, which addresses PG&E's reorganization plan. The Scoping Memo also asks whether the Commission should consider adopting metrics in this proceeding to measure PG&E quality of service and quality of management or other aspects of D.20-05-053 concerning metrics, such as identifying a metric to assess levels of safety or risk-driven investments.[18]

D. 20-05-053 approving PG&E's bankruptcy plan of reorganization established an EOE process allowing the Commission to take additional steps to ensure PG&E is improving its safety and operational performance if Triggering Events occur.[19] The steps range from Step 1, which contains enhanced reporting and oversight requirements, to Step 6, involving the potential revocation of PG&E's ability to operate as a California electric utility.

As shown in figure 1, SOMs play a role in multiple steps within the EOE process. The Commission may invoke this process if PG&E self-reports or the Commission becomes aware of Triggering Events covered in the process.

D.20-05-053 describes the 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."[20] D.20-05-053 indicated 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..."[21] Based on the broad terms used to describe them, SOMs can overlap with other Triggering Events identified in the EOE process.

[18] Scoping Memo issues (a) and (f), at 5-6.

[19] D.20-05-053, at Appendix A.

[20] D.20-05-053, at 38.

[21] D.20-05-053, at 96.

Figure 1: Steps in EOE Process that Implicate SOMs.[1]

Step 1: "PG&E fails to comply with, or has shown insufficient progress toward, any of the metrics...contained within the approved Safety and Operational Metrics…" the Commission may order PG&E into Step 1 of the EOE process."

Step 2: "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: "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."

Triggering Events in the EOE process include failure to comply or show sufficient progress with any metrics set forth in:

- Wildfire Mitigation Plans,
- Public Safety Power Shutoff (PSPS) protocols,
- Safety Culture Investigation, or
- any Safety and Operational Metrics.

An additional Triggering Event in Step 1 would occur if PG&E demonstrates insufficient progress toward approved safety or risk-driven investments related to the electric and gas business…"[22] 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 good management practices or if PG&E fails to comply with electric reliability performance metrics.[23]

SOMs are an important element of the multi-faceted EOE process. This process allows the Commission to monitor PG&E's safety and operational performance and take additional enforcement steps, ranging from reporting and corrective action requirements to potential revocation of PG&E's ability to operate as a California electric utility.[24]

[22] D.20-05-053, Appendix A, at 2.

[23] D.20-05-053, Appendix A, at 3.

[24] D.20-05-053, Appendix A.

SOMs and the EOE process also overlap with the Commission's recently updated Enforcement Policy,[25] enforcement aspects of the Safety Performance Metrics,[26] compliance with Renewables Portfolio Standards, compliance with California's greenhouse gas (GHG) emissions reduction goals or the Cap-and-Trade program, Occupational Health and Safety rules, and other state laws and regulations.

In addition to the enforcement implications, SOMs are intended to be used by PG&E for purposes of determining executive compensation. D.20-05-053 and the Wildfire Safety Division guidance on executive compensation indicate that a "a significant component of [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." [27]

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. The Commission is free to pursue all Commission's regulatory authority at its disposal including, but not limited to Resolution M-4846, which adopted the Commission Enforcement and Penalty Assessment Policy.[28] As stated in D.20-05-053, 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. A Commission Resolution would place PG&E in the appropriate step based upon the occurrence of a specified triggering event.[29]

[25] Resolution M-4852: Placing Pacific Gas and Electric Company into Step 1 of the "Enhanced Oversight and Enforcement Process," based on 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)).

[26] *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.

[27] D.20-05-053, at 88. Wildfire Safety Division guidance on executive compensation, December 22, 2020.

[28] Resolution M-4846, Enhanced Oversight and Enforcement process Step 1, Triggering Event A(iii).

[29] D.20-05-053, Appendix A.

1.2.2 Selection of PG&E's SOMs

The Scoping Memo asks what criteria should be used to select metrics as SOMs.[30]

Following guidance outlined in the November 2020 ACR, Staff developed its proposed SOMs to meet two primary objectives: (1) 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; and (2) SOMs should be suitable, over time, for the Commission, intervenors, and the public to gauge the safety and operational performance of gas and electric IOUs.[31]

In selecting SOMs, Staff sought metrics that are objective, outcome-based, defined clearly, auditable/verifiable, enforceable, measurable over time, and preferably, leading indicators.

This Staff Proposal also discusses clean energy goals, quality of management, and other possible metrics. Staff has selected SOMs that will serve as supplemental, cross-cutting tools in support of the Commission's existing oversight and enforcement activities.

Staff's proposed SOMs apply exclusively to PG&E. The proposed SOMs encompass worker and contractor safety, electric safety risks, reliability, gas safety risks, and customer satisfaction.

1.2.3 Performance Criteria or Targets and Evaluation of PG&E's SOMs

The Scoping Memo asks how the Commission should use the adopted SOMs, and whether the Commission should adopt performance criteria or targets for SOMs at the same time it adopts the metrics, or at a later time.[32]

Staff does not recommend adopting triggers based on specified thresholds for the purpose of PG&E's EOE process at this time. More data collected over a longer period of time is needed for specific, enforceable targets to be developed. Selecting triggering thresholds that may not be statistically valid could force the Commission to move PG&E into an enforcement step when no discernible corrective action would remedy the situation or, alternatively, preclude the Commission from acting based on performance on a metric when enforcement and corrective action would provide a safety benefit.

After collecting additional data, Staff and parties can explore if adopting triggering thresholds based on clear trends is feasible and practical for the selected SOMs. At that time, the Commission could revisit establishment of automatic triggers based on a larger body of data and evidence. Staff intends to implement an "indicator light" approach to metrics' evaluation, measuring important safety and operational characteristics of PG&E's performance. Recognizing that SOMs will overlap other data streams within the

[30] Scoping Memo, issues (a) and (c), at 5.

[31] ACR at 1-4.

[32] Scoping Memo, issue (b), at 5.

Commission, Staff selected metrics that can serve as an indicator for the most concerning risk events.

For example, wildfire ignitions are clearly important to electrical safety. However, rather than incorporating all ignition data already collected by the Wildfire Safety Division, Staff selected ignition data in High Fire Threat Districts (HFTD) Areas as a SOM.

The EOE process refers to "insufficient progress" and "poor performance" leading to Triggering Events.[33] Staff recommends that the SOMs be used like other Triggering Event metrics in the EOE process - analyzing submitted SOMs for "insufficient progress" based on context, trends, and statistical relationships with other relevant data in those metrics.

Staff is proposing to use qualitative and quantitative evaluations of PG&E's performance as measured by the proposed SOMs. As part of its evaluation, Staff would analyze PG&E's performance with respect to SOMs based on current data and historical trends, to assess anomalies and abnormally large variance in performance trends associated with a single or multiple SOM(s). Staff would also evaluate the SOMs qualitatively using additional contextual information, such as exogenous factors including major events (major storms, heat waves, and earthquakes etc.) that may have led to anomalies and abnormal variations in the reported SOMs. Staff will use this evaluation approach to determine what would constitute "insufficient progress" and/or "poor performance." Based on the findings, Staff will then recommend the Commission invoke the applicable Step in the EOE process, if warranted.

Staff's proposed evaluation approach is consistent with the Commission's intent in evaluating PG&E's performance, as stated in the decision adopting the EOE process:

> "*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.*"[34]

[33] D.20-05-053, Appendix A.

[34] D.20-05-053, at 39.

Data Collection and Reporting Requirements

With regard to PG&E's SOMs, the Commission states that "[w]hile 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."[35]

Staff recommends that PG&E report its SOMs annually. Many of the metrics encompassed in SOMs are also reported to the Commission more frequently, such as on a quarterly basis. To establish baselines, which would enable the assessment of PG&E's future performance relative to historical trends, Staff recommends that PG&E provide all available historical data with its first SOMs submission.

For each SOM, PG&E would include the following:

- All available historical data for the metric.
- A proposed target for the year following the reporting period for each metric as well as a five-year target for each metric. The proposed target may be specific values, ranges of values, rolling average, or other specified target value.
- A narrative description of the rationale for the selection of the targets established for each SOM and why a specific value, a range of values, rolling average or other type of target is selected.
- A narrative description of progress on each metric towards the proposed annual and five-year targets.
- A narrative description on any substantial deviation on the metrics from prior trends based on quantitative and qualitative analysis, as applicable.
- A brief description of current and future activities to meet the proposed targets.

[35] D.20-05-053, at 39.

1.2.4 Application of SOMs to Other IOUs

The Scoping Memo asks if the SOMs should apply to all IOUs[36]. Staff proposed SOMs are intended to apply exclusively for PG&E's EOE process. Staff does not propose any additional application or use of the SOMs for other IOUs.

The EOE process was conceived of in an ACR in Investigation (I.) 19-09-016 related to PG&E's bankruptcy.[37] As indicated earlier, the primary purpose of SOMs is for use as a Triggering Event in the EOE process as articulated in D.20-05-053, applicable only to PG&E; and in part for PG&E's determination of its long-term incentive compensation on safety performance.[38] The Wildfire Safety Division also restates this requirement as applicable to PG&E in their guidance on submittal of executive compensation plans for approval as part of the safety certificate process.[39]

Staff does not see grounds for expanding the application of the EOE process to other utilities at this time. Staff, does, however recommend collection of additional SPMs for all utilities for the purposes of oversight and enforcement in conjunction with other investigations, audits, and inspections outside of the EOE process as envisioned in D.19-04-020.[40] Part II of this Proposal includes a discussion on Staff's recommendations on SPMs.

[36] November 2, 2020 Scoping Memo at 5.

[37] Assigned Commissioner's Ruling and Proposals in Investigation 19-09-016, February 18, 2020, at 10.

[38] D. 20-05-053, at 88.

[39] Wildfire Safety Division guidance on executive compensation, December 22, 2020.

[40] D.19-04-20, at 33.

1.3 Discussion

Conceptualization of SOMs

Some parties either expressed concern or disagreed with Staff's assertion that the absence of a definition of SOMs in D.20-05-053 as well as their broad description, "ensure that PG&E provides safe, reliable and affordable service consistent with California's clean energy goals,"[41] necessarily indicates that SOMs would overlap with other metrics collected by the Commission.

Mussey Grade Road Alliance (MGRA) indicates they are "concerned that there will be significant duplication of metrics between those collected by the Wildfire Safety Division and those required for the EOE process."[42] Staff does not dispute that there will be duplication of data collected by the Wildfire Safety Division. However, as noted above and described in the TWG meeting, Staff deliberately selected a subset of metrics already collected or substantially similar to those collected by the Wildfire Safety Division for several reasons.

The November 2020 ACR requesting that PG&E propose SOMs noted that PG&E "may draw upon existing utility key performance indicators or similar metrics."[43] If PG&E is already collecting and submitting data that informs safety performance to the Commission, Staff does not see a reason to collect new and unique data if the metric under consideration already provides key information regarding PG&E's safety and operational performance. Rather, Staff selected a subset of data that reflect the highest risk indicators with the idea that SPD would provide "belt and suspenders" on other enforcement and oversight activities. This will foster greater collaboration and communication between the new Office of Energy Infrastructure Safety (OEIS) and SPD in overseeing PG&E's activities.

MGRA continues that "[i]t should be noted that the Wildfire Safety Division will be exiting the Commission within the next months and will no longer be a 'Division.' Additionally, the data collected to support the Wildfire Mitigation Plans are not 'Proceedings.' The Draft should be revised to note that Commission staff should attempt to coordinate and align data collection with [Wildfire Safety Division]."[44] Staff is aware that Wildfire Safety Division is leaving the Commission to become OEIS. The Commission and OEIS are finalizing a Memorandum of Understanding (MOU) to facilitate information sharing. This will include an agreement to share electrical infrastructure and wildfire mitigation tabular and spatial data.

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[41] D.20-05-053, at 38.

[42] MGRA's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 1.

[43] PG&E's ACR Response.

[44] MGRA's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 4.

PG&E also takes issue with Staff's interpretation of the description of SOMs as necessitating overlap with other metrics/enforcement coverage stating, "SPD states that the Commission's 'broad description' indicates that the 'SOMs unavoidably overlap with other Triggering Events.' PG&E disagrees. The SOMs represent one part of a larger framework of metrics in the EOE process, which also includes metrics in the Wildfire Mitigation Plan (WMP) including PSPS protocols and the Safety Culture Investigation. While SPD infers that there will be overlap, the Commission has not found that overlap amongst the triggers is necessary."[45]

The metrics cover both safety and operations. They are intended to measure PG&E's performance in providing energy services in a safe, reliable, affordable way consistent with California's clean energy goals. SOMs are intended to be expansive, covering much of PG&E's activities within the Commission's energy related mission and jurisdiction. In fact, PG&E's own proposed metrics overlap with data collected by other divisions within the Commission and implicate other triggers within the EOE Process. Staff does not see an entirely unique set of metrics that would fit the description and guidance associated with SOMs in D.20-05-053 and the ACR.

Targets and Triggers

Parties generally agree with Staff's approach of not setting automatic thresholds or triggers to move PG&E into the EOE Process.

MGRA "supports the general approach taken by Staff in the development of the Draft Proposal. Specifically, MGRA supports Staff's proposal not to require automatic triggers."[46] "[The Utility Reform Network (TURN)] generally supports the Draft Staff Proposal with the clarifications and changes…TURN supports adopting the SOMs in place without first identifying triggering thresholds for the [EOE process]. This allows the Commission, the utilities and stakeholders a process for moving forward while still gathering additional necessary information."[47] TURN goes on to say later in their comments that "Delaying the adoption of triggers allows the Staff to adopt the SOMs without delay and still requires the utility to provide the data that would be required to establish the triggers going forward."[48] The Public Advocates' Office (Cal Advocates) agrees with TURN that following "adoption of the SOMs, the Commission should convene the Technical Working Group to assess selection of SOMs thresholds and SOMs trends to guide the EOE process."[49]

PG&E states that it "agrees with SPD's proposed approach for target-setting for these SOMs, but requests the following clarifications: (1) the 'goals' should be considered

[45] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 6.

[46] MGRA's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 1.

[47] TURN's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 1.

[48] TURN's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021at 4.

[49] Cal Advocates' Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at cell D7.

indicator-levels for SOMs and should consider overall trends and rolling averages; and (2) indicator-levels should be attainable within authorized funding."[50] Staff generally accepts PG&E's position.

This Staff proposal clarifies that the one- and five-year targets (initially referred to as goals), could be specific values, rolling averages, ranges, or other targets. Staff includes an additional reporting requirement for PG&E to provide a rationale for establishing the specific target for each SOM.

Staff agrees with PG&E that the SOMs should be "attainable" as is consistent with the description of SOMs in D.20-05-053.[51] However, PG&E requests that Staff specify "attainable with authorized funding."[52] Staff interprets the phrase "authorized funding," as approved ratepayer funded expenditures and risk mitigation activities funded as part of General Rate Case. While safety-related investments are almost entirely funded using approved expenditures, there are cases arising from civil, criminal, or administrative penalty settlements or by an order stipulating that specified activities be funded with shareholder dollars. If these types of activities are included within "authorized funding," Staff does not see a reason to object to PG&E's proposed caveat.

SOMs as a Flexible Enhanced Enforcement Tool

In their comments PG&E states, "[w]hile SPD acknowledges the 'overlap' between the SOMs, SPMs, and Resolution M-4846 in the Draft Proposal, PG&E requests that…SPD confirm that it will follow the Policy adopted in Resolution M-4846 in any enforcement action."[53]

Staff does not agree that Resolution M-4846 binds the EOE process. Pursuant to D.20-05-053, the EOE process "delineates an entirely new and additional oversight and enforcement process for the Commission, and does not supplant or preclude the Commission from its continuing enforcement role, including the issuance of Orders to Show Cause and opening of investigations through Orders Instituting Investigations."[54] Nothing in Staff's recommendation is intended to affect such jurisdiction or limit the Commission's authority to pursue other enforcement related to subject matter covered or facts implicated by the SOMs. As indicated in Resolution M-4846, the Commission's Enforcement Policy, "the Commission currently uses numerous enforcement tools such as Orders Instituting Investigation (OII), Orders to Show Cause (OSC), citations, subpoenas, stop-work orders,

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[50] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 3 and 4.

[51] D.20-05-052, at 38.

[52] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 1.

[53] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 5.

[54] D.20-05-053, at 55.

revocations of authority, referrals to other agencies, or court actions. These tools remain unaltered by this resolution."[55]

As noted, Staff recommends substantiating a "triggering event" for SOMs in a manner similar to the process undertaken for Resolution M-4852. There, the Commission evaluated the facts and found that PG&E had demonstrated insufficient progress toward approved safety or risk-driven investments related to its electric business.[56] For the purposes of substantiating a triggering event with SOMs, Staff may identify one or more of the SOMs, examine associated facts and recommend that the Commission act to move PG&E into the appropriate EOE process step based on consideration of the facts, as appropriate. Staff may also propose other types of enforcement as appropriate.

PG&E also argues that SOMs should not be used for the purpose of information gathering because it is contrary to the intent of SOMs, and that "SOMs are not a resource to better understand and parse data; they must be used specifically as a potential triggering event to evaluate whether PG&E is providing a reasonable level of service."[57]

As noted above, in selecting each SOM staff's primary criteria was that the metric "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." However, additionally, according to November 2020 ACR, SOMs "should be suitable, over time, for the Commission, intervenors, and the public to potentially gauge the safety and operational performance of all gas and electric IOUs."[58]

Staff believe that each of the SOMs either individually, in combination, or in conjunction with other data used to evaluate the SOMs, are suitable for use as Triggering Events. As discussed above, Staff is recommending an "indicator light" approach and not adopting specific thresholds and/or targets to assess PG&E's performance. Moreover, the information provided by SOMs could be instrumental to eventually modifying or developing new SOMs and developing future performance targets.

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[55] M-4852, at 2.

[56] Resolution WSD-003 (at 24-25) and WSD's June 11, 2020 Action Statement on PG&E Wildfire Mitigation Plan (at 3-5) required PG&E to demonstrate that it was using a system of risk prioritization in all of its wildfire mitigation work. This direction included a requirement that PG&E use risk assessment to determine where to target its Enhanced Vegetation Management (EVM) work. WSD found that less than five percent of the EVM work PG&E completed in 2020 was done to the 20 highest-risk power lines. This failure to appropriately prioritize and execute EVM on its highest-risk power lines was determined to be a Triggering Event under Step 1, Section A(iii), because PG&E demonstrated insufficient progress toward approved safety or risk-driven investments related to its electric business.

[57] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 6.

[58] Assigned Commissioner's Ruling Regarding the Development of Safety and Operational Metrics, November 17, 2020, at 1.

Factors Outside PG&E's Control

PG&E opposes inclusion of SOMs that include factors outside PG&E's control, citing the impact of variations in weather conditions from minimal to extreme.[59] For example, PG&E argues that Staff's proposed SOMs including PSPS, reliability, and Wires-Down metrics that include Major Event Days (MEDs) would be impacted by variations in weather conditions, such that "…a year with above average extreme weather events will likely drive an increase in adverse performance, even if PG&E improved its processes and performed reasonably," which would "…obfuscate the Commission's ability to evaluate whether PG&E is performing reasonably."[60]

Staff disagrees with PG&E's assertion that the inclusion of MEDs in Staff's proposed SOMs "seeks to measure utility failure in conditions beyond utility control and design standards."[61] A metric that measures failure of a utility's asset on MEDs gives visibility to the utility's vulnerability to events such as extreme weather conditions and could reveal underlying factors that might have contributed to the failure. These may include the condition of the utility's assets or the utility's management, maintenance, and operation of that asset.

Extreme weather patterns are one factor that can affect MEDs, but so can other factors, such as:

- Deficiencies in overhead electric system design, operation, and maintenance;
- Deficiencies in workforce planning and training;
- Deficiencies in planning, procurement, and delivery of reliable energy resources, including natural gas supplies to power plants; and
- Failure to adequately harden a utility electric system and plan upgrades for the effects of climate change, including increased frequency of extreme weather events.

A utility is expected to assess, and address risks associated with extreme weather events, climate change impacts, and other exogenous factors that affects the safety and reliability of its system and operations. In fact, a recurring theme in the Risk Assessment and Mitigation Phase (RAMP) and General Rate Case (GRC) proceedings is how a utility should identify and mitigate risks associated with low frequency, but high consequence events, such as safety and reliability risks posed by extreme weather events that could result in catastrophic wildfires.

As a general matter, Staff disagrees that the presence of exogenous factors in a metric makes the metric unsuitable as a SOM. As noted, metrics that include MEDs, which may

[59] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 9.

[60] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 9-10.

[61] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 15.

involve exogenous factors, can provide important information on PG&E's operations and performance, and capture the interactions and impacts that could result from these factors.

As discussed above, Staff is proposing to use qualitative and quantitative evaluations of the proposed SOMs, including underlying data. Staff would conduct rigorous quantitative analysis of PG&E's SOMs data based on current and historical trends, to determine if a "spike" and/or continuous deterioration in trends associated with a single and/or multiple SOM(s) would constitute "insufficient progress" or "poor performance." Based on the findings, Staff will then recommend the Commission invoke the applicable Step in the EOE process, if warranted. This approach provides staff an opportunity to consider to what extent changes in the SOMs are driven by exogenous factors.

Staff recognizes PG&E's concern regarding exogenous factors in SOMs. As indicated in their informal comments, while supporting Staff's inclusion of reliability and PSPS metrics in PG&E's SOMs, MGRA emphasizes the importance that metrics be properly normalized against the magnitude of external driver events.[62] Staff is open to considering approaches to normalize SOMs, to control the impacts of such external driver events and/or MEDs. This could include addressing year over year variation by normalizing against specific types of exogenous events related to environmental conditions, extreme weather conditions (major storms), or earthquakes etc. Normalization could also take the form of the IEEE statistical approach, known as the 2.5 Beta Method. The 2.5 Beta methodology was developed to normalize reliability indices and extract MEDs so they can be studied separately from electrical system performance that occurs during normal conditions. This approach seeks to limit the effect of weather in making year to year comparisons. Normalizing reliability and electric safety related metrics to identify and separate, external driver events or major events that are so far away from normal performance (outliers), would allow for analyzing and trending the data, and setting appropriate targets.

[62] MGRA's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 7.

2 Safety

2.1 Worker Safety Related SOMs

In its Draft Staff Proposal, which was circulated to the TWG for informal comments, Staff initially proposed safety related SOMs, outlined in the following sub-sections.

Staff recommends the following Serious Injury or Fatality (SIF) related SOMs:

- Rate of SIF-Actual Employee
- Rate of SIF-Actual Contractor
- SIF-Potential Rate (Employee)
- SIF-Potential Rate (Contractor)

Refer to Appendix C for a summary of Staff Proposed SOMs, including modified SOMs based on suggestions made by parties in their informal comments on the Draft Staff Proposal.

2.1.1 SIF-Actual (Employee and Contractor)

PG&E proposed *SIF Actual (Employee and Contractor)*, defined as follows:

"Any injury or illness resulting from work at/for PG&E that results in: [63]

- *A fatality – a work-related fatal injury or illness;*
- *A life threating injury or illness – a work-related injury or illness that, if not addressed, could lead to a fatality, or a work-related injury or illness that required immediate life-preserving rescue action, and if not applied immediately, would likely have resulted in the death of that person; or*
- *A life-altering injury or illness – a work-related injury or illness that resulted in a permanent and significant loss of a major body part or organ function. life-threatening or life-altering injury or illness, or fatality, to an Employee or Contractor resulting from work at/for PG&E. Metric is drawn from the Safety Performance Metrics (SPMs). This metric is benchmarkable, outcome-based, and relies on objective data."*

San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas), (Sempra), criticize PG&E's January 15, 2021 proposed SIF Actual metric, indicating that it does not provide a specific process or criteria to evaluate incidents, which could lead to ambiguity and is inadequate for benchmarking.[64] SCE proposes the use of the

[63] PG&E's ACR Response, at 10-11.

[64] Sempra's Comments on Administrative Law Judge's Ruling that Requested Additional Comments on Pacific Gas & Electric Company's Proposed SOMs (Sempra's March 1, 2021 Additional Comments), March 1, 2021, at 2.

use of the Edison Electrical Institute (EEI) 14 criteria method for use in determining whether a workplace injury constituted a reportable SIF.[65] Staff notes the EEI method was developed in conjunction with nationally recognized experts and utilities throughout the United States and has been adopted by several utilities including ConEd, Duke, the Tennessee Valley Authority, Portland General Electric, Southern California Edison Company (SCE), SDG&E, SoCalGas, and several others.

PG&E indicates their definition of SIF Actual is intended to prioritize the most serious of injuries and focus and prioritize corrective actions towards the most serious "life-altering" or "life-threatening" events. To address PG&E's lack of conformity to other utilities' methods of accounting for SIF Actual, Staff's April 22, 2021 Draft Staff Proposal would have required that SIF Actual reporting be consistent with Cal Occupational Safety and Health Administration (OSHA) reporting requirements. In their May 11, 2021 informal comments, PG&E states that they support inclusion of a SIF Actual metric and indicated they could conform their reporting to the same EEI system used by other utilities rather than the Cal OSHA requirements.[66] This proposal would address the concerns raised by SoCal Gas and SCE and provide for a high-quality metric for SIF Actual.

Staff supports aligning the definitions of SIF Actual across all IOUs for the purpose of greater comparability and benchmarking among IOUs. This will also allow the Commission and interested stakeholders to better compare safety performance of IOUs with other industry sectors enabling a greater contextual understanding of the PG&E's SIF numbers.

For Contractor SIF Actuals, Cal Advocates recommends Contractor SIF include an additional requirement that PG&E impose a condition on their contractors to compel them to report SIF Actuals as a condition of doing utility related work for PG&E.[67] Staff concurs with this recommendation to ensure that contractors are appropriately incentivized to report SIFs according to EEI methodologies. In addition to adopting Staff's proposed definition of SIF Actual SOMs, Staff recommends the Commission require PG&E to impose this requirement on their contractors.

[65] SCE's Comments on Administrative Law Judge's Ruling that Requested Additional Comments on Pacific Gas & Electric Company's Proposed SOMs (SCE's March 1, 2021 Additional Comments), March 1, 2021, at 8.

[66] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 17.

[67] Cal Advocates' Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at cell D11.

2.1.2 SIF-Potential (Employee and Contractor)

PG&E's January 15, 2021 SOMs proposal includes SIF-Potential as a SOM. They define SIF-Potential as "[A]n incident that had the credible potential to cause a fatality, life-altering injury or illness or life-threatening injury or illness."[68] PG&E indicates that when this metric is coupled with the SOM for SIF Actual, the paired metrics meet the goals and criteria outlined by the bankruptcy reorganization decision and the ACR requesting SOMs.[69]

In response to a February 1, 2021 Administrative Law Judge's (ALJ's) Ruling, PG&E elaborates on their prior SIF-Potential definition as a "credible potential" for a serious injury as a circumstance that includes: (i) a high energy incident, (ii) where there is no direct control and (iii) a serious injury is not sustained.[70] PG&E's SIF-Potential determination process includes the following four questions:[71]

> *1. Was high energy present? The term 'high energy' refers to a condition where the physical energy exceeds 500 ft-lb.*
>
> *2. Did a high-energy incident occur? A high energy incident is defined as an instance where the high energy source was released and where the worker came in contact with or proximity to the high energy source.*
>
> *3. Was a serious injury sustained? [A serious injury incorporates PG&E's proposed SIF Actual definition including determination as to whether or not "injury was or could be "life threatening" or "life altering."]*
>
> *4. Was a direct control present? A direct control is present if (i) the control is specifically targeted to the high energy source; (ii) the control effectively mitigates exposure to the high energy source when installed, verified, and used properly (i.e., a SIF should not occur if these are present); and (iii) the control is effective even if there is unintentional human error during the work (unrelated to the installation of the control).*

Staff notes that this approach is generally consistent with current understanding that a reduction in all accidents, including those that result in less severe injuries, does not correspond to a reduction in SIFs and that it is necessary to focus on specific precursors of SIFs rather than merely accident avoidance.[72]

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[68] PG&E's ACR Response, at 11.

[69] PG&E's ACR Response, at 11.

[70] Response of Pacific Gas and Electric Company to the Administrative Law Judge's Ruling Regarding SIF Potential, February 12, 2021, at 2.

[71] Response of Pacific Gas and Electric Company to the Administrative Law Judge's Ruling Regarding SIF Potential, February 12, 2021, at 3.

[72] Terry McSween & Daniel J. Moran Assessing and Preventing Serious Incidents with Behavioral Science: Enhancing Heinrich's Triangle for the 21st Century, 2017 Journal of Organizational Behavior Management, at 37:3-4, 283-300

In their March 1, 2021 informal comments, TURN states that "increases in SIF Potential events would demonstrate more near misses, which is concerning, but also indicate the avoidance of more serious events, which would be welcome."[73] TURN indicates that "the SIF- Potential metric neither provides helpful information on PG&E's safety conduct nor does it meet the requirements of Commission Guidance."[74] Staff points out that a reduction in SIF potential incidents would reflect a reduction in life-threatening incidents as a result of mitigating risks to workers and contractors. A substantial body of worker safety research over the last several years indicates that the relative infrequency of fatalities and other serious events can give an appearance of them being random and unpredictable. Studying SIF Potential events – the occurrence of an injury, accident, near miss, or exposure that is likely to result in serious injury or death if repeated, enables organizations to understand the systems or environments that are more likely to lead to SIFs.[75]

In their March 1, 2021 information comments, Sempra correctly point out that PG&E's process for identifying SIF Potential includes a "detailed, multi-step decision tree on how PG&E derives the determination of whether an incident had 'SIF-Potential.' In order for this metric to be comparable across IOUs, as is the Commission's stated objective with the Safety Performance Metrics, each IOU would need to adopt this exact same decision tree and apply each step in the exact same way. PG&E's proposed SIF-Potential metric is thus too subjective to use as a basis for comparison."[76]

In their March 1, 2021 informal comments, Sempra also argue that "near miss reporting… is seen as a positive move forward in enhancing a company's safety culture and should not be viewed by the Commission or others as a rate that should be managed. The internal follow-up, lessons learned, and corrective actions are the important factors, not the number of potential incidents that have been identified."[77] SCE, on the other hand, states "that the SPM [report] criteria could be modified to adopt the Edison Electric Institute (EEI) Safety Classification and Learning Model (SCL) Employee and Contractor SIF definitions for actual *and potential* SIF. This will allow a greater degree of benchmarking with utilities outside of California. It will also leverage the work of EEI's working group(s) of industry safety leaders and technical advisors and experts."[78] Staff agrees that capturing SIF potentials would be beneficial and could produce more effective strategies to reduce SIF Actuals.

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[73] TURN Comments on Administrative Law Judge's Ruling that Requested Additional Comments on Pacific Gas & Electric Company's Proposed SOMs (TURN March 1, 2021 Additional Comments), at 6.

[74] TURN March 1, 2021 Additional Comments at 6.

[75] See for example, Martin, D. K., & Black, A. (2015, September). Preventing serious injuries & fatalities—Study reveals precursors & paradigms. Professional Safety Journal, at 35–42.

[76] Sempra's March 1, 2021 Additional Comments, March 1, 2021, at 3.

[77] Sempra's March 1, 2021 Additional Comments, March 1, 2021, at 3.

[78] SCE's March 1, 2021 Additional Comments, March 1, 2021, at 8.

Given that PG&E's total number of SIFs increased from 2019 to 2020, Staff is interested in ways the company can reduce this number and is receptive to this metric as a SOM.[79] PG&E's proposed SIF Potential metric was developed in consultation with Edison Electric Institute,[80] and is consistent with methodologies found to be effective by DEKRA based on seven multinational organizations and over 1,000 SIF incidents.[81] Both the Edison Electric Institute working group and the DEKRA study found that SIF exposure decisions trees, with appropriate training, can be highly accurate in identifying incidents that could have resulted in SIFs, but did not. As SCE noted, a Safety Classification and Learning (SCL) approach to SIF Potential allows them to "learn from potential incidents, not just those that result in serious injuries, and to communicate these learnings to the Commission."[82] Staff sees a benefit to this approach for both PG&E's employees and contractors as well as all other utilities' employees and contractors.

In the April 22, 2021 Draft Staff Proposal, Staff recommended the *Potential SIF Rate* be reported as a SOM for both employees and contractors for purposes of the EOE process. The metrics would be:

- *Potential SIF Rate (Employee)*
- *Potential SIF Rate (Contractor)*

SIF-Potential would be defined as:

> *Potential SIF incidents identified by using the Edison Electric Institute Safety Classification and Learning (SCL) Model, where a SIF incident in this case would be events that could have led to a reportable SIF.*[83]

Potential SIF Rate would be calculated using the formula:

> *(Number of SIF-Potential (incidents) x 200,000)/hours worked for (Employee or Contractor)*

Use of the Edison Electric Institute methodology has at least two benefits. First, it is based on actual case studies and the data-driven acknowledgement across multiple industry sectors that a reduction in all types of accidents has not resulted in a corresponding reduction in serious injuries and fatalities.[84] On the contrary while minor injuries and days away from

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[79] Pacific Gas and Electric Company Safety Culture and Governance Quarterly Report No. 09-202 in Compliance with Decision 18-11-050, January 29, 2021.

[80] Safety Classification and Learning Model.

[81] Preventing Serious Injuries and Fatalities (SIFs): A New Study Reveals Precursors and Paradigms. White Paper.

[82], SCE's March 1, 2021 Additional Comments, at 8.

[83] Edison Electric Institute Safety Classification and Learning Model, Dr. Matthew Hallowell

[84] The efficacy of industrial safety science constructs for addressing serious injuries & fatalities (SIFs), Cooper, M.D, Saf. Sci. 2019, at 120, 164–178.

work have been reducing over time, serious injuries and fatalities have increased.[85] Second, it was developed and is being implemented by over 20 utilities throughout the country allowing for comparison of SIF-Potential with PG&E and other utilities in California and in other states.

Following issuance of the Draft Staff Proposal, and a TWG meeting held on May 4, 2021, in its informal comments, TURN proposes that "changes to the requirements should be made to ensure that the most valuable points of information on a SIF event are captured."[86] TURN also indicates they are "concerned that reporting a rate for this metric, could lead to underreporting even if there is no trigger associated with the metric. The utility should be encouraged to capture these events and learn from them, and creating an associated metric, and the related incentives for a declining rate, may discourage reporting."[87] Cal Advocates raises similar concerns stating, "SIF Potential reporting is a useful safety improvement tool. As a SOM, however, SIF Potentials incentivizes underreporting. Cal Advocates is unaware of any regulator using SIF potential as a negative safety performance indicator."[88]

In addition to the concern about under reporting, TURN's informal comments also indicate they are interested in more qualitative information stating, "the rate is not the important data point to take away from a SIF-Potential or a near miss. The important information from a SIF Potential incident is the lesson learned from the event, be it what worked and prevented a SIF Actual or what additional safety measures that would prevent future close calls…Staff should require the utility to provide information on the program area where the SIF Potential occurred, and the lesson learned from the event rather than a rate of SIF potential events."[89] Staff agrees with TURN's suggestion about including qualitative information and shares TURN and Cal Advocates' concern about the potential for under reporting. Staff believes the underreporting issue is mitigated by the lack of a specified target. Staff plans to evaluate the submitted SOMs for anomalies from trends in prior reporting years.

For SIF Potential, either a large increase or a large decrease could be a matter of concern that would need to be further investigated. For example, if there was a 25 percent drop in SIF Potential incidents without a corresponding drop in the amount of hazardous work being conducted this would be concerning and merit investigation into reporting

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[85] The efficacy of industrial safety science constructs for addressing serious injuries & fatalities (SIFs), Cooper, M.D, Saf. Sci. 2019, at 120, 164–178.

[86] TURN's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 3.

[87] TURN's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021.

[88] Cal Advocates Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at Cell 14.

[89] TURN's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 3.

practices. Likewise, if there was a 25 percent increase in SIF Potential Incidents, Staff would investigate for patterns and causation.

Additionally, for reporting SIF Potential under PG&E's reporting policies, front line employees and contractors do not decide which events are considered SIF Potential or SIF Actuals. They report safety incidents and PG&E retains a third-party contractor to determine within a two-day period if an injury or near hit should be considered a SIF Actual or SIF Potential. As part of their efforts to improve safety and continue to implement the recommendations for their Safety Culture Investigation, PG&E asserts that it continues to foster an environment where "learn and improve" is valued over "blame and shame."[90] PG&E indicates they continue to train and communicate to workers the importance of reporting incidents by employees and contractors as a means of protecting their own safety as well as that of their colleagues. While all reporting systems and workplace cultures can be improved, PG&E, like other utilities, has noted that it continues to encourage robust and comprehensive incident reporting.[91]

The Commission will continue to monitor PG&E's reporting culture via annual and quinquennial safety culture assessments as required by Public Utilities Code sections 8389(d)(4) and 8386.2, respectively.

Staff agrees with TURN's comment described above that, in addition to submitting SIF Potential Rate, PG&E should be required to include a qualitative description of each reported SIF Potential event. Any Triggering Event would be largely based on trends in a metric or metrics, but additional qualitative information could inform interpretation of the data.

In supporting inclusion of the SIF Potential Metric, PG&E indicates that they have adopted the modified Edison Electric Institute SCL model. While their initial recommendation proposed adoption of their modified version, PG&E comments that it can easily adapt their method to the Edison Electric Institute SCL model used by other utilities.[92]

After consideration of the discussion on May 4, 2021 and the informal comments received on May 11, 2021, Staff retains the initial recommendation included in the Draft Staff Proposal, but recommends adding supplemental reporting requirements, requiring

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[90] The recommendations included in the Assessment of Pacific Gas and Electric Corporation and Pacific Gas and Electric Company's Safety Culture: Final Report (provided to the Commission on May 8, 2017) were required to be implemented by Decision D.18011-050 part of I.15-08-019. The latest update from PG&E implementing the recommendations are found in Safety Culture and Governance Quarterly Report No. 10-2021 in Compliance with CPUC Decision 18-11-050, April 30, 2021.

[91] The recommendations included in the Assessment of Pacific Gas and Electric Corporation and Pacific Gas and Electric Company's Safety Culture: Final Report (provided to the Commission on May 8, 2017) were required to be implemented by Decision D.18011-050 part of I.15-08-019. The latest update from PG&E implementing the recommendations are found in Safety Culture and Governance Quarterly Report No. 10-2021 in Compliance with CPUC Decision 18-11-050, April 30, 2021.

[92] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 18.

PG&E to provide information on the program area where the SIF Potential occurred, and the lesson learned from the event, as suggested by TURN.[93]

Staff's final recommendations on SIFs related SOMs are provided in Appendix C, including the additional reporting requirements.

2.2 Staff Recommendations on Worker Safety and Operational Metrics

Based on parties' Informal Comments on the Draft Staff Proposal and discussions in the TWG, Staff propose the following Safety and Operational Metrics:

1. *Employee SIF Actual Rate = (Number of SIF-Actual cases among employees x 200,000)/employee hours worked*[94]
2. *Contractor SIF Actual Rate = (Number of SIF-Actual cases among contractors x 200,000)/employee hours worked.*
3. *Rate of SIF Potential (Employee) = (Employee SIF Potential Cases x 200,000)/total employee hours worked.*[95]
4. *Rate of SIF Potential (Contractor) = (Contractor SIF Potential Incidents x 200,000)/total contractor hours* worked.

Collecting data on the rates would allow for comparison across utilities despite differing number of employees and contractors.

Staff additionally recommends that the Commission require PG&E to establish reporting requirements for its contractors to report SIF Actuals to PG&E, as recommended by Cal Advocates in their informal comments on the Draft Staff Proposal. In addition, consistent with TURN's recommendations, Staff recommends that PG&E includes, with the SIF Potential data submittals, an attendant qualitative description of the SIF Potential incidents, as well as lessons learned and any proposed corrective actions.

For consistency, Staff also recommends the Commission similarly modify the definition of the *Serious Injuries and Fatalities (Employee and Contractor)* SPM adopted in D.19-04-020.[96] Refer to Part II of this document for discussion on SPMs.

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[93] TURN's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 3.

[94] A SIF Actual case is determined using the methodology approved by the Edison Electrical Institute's Occupational Health and Safety Committee.

[95] SIF Potential Incidents would be determined using SIF Potential incidents would follow the Potential Serious Injury or Fatality (P-SIF) from the Edison Electrical Institute's Safety Classification and Learning Model.

[96] D.19-04-020, Attachment 1, at 5-6. *OSHA Recordables Rate (Employee and Contractor)* adopted in D.19-04-020: SPM number 17. *Employee OSHA Recordables Rate*, and SPM number 18. *Contractor OSHA Recordables Rate*, to include "serious injury" definition as adopted in the January 1, 2020 CAL OSHA.

2.3 Potential High Threat Public SIF

PG&E proposes the development of a Public Safety metric that: (1) suits the purpose of enhanced operational enforcement and (2) is scoped appropriately to omit incidents outside of PG&E's control; PG&E proposed a definition for Public Safety metric as follows:[97]

> *"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."*

SCE states that the current Public SIF metric definition meets the purposes of the Safety Performance Metrics Report and would not recommend making an update at this time.[98]

TURN states that while PG&E should be working to avoid any public safety incidents, the SOMs should accurately reflect safety performance including the relative impact of each safety incident, "First, the metric should count impacts, in terms of SIF, rather than incidents."[99] TURN indicates that there should be two measures of impacts – one that captures the impact from all incidents and another that only shows impacts from incidents "resulting from work on or caused by a failure or malfunction of PG&E facilities.[100]

Staff agrees that SOMs should include a metric that captures risks to public safety including events that could result in injuries and fatalities. However, a standalone Public SIF Potential SOM is not necessary to accomplish the goal of effective oversight and enforcement. There are already severe criminal and civil penalties associated with causing the death or injury to a member of the public. Whether an incident is caused by a systematic failure of PG&E's infrastructure and/or operation, or by a random event outside the control of PG&E, the incident will be subject to an investigation, and possible civil and criminal penalties from the Commission and/or through courts.

If any IOU is found to be responsible or is likely to be responsible for serious injuries or deaths, then it would not be appropriate for the Commission and other relevant authorities to wait on the submittal of a SOMs report and respond to data when made available. Instead, immediate action should be taken. The full force of law enforcement and the Commission's substantial enforcement powers should be brought to bear. Rather than proposing corrective actions to get out of one of the steps in the EOE process, corrective actions and penalties should be dealt with in appropriate Commission, criminal and civil proceedings with severe legal and financial consequences. Therefore, Staff does not recommend the inclusion of a Public SIF Actual as a SOM for the purpose of PG&E's EOE process.

Likewise, Staff does not recommend the creation of a Public SIF Potential SOM. Several SOMs, such as ignitions or wires down during red flag warning days, overpressure events, slow gas shutoff times are, in fact, "Public SIF Potential" incidents that are captured

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[97] Pacific Gas and Electric Company's (U 39M) Post-Workshop Comments on Safety and Operational Metrics, March 1, 2021, at 14.
[98] March 1, 2021 SCE's Comments on PG&E's Proposed SOMs, at 9.
[99] TURN March 1, 2021 Additional Comments, at 8-9.

[100] TURN March 1, 2021 Additional Comments, at 8-9.

by the proposed SOMs. Indeed, the purpose of most of the SOMs are to reduce the potential for injuries and fatalities attributable to IOU infrastructure. Any one or a combination of impacts and incidents have the potential to result in serious injuries and fatalities. In reviewing these SOMs and determining whether "sufficient progress" has been shown, Staff will consider if reportable metrics reflect an increase or decrease in the potential to kill or seriously injure members of the public. As such, Staff recognizes poor performance on these metrics could have grave consequences just as a SIF Potential does in a workplace environment.

In the May 11th comments in continuing to argue for the inclusion of a "Public Safety Metric," TURN argues, "[if] the intent of the EOE is to promote a safer PG&E, it is missing a key safety indicator, Public Safety incidents."[101] TURN continues, "a key aspect of demonstrating a safer utility is a reduction in SIF-Public and they should be included in the required SOMs. As with other SOMs, the availability of alternative remedies should not preclude the utility from also reporting this metric. Put simply, including a Public Safety measure demonstrates to the public that the Commission is prioritizing improved public safety performance in its vision for "safe, reliable and affordable service consistent with California's clean energy goals."

Staff continues to agree with TURN that public safety related metrics demonstrate the Commission is prioritizing public safety performance. However, neither in the April 22nd Draft Staff Proposal on Phase 1, Track 2, nor here does Staff recommend the creation of a SOM for Public SIFs or for Public SIF potential.[102] Staff points out that the various proposed metrics on gas and electrical safety already amount to Public SIF potential metrics in that ignitions, wires down, gas overpressure events, etc. have the potential to result in serious injuries and fatalities. The EOE process' Triggering Events do not match the urgency and gravity of Public SIF Actuals as an enforcement tool. In the event authorities believe that a utility may be or is responsible for a serious injury or fatality, it would be unreasonable for the Commission to wait for an annual report before taking enforcement action including investigations, information sharing with local and state officials investigating the incident, and penalties as appropriate under the circumstances.

A spike in Public SIFs such as those that occurred in San Bruno and the Camp Fire, result in severe criminal and civil penalties, bankruptcy, reorganization, independent monitoring, years-long scrutiny, and extensive corrective actions. SOMs, on the other hand are used for moving PG&E into Steps one, two, and/or three of a six step process with associated corrective actions. This is not proportional to the offense of causing serious injuries or fatalities amongst members of the public and Staff does not agree that Public SIF related metrics would enhance enforcement or oversight in such instances.

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[101] TURN's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 1.

[102] Appendix A, at 32.

Cal Advocates, in their Informal Comments, propose the creation of SOM entitled "Rate of SIF Actual (Public)." They argue "the SIF performance metrics should NOT exclude public safety. Public Safety metrics should instead be used to prioritize corrective actions and for enhanced oversight. Employee/Contractor Safety Performance is an inadequate indicator for Public Safety Performance."

As noted above, Staff believe that the proposed SOMs do not exclude public safety. On the contrary Staff selected safety metrics that they believe indicated the highest risks to public safety. Staff also does not disagree that "Employee/Contractor Safety Performance is an inadequate indicator of Public Safety Performance." The SIF metrics proposed above measure worker safety. While improved worker safety could be indicative of a safety culture that prioritizes safety, possibly including public safety, measuring public safety is not the goal for collecting those metrics.

However, Staff would certainly welcome further discussion with Cal Advocates and members of the TWG on possible methodologies for calculating Rate of SIF Actual (Public). A rate would be a more valuable metric than a raw number and could enable comparison across utilities to assess relative safety performance with respect to the gravest of possible consequences.

At this time, Staff retains the initial recommendation made in its Draft Staff Proposal to exclude Public SIF SOMs to use as a triggering event in the EOE Process.

3 System Reliability: SAIDI, SAIFI & CAIDI

The Commission requires that SOMs track "quality of service and quality of management" issues.[103] Reliability risks go to the very heart of these service and management priorities.[104] 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."[105] 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).[106] Providing reliable service is a fundamental responsibility of an IOU. As such, EOE process on reliability metrics for PG&E are appropriate for inclusion.

In its Draft Staff Proposal, which was circulated to the TWG for informal comments, Staff initially proposed SAIDI, SAIFI and CAIDI Related SOMs, as outlined in the following sub-sections. The Draft Staff Proposal initially included the following SOMs related to reliability for use as Triggering Events for the purpose of PG&E's EOE Process:

- *System Average Interruption Duration (SAIDI) (Unplanned)*[107]
- *SAIDI (All Outages)*[108]
- *System Average Interruption Frequency (SAIFI) (Unplanned)*[109]
- *SAIFI (All Outages)*[110]
- *Customer Average Interruption Duration Index (CAIDI) (Unplanned)*[111]
- *CAIDI (All Outages)*
- *System Average Customers Impacted (All Outages)*

[103] D.20-05-053, at 96; and Scoping Memo 5.

[104] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 12.

[105] American Customer Satisfaction Index Energy Utilities Report 2020-2021, at 6.

[106] 2019 Annual Electric Reliability Report.

[107] An "interruption" is the total loss of electric power on one or more normally energized conductors to one or more customers connected to the distribution portion of the system. In essence, an interruption refers to the customer, as opposed to an outage, which refers to the equipment. PG&E's ACR Response, at 15.

[108] An "outage" is the loss of ability of a component to deliver power.

[109] The Protect our Communities Foundation Comments on Workshop on Safety and Operational Metrics Proposed by Pacific Gas and Electric Company (PCF Comments on PG&E Workshop), March 1, 2021, at 4-5.

[110] PCF Comments on PG&E Workshop, March 1, 2021, at 4-5.

[111] A "customer" is a metered electrical service point for which an active bill account is established at a specific location.

Staff considered parties' suggestions and decided to retain its initial proposed SOMs, as discussed in the following sub sections.

3.1 SAIDI Related SOMs

SAIDI is a reliability metric that measures the average length of time of power outages that customers experience in a period of time[112] In accordance with the definition specified by the IEEE 1366: "A sustained interruption is any interruption that lasts for more than five minutes."[113] Staff recommends including two variations of the SAIDI metric for reporting on SOMs: SAIDI (Unplanned), i.e., SAIDI due to unplanned outages, and SAIDI (All Outages), i.e., SAIDI due to all outages.

3.1.1 SAIDI (Unplanned)

PG&E proposes the SAIDI (Unplanned) metric as a reliability metric relevant to the risk of a failure of electric distribution overhead assets, as well as a quality of service and management measure. PG&E defines this metric as: "The number of minutes associated with unplanned sustained outages that the average customer experiences in a year. It measures all T&D outages and excludes Major Event Days."[114]

The SAIDI (Unplanned) metric is currently reported to the Commission's Energy Division as part of the CPUC Annual Electric System Reliability Report, and to the Wildfire Safety Division as part of WMP.[115] The SAIDI (Unplanned) metric that PG&E currently submits to the Commission reflects the reliability of the grid during routine circumstances, as the metric only captures sustained interruptions and excludes outages on MEDs.

Staff recommends adopting PG&E's proposed SAIDI (Unplanned) as a SOM, expressed in hours per customer rather than minutes per customer to align with WMP, on all transmission and distributions outages, and recommends the following definition:

SAIDI (Unplanned) = average duration of sustained interruptions per metered customer due to all unplanned outages, excluding on Major Event Days, in a calendar year where, *average duration* is defined as:

*Sum of (duration of interruption * number of customer interruptions) / Total number of customers served*

and *duration* is defined as *Customer hours of outages*.

[112] D.96-09-045, Appendix A, at 1.

[113] D.16-01-008, Appendix B.

[114] PG&E's ACR Response, at 15.

[115] D.16-01-008, Appendix B. See CPUC Annual Electric System Reliability Report.

3.1.2 SAIDI (All Outages)

Staff recommends SAIDI (All Outages), as a modified version of the SAIDI (Unplanned) metric, to provide an additional perspective on all outage durations that better reflects customer experience and unpredictable events. The SAIDI (Unplanned) metric that PG&E currently submits to the Commission on an annual basis reflects the reliability of the grid during routine circumstances, but it does not include an aggregate metric representing all of the following sustained outages: planned outages, outages due to PSPS, and outages on MEDs. The inclusion of these additional outages in a SAIDI (All Outages) metric would provide a comprehensive picture of reliability performance under any outage circumstance, ranging from routine to extreme.

While the standard SAIDI (Unplanned) metric reflects the reliability of the grid during routine circumstances, the SAIDI (All Outages) metric provides a different perspective on reliability that could indicate average outage durations that weigh heavily towards extreme circumstances. This modified metric is outcome-based and relies on objective data. At the Commission's discretion, the SAIDI (All Outages) metric may not apply to major events beyond the control of the utility, such as, but not limited to, terrorist attacks or other large-scale unanticipated disasters.

Staff recommends adopting SAIDI (All Outages) as a SOM, expressed in hours per customer rather than minutes per customer to align with WMP, on all transmission and distributions outages. This metric captures the full impacts of all outages on customers. Staff will consider exogenous factors beyond the utility's control when making any recommendation associated with the steps in the EOE process on all Outages data. Staff recommends the following definition:

SAIDI (All Outages) = average duration of all sustained interruptions per metered customer due to all outages, including, but not limited to, unplanned outages, planned outages, PSPS outages, and outages on Major Event Days, in a calendar year

where, *average duration* is defined as:

*Sum of (duration of interruption * number of customer interruptions) / Total number of customers served*

and, *duration* is defined as: *Customer hours of outages*.

3.2 Staff Proposed SAIFI Related Metrics

SAIFI is a reliability metric that characterizes the average number of sustained power interruptions for each customer in a calendar year, [116] in accordance with the definition specified by the IEEE 1366.[117] Staff recommends the inclusion of two variations of the SAIFI metric for reporting on SOMs: SAIFI (Unplanned), i.e., SAIFI due to unplanned outages, and SAIFI (All Outages), i.e., SAIFI due to all outages.

3.2.1 SAIFI (Unplanned)

Protect our Communities Foundation (PCF) proposes the SAIFI (Unplanned) metric, which measures the frequency of outages associated with unplanned sustained outages that the average customer experiences in a year. SAIFI measures sustained interruptions and excludes planned outages and outages due to Major Event Days (MEDs).[118] This metric is already reported in the CPUC Annual Electric System Reliability Report.[119] The SAIFI (Unplanned) metric that PG&E currently submits to the Commission on an annual basis reflects the reliability of the grid during routine circumstances, as the metric only captures sustained interruptions and excludes outages on MEDs.

Staff recommends adopting SAIFI (Unplanned) as a SOM on all transmission and distributions outages and recommends the following definition:

SAIFI (Unplanned) = average frequency of sustained interruptions due to all unplanned outages per metered customer, except on Major Event Days, in a calendar year.

where the *average frequency* is defined as:

Total number of sustained customer interruptions / Total number of customers served.

3.2.2 SAIFI (All Outages)

SAIFI (All Outages) is a reliability metric that modifies the standard version of SAIFI (Unplanned) to include the average frequency of all sustained interruptions, per customer, due to outages from, but not limited to, unplanned outages, planned outages, outages due to PSPS, and outages due to MEDs. This modified version of SAIFI (Unplanned), referred to as SAIFI (All Outages), provides additional perspective on all outage frequencies.

The inclusion of these additional outages in the SAIDI (All Outages) metric would provide a comprehensive picture of reliability performance under any outage circumstance, ranging from routine to extreme. Staff recommends adopting SAIFI (All Outages) as a SOM

[116] D.96-09-045, Appendix A, at 1.

[117] D.16-01-008, Appendix B.

[118] 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).

[119] D.16-01-008, Appendix B.

on all transmission and distributions outages that include all types of interruptions and outages. Staff recommends the following definition:

SAIFI (All Outages) = average frequency of sustained interruptions per metered customer due to all outages, including, but not limited to, unplanned outages, planned outages, PSPS outages, and outages on Major Event Days, in a calendar year.

where the *average frequency* is defined as:

Total number of sustained customer interruptions / Total number of customers served.

3.3 CAIDI Related SOMs

In accordance with the definition specified by the IEEE 1366, CAIDI is a reliability metric that represents the average time required to restore service to affected customers.[120] Staff recommends the inclusion of two variations of the CAIDI metric for reporting on SOMs: CAIDI (Unplanned), i.e., CAIDI due to unplanned outages, and CAIDI (All Outages), i.e., CAIDI due to all outages.

If a single customer experiences more than one sustained interruption during a Measured Event, each interruption shall count as a separate customer interruption. CAIDI shall be measured from the beginning of the Measured Event and shall continue until all customers experiencing interruptions during the Measured Event have been restored.[121]

3.3.1 CAIDI (Unplanned)

Staff recommends adopting CAIDI (Unplanned) as a SOM for use as a PG&E EOE process Triggering Event to review the average time required to restore service to affected customers experiencing sustained interruptions due to unplanned outages. This metric specifically measures the average customer minutes interrupted per impacted customer only, whereas the SAIDI metrics consider the average customer minutes interrupted across all customers.

This metric is already reported in the CPUC Annual Electric System Reliability Report.[122] The CAIDI (Unplanned) metric that PG&E currently submits to the Commission on an annual basis reflects the reliability of the grid during routine circumstances, as the metric only captures sustained interruptions and excludes outages on MEDs.

CAIDI (Unplanned) is defined as the total customer interruption duration due to unplanned outages and excluding MEDs divided by the total number of customers interrupted due to unplanned outages and excluding MEDs, expressed in hours per customer

[120] D.16-01-008, Appendix B.

[121] D.16-01-008, Appendix B. See Institute of Electrical and Electronic Engineers (IEEE) 1366, at 4.

[122] D.16-01-008, Appendix B.

rather than minutes per customer, on all transmission and distributions outages. Staff recommends the following definition:

> *CAIDI (Unplanned) = average duration of sustained outages per* ***impacted*** *metered customer due to all unplanned outages, excluding on Major Event Days, in a calendar year*
>
> where, *average duration* is defined as:
>
> *Sum of (duration of interruption * number of customer interruptions) / Total number of impacted customers*
>
> and *duration* is defined as: *Customer hours of outages*.

In other words, this metric can be calculated as:

SAIDI (Unplanned) / SAIFI (Unplanned).

3.3.2 CAIDI (All Outages)

In contrast to the CAIDI (Unplanned) metric, CAIDI (All Outages) is a reliability metric that includes the average frequency of sustained interruptions, per affected customer, due to outages from, but not limited to, unplanned outages, planned outages, outages due to PSPS, and outages due to MEDs. CAIDI (All Outages) provides additional perspective on the duration of sustained interruptions for impacted customers. The inclusion of these additional outages in the CAIDI (All Outages) metric would provide a comprehensive picture of reliability performance under any outage circumstance, ranging from routine to extreme. Therefore, Staff recommends adopting CAIDI (All Outages) as a SOM for use as a PG&E EOE Process Triggering Event.

CAIDI (All Outages) is defined as the total customer interruption duration due to all outages divided by the total number of affected customers interrupted due to all outages, expressed in hours per customer rather than minutes per customer, on all transmission and distributions outages. In other words, CAIDI (All Outages) represents the average time required to restore service to affected customers. Staff recommends the following definition:

> *CAIDI (All Outages) = average duration of sustained outages per impacted metered customer due to all outages, including, but not limited to, unplanned outages, planned outages, outages due to PSPS, and outages due to Major Event Days, in a calendar year.*
>
> where, *average duration* is defined as:
>
> *Sum of (duration of interruption * number of customer interruptions) / Total number of impacted customers*
>
> and *duration* is defined as: *Customer hours of outages*.

In other words, this metric can be calculated as:

SAIDI (All Outages) / SAIFI (All Outages).

3.4 System Average Customers Impacted (All Outages) SOMs

Staff recommends adopting *System Average Customers Impacted (All Outages)* as a SOM on all transmission and distribution outages for use as a Triggering Event for the purpose of PG&E's EOE process. Staff recommends the following definition:

> *System Average Customers Impacted (All Outages) = average number of all metered customers experiencing sustained interruptions due to all outages, including, but not limited to, unplanned outages, planned outages, outages due to PSPS, and outages due to Major Event Days, in a calendar year.*

where the term *average customers* is defined as:

> *Number of customers impacted / total number of customers served.*

3.5 Reporting Requirements

Currently, the IOUs are required to report the preceding calendar year's electric reliability data, which include SAIDI (Unplanned), SAIFI (Unplanned), and CAIDI (Unplanned) metrics, on July 15th of each year as part of their annual reliability report, pursuant to Decision 16-01-008.[123] The metrics are reported in the Annual Electric Reliability Report to the Energy Division. The most recent reliability metrics available should be reported to SPD with the annual SOMs as well.

3.6 Discussion

Unplanned Outages

In their informal comments on Draft Staff Proposal, both Cal Advocates and PCF agreed that the "unplanned" reliability metrics proposed in the initial Draft Staff Proposal should be included as SOMs. Cal Advocates stated that "reliability related metrics should include both metrics that include Major Event Days and also metrics that exclude Major Event Days."[124] PCF stated that it "appreciated that the Staff Proposal Incorporates SAIFI as a Safety and Operational Metric (SOM) in addition to System Average Interruption Duration (SAIDI)."[125]

PG&E also agreed that the "unplanned" reliability metrics – SAIDI (Unplanned), SAIFI (Unplanned) and CAIDI (Unplanned) – are appropriate SOMs. Yet, even as PG&E agrees with the proposed set of "unplanned" reliability metrics, it notes that "these metrics are all

[123] D.16-01-008, Appendix B.

[124] Cal Advocates TWG Track 2 informal comments on Draft Staff Proposal, May 11, 2021, at Attachment.

[125] PCF'S TWG Track 2 informal comments on Draft Staff Proposal, May 11, 2021 at 7.

similarly situated" and "[the] inclusion of all three metrics does not provide additional information to the Commission, since they all rely on the same sets of data."[126]

Staff disagrees with PG&E's assertion that the three metrics do not provide additional information to the Commission. SAIDI (Unplanned) allows the Commission to track PG&E's performance on the duration of interruptions in a calendar year, while SAIFI (Unplanned) allows the Commission to track PG&E's performance on the frequency of interruptions, both of which are important to track. Even if the three 'unplanned' reliability metrics are "similarly situated," according to PG&E, there is no guarantee the metrics will move in tandem. In other words, the duration of interruptions to the average customer can improve over time even as the frequency of interruptions per customer gets worse. Additionally, the Commission can use CAIDI (Unplanned) to track PG&E performance on duration of customer interruptions per affected customer.

Based on informal written feedback from Cal Advocates, PG&E, and PCF showing consensus on the "unplanned" reliability metrics, Staff continues to recommend SAIDI (Unplanned), SAIFI (Unplanned), and CAIDI (Unplanned) as SOMs.

SAIDI (All Outages), SAIFI (All Outages), CAIDI (All Outages), and SACI (All Outages)

While Cal Advocates agrees with the initial Staff Draft Proposal inclusion of "all outages" reliability metrics, PG&E disagrees with their inclusion and finds it inappropriate for the following reasons: "(1) It seeks to measure utility failure in conditions beyond utility control and design standards; (2) the number of Major Event Days within PG&E's territory within a year are not predictable, which creates the inability to establish indicator-levels or assess performance trends to signal failure beyond reasonable or minimum levels of service; and (3) Inclusion renders the metric non-benchmarkable, furthering the inability to assess for reasonable or minimum levels of service.[127]

Staff disagrees with PG&E's reasoning for not including Staff's proposed all outages reliability SOMs.

As previously discussed, the definition of MEDs indicates that weather is only one factor that can affect MEDs.[1] A metric that measures failure of a utility's asset on MEDs gives visibility to the vulnerability of the utility's system to extreme weather conditions. It could also reveal other underlying factors that might have led to the measured failure, including deficiencies in the utility's management, maintenance, and operation of that asset.

Staff disagrees with PG&E's written comments that the inclusion of the SAIDI, SAIFI, and CAIDI metrics that evaluate "all outages" is inappropriate. Staff views the "all outages" metrics as an important system-wide indicator for the reliability of the utility's infrastructure under all conditions, including extreme weather patterns. From the customer perspective,

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[126] PG&E's TWG Track 2 informal comments on Draft Staff Proposal, May 11, 2021 at 14.

[127] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 15.

customers depend on the overall reliability of the electric grid and do not necessarily make the distinction between interruptions due to “all outages” and “unplanned” outages.

The “all outages” metrics can signal a need to investigate a potential problem, that otherwise would be attributed to major events instead of deficiencies in PG&E’s management and operation of its system. For example, forests are changing due to climate change. If increasing outages associated with vegetation contact or wires down from branches or trees, it may be that PG&E needs to change their assumptions and policies regarding the use of the vegetation management exception in GO 95[128]. Staff’s proposed process for evaluating SOMs that may lead to recommending PG&E enter into the EOE process will be subject to a comprehensive quantitative and qualitative analysis. This analysis will likely incorporate additional reliability metrics reported to the Commission, and other underlying data that contextualize factors that might be out of the control of the utilities, such as the frequency and severity of MEDs in a given year.

3.7 Staff Recommendations on SAIDI, SAIFI & CAIDI

Staff recommends the Commission adopt our initial proposed SOMs as summarized in Appendix C: Staff recommends that PG&E report “all outages” metrics – SAIDI (All Outages), SAIFI (All Outages), and CAIDI (All Outages) and permutations of these metrics on Unplanned Outages – as reliability SOMs. Staff’s final recommendation modifies our Draft Staff Proposal per PG&E’s informal comments to align the definition of sustained interruptions on which SAIDI, SAIFI, and CAIDI metrics are based with the IEEE 1366 definition: “Any interruption not classified as a part of a momentary event. That is, any interruption that lasts more than five minutes.”[129]

[128] General Order No. 95, Exception 4 of Rule 35, at III-20.

[129] *IEEE 1366- Reliability Indices* Presentation, February 19, 2019, at 6.

4 Public Safety Power Shutoff

4.1 Introduction

PSPS events are an important safety tool of last resort available for IOUs to utilize when dry conditions and/or high wind events create an unacceptably high probability of electrical equipment sparking wildfire. However, PSPS events can negatively impact the safety and livelihood of customers and negatively impact the economy. In summarizing harms caused by PSPS events in 2009, the Commission found: "[A] safe electric system is one which is operated to prevent fires. However, operating a safe system also includes the reliable provision of electricity. Without power, numerous unsafe conditions can occur. Traffic signals do not work, life support systems do not work, water pumps do not work, and communication systems do not work. As the California Legislature recognized in §330(g), "reliable electric service is of utmost importance to the safety, health, and welfare of the state's citizenry and economy."[130]

The Commission gave additional guidance to IOUs on PSPS, emphasizing that, "there is a strong presumption that power should remain on for public safety reasons."[131] In D.19-05-042, the Commission reiterated the need for utilities to identify the public harms of de-energizations and then balance those harms against potential wildfire benefits[132] and further stated utilities must only use power shutoffs as a last resort for wildfire mitigation.[133] As a result, the Commission currently has reporting and mitigation requirements for IOUs to follow in advance of, during, and after PSPS events.

The Commission closely monitors the execution of PSPS events. Commissioners have convened numerous public meetings with utility executives to address PSPS execution and preparedness. In addition, the Commission has taken enforcement action against utilities for failure to comply with PSPS guidelines including the Order to Show Cause in R.18-12-005, and the Order Instituting Investigation on the Commission's Own Motion on the Late 2019 Public Safety Power Shutoff Events (I.19-11-013).[134]

The scope of Track 2 of R.20-07-013 indicates the development of PSPS SOMs should consider, "[r]equirements regarding the management and minimization of Public Safety

[130] D.09-09-030, at 61.

[131] D.09-09-030, at 61.

[132] D. 19-05-042, Appendix A at A24.

[133] D. 19-05-042, Appendix A at A1.

[134] Decision Addressing the 2019 Public Safety Power Shut Off Events by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company. I1911013 (Rev.1), issued on June 3, 2021. Available here: [Decision Addressing Late 2019 PSPS Events]

Power Shutoff (PSPS) events adopted in Rulemaking (R.) 18-12-005, including in D.19-05-042 and D.20-05-051."[135]

Existing Oversight and Enforcement of PSPS

IOU PSPS activities are subject to oversight and enforcement by the Commission. Currently each electric IOU is required to submit a post event report on each PSPS event to the Commission, regardless of whether de-energization has actually occurred. Post events are required to be reported to Safety and Enforcement Division within 10 business days of power restoration that describe the quantitative and qualitative factors the IOU considered in calling, sustaining, or curtailing each PSPS event, among other details. Post event reports are required pursuant to D.19-05-042 and D.20-05-051.[136]

In addition, the aforementioned decisions require the electric IOUs to maintain website updated on a year-round basis regarding efforts to reduce the need for or scope of de-energization events, including, asset and vegetation management, sectionalizing, switching, system hardening, backup power projects, progress on de-energization mitigation efforts, and planned dates of completion.

Starting in 2021, IOUs are required to include in their WMPs specific short, medium, and long-term actions the IOU will make to reduce the impact of and need for PSPS events.[137]

Further, in addition to the proposed SOMs here, "failure to comply" with PSPS protocols is a Triggering Event in Step 1 of the EOE process. [138] Considering 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. Inclusion as a SOM will further incentivize progress on the implementation of mitigation measures to reduce the impact of PSPS events on Californians.

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[135] R.20-07-013, at 2 and 3.

[136] D.19-05-042 Appendix A at A-22 – A-25; and D.20-05-051, Appendix A, at 9-10.

[137] D.20-05-051, Appendix A, at 8-9.

[138] D.20-05-053, Appendix A, at 1.

4.2 Discussion

Other Parties' Suggested PSPS Metrics Considered in the Draft Staff Proposal

In response to PG&E's proposed SOMs, MGRA recommends "PSPS Damage Reports" as a metric to report damages to IOUs' facilities during PSPS events, which demonstrates the resiliency of utilities infrastructure to fire and weather conditions.[139] MGRA notes that the Commission requires the IOUs to collect and report this information pursuant to D.19-05-042. MGRA also suggests tracking weather metrics, such as wind speeds associated with all risk events as a way of normalizing ignition, Wires Down, risk events, outages, and PSPS damage. MGRA recommends Weather Events metric for tracking events that occur during and within the boundaries of National Weather Service High Wind Warnings, High Wind Advisory, and Red Flag Warning areas, as a simple proxy for weather data. MGRA articulates that although these metrics are not ideal, they can provide a baseline that can be compared across utilities. MGRA indicates that utilities are required to report number of utility mile-days that their infrastructure spends under High Wind Warnings and Red Flag Warning conditions, which allows some degree of normalization.[140]

MGRA recommends "PSPS instances found to be unreasonable by Commission standards" as a SOM.[141] MGRA indicates that CPUC is already supposed to determine whether utility PSPS events were reasonable, and it is also tasked with developing reasonableness criteria for de-energization. If the reasonability standards are well-defined and objective, then they could serve as triggering mechanisms for EOE.[142]

MGRA states that regarding wildfire, the only "operational" metrics that would be relevant to safe utility operation would have to do with the protocols surrounding power shutoff. Other metrics, such as risk events, Wires Down, or ignitions are trailing metrics not under the utilities' direct control.[143]

[139] MGRA, March 1st, 2021 Comments, at 8-10.

[140] MGRA, March 1st, 2021 Comments, at 8-10.

[141] MGRA, March 1st, 2021 Comments, at 9.

[142] MGRA, March 1st, 2021 Comments, at 9.

[143] MGRA, March 1st, 2021 Comments, at 4.

MGRA recommends the following factors when considering power shutoff protocols:[144]

- Does the utility have specific shutoff criteria on a circuit-by-circuit (or finer) basis, and are these criteria transparently stated?
- For a given risk event, did the utility adhere to its shutoff criteria, i.e. did the measured weather conditions exceed the thresholds?
- Are shutoff thresholds consistent with real risk of either vegetation contact or damage to equipment from wind gusts exceeding GO 95 design criteria?
- Did the utility's weather measurements correspond to its forecasts?
- Did the utility notify all required customers and partners regarding de-energization and re-energization on a timely basis?

MGRA indicates that many of these factors are (or are supposed to be) included in post-event reporting by the utility, but the Commission has not adopted guidelines on "reasonableness" evaluations. MGRA recommends that the Commission consider a more rigorous and regular review of the utility post-event reports, and the creation of specific operational metrics that can be tracked and compared across utilities.[145]

Staff reviewed MGRA's comments with interest but concluded that this is not the appropriate time to develop the types of metrics that MGRA recommends because the Commission proceedings that are dedicated to this topic are actively deliberating on these issues and failure to comply with PSPS protocols are already covered as Triggering Events under PG&E's EOE process.[146]

Staff recognizes the importance of tracking PSPS Damage Reports and Weather Events metrics as indicators to monitor the conditions of utilities' infrastructure. Reports of damage are already filed pursuant to the existing reporting requirements and, as noted, failure to comply with PSPS Protocols is both a Triggering Event in the EOE process and subject to Commission enforcement.[147]

[144] MGRA, March 1st, 2021 Comments, at 4-5.

[145] MGRA, March 1st, 2021 Comments, at 5.

[146] Step 1 Triggering Event ii "PG&E fails to comply with, or has shown insufficient progress toward, any of the metrics (i) set forth in…Public Safety Power Shutoffs (PSPS) protocols…" D.20-05-053, Appendix A of at 1.

[147] PSPS damage reports.

Parties' Informal Comments on Draft Staff Proposal

In its April 22, 2021 Draft Staff Proposal, Staff proposed that PG&E report on *average* frequency, duration, and number of customers impacted by PSPS event, annually.

MGRA expresses concern that many outcomes related to wildfire are driven by external events rather than by the degree of utility culpability. MGRA indicates that inappropriate application of the EOE process may push PG&E into adopting more aggressive PSPS policy that may not adequately take into account PSPS risks and costs.[148] MGRA suggests coordination and alignment of data collection with Wildfire Safety Division for efficiency and to avoid misinterpretations and inconsistencies.[149]

Although the utilities cannot control weather or vegetation conditions, strategic system improvements and upgrades can be made to reduce the number and severity of PSPS occurrences. Cal Advocates presents an analysis indicating that 0.6 miles of targeted undergrounding in a specific location in a Santa Rosa neighborhood that frequently experiences PSPS occurrences, would eliminate most, if not all, future PSPS occurrences in this neighborhood.[150]

Staff recognizes that weather and vegetation conditions in any given year may alleviate or intensify the need for PSPS events. However, as contemplated in WMPs and RAMPs continuous strategic system hardening, undergrounding, establishing circuit redundancies, establishment of microgrids, and vegetation control measures can be expected to mitigate risks associated with PSPS events and PSPS occurrences (frequency, duration, and/or number of customers impacted) could therefore be expected to trend downward over time. Staff will evaluate these trends as SOMs. Nonetheless, as noted above, Staff is open to considering normalizing SOMs to reduce exogenous variation.

In its informal comments PG&E expresses concern with including customers that have received a PSPS notice but were not actually de-energized. PG&E's comment states, "[f]or those customers that were notified, yet were not de-energized, it is unclear how to determine the duration of impaction."[151] Staff disagrees with PG&E's assessment.

Consistent with Commission's PSPS related reporting requirements: "[t]he electric investor-owned utilities must report on lessons learned from each de-energization event, including instances when de-energization protocols are initiated, but de-energization does not occur, in order to further refine de-energization practices,"[152] Staff recommends that PG&E reports PSPS related SOMs to include measurements regardless of whether de-energization actually occurred.

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[148] MGRA's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 2.1.

[149] MGRA's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 2.2.

[150] Cal Advocates' Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, 2.9.

[151] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 13.

[152] D.19-05-042, Appendix A, at A3.

The reporting period for a PSPS event begins with the first notification of an impending power shut-off. The PSPS ends when the last circuit is restored and customers and critical facilities are notified.[153] Even if a customer is never de-energized during a PSPS event, that household is still under notice that power could be shut off. Customers may prepare for an impending power shut-off by securing back-up power, relocating to a hotel, or by making other preparations. A notice of impending PSPS can be especially impactful to medical baseline and other Access and Functional Needs (AFN) customers who may rely on electricity to power life sustaining or life supporting devices, customers who need to work from home, needs of school-aged children, to name a few scenarios. Businesses, emergency services, and critical infrastructure providers will also be on alert and will make potentially costly preparations due to the PSPS notification. These customer impacts and their disruption to safety, livelihoods, and economy are why SOMs should track impacts of PSPS events regardless of whether or not de-energization occurs.

4.3 Staff Recommendations on PSPS SOMs

Following consideration of parties' informal comments on the Draft Staff Proposal, instead of reporting *average data* on Staff's originally proposed PSPS SOMs, Staff recommends that PG&E report absolute measurements of these metrics on annual basis (number of PSPS events, duration of events in hours, and number of customers impacted). Such an approach will allow Staff to analyze the metrics to delineate exogenous factors that might skew the average results and evaluate the overall trends in PSPS events in terms of duration, frequency and impacted customers over time.

Staff recommends the following three PSPS related SOMs:

1. *Number of PSPS events in a calendar year.*
2. *Duration of each PSPS Event in hours in a calendar year.*
3. *Number of Customers Impacted by each PSPS Event in a calendar year.*

Staff will evaluate the proposed PSPS related SOMs trends over time. PG&E's strategic 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. Even if PSPS events increase in a given year, progress in PG&E's operation performance should be reflected if these PSPS SOMs trend downward over time. Staff may consider approaches to normalize these SOMs to reduce exogenous variation.

[153] D.19-05-042 Appendix A, at A8-A9.

5 Outages due to Vegetation and Equipment Damage

5.1 Outages due to Vegetation and Equipment Damage in HFTD Areas SOMs

Staff recommends that the Outages due to Vegetation and Equipment Damage SOM be specific to Tier 2 and 3 HFTD Areas.[154] Staff considered parties' suggestions and decided to retain its initial proposed definition of this SOMs. Staff includes additional permutations of this SOM to express MEDs and Non-Major Event Days outages, as discussed in the following sub sections.

Refer to Appendix C for a summary of Staff's Proposed SOMs.

5.2 Reporting Requirements

The current Wildfire Safety Plan reporting template developed by the Wildfire Safety Division contains granular categories of electric outage types including vegetation and various types of equipment damage. The specific data on equipment damage-related outages can be aggregated to produce overall outages caused by all equipment damage types in addition to vegetation-related outages.

Similar to other SOMs, Staff recommends that PG&E reports the Outages due to Vegetation and Equipment Damage SOMs on an annual basis and provides historical data of these SOMs with its first report.

5.3 Discussion

In its February 17, 2021 comments in response to PG&E's SOMs proposals, MGRA proposes metrics measuring outages due to vegetation contact or utility equipment damage.[155] MGRA indicates that such metrics provide additional granularity to the Wires Down metric, since Wires Down events can result from either vegetation contact or equipment damage, and an outage due to vegetation contact can be accompanied by either a Wires Down event or a non-wire-down event.[156]

Metrics measuring outages due to vegetation contact or equipment damage can provide visibility to the strength and weaknesses in the following areas: 1) the quality of the utility's vegetation management program, 2) the quality of utility's maintenance program, 3) the condition of the utility's electric assets, 4) the robustness of the utility's circuit protection,

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[154] Decision for Adopting the Work Plan for the Development of Fire Map 2 (D.17-01-009), as modified by Decision Amending the Work Plan for the Development of Fire Map 2 (D.17-06-024). Additional Tier information.

[155] Mussey Grade Road Alliance Reply to the Response of Pacific Gas and Electric Company Regarding Development of Safety and Operational Metrics, February 17, 2021 (MGRA February 17, 2021 Response), at 4.1

[156] MGRA February 17, 2021 Response, at 3.3

and 5) the overall resilience of the utility's circuits. The metrics in this category are lagging metrics measuring safety and reliability performance. Staff agreed with MGRA and recommended adopting Outages due to Vegetation and Equipment Damage as a SOM with additional modifications.

Parties' Informal Comments

In its Draft Staff Proposal, Staff recommended that the Outages due to Vegetation and Equipment Damage SOM be specific to Tier 2 and 3 HFTD Areas.[157] As indicated in the proposal, consistent with the recommended reliability SOMs, Staff defines *System Average* Outages due to Vegetation and Equipment Damage *in HFTD*:

Average number of sustained outages per 100 circuit miles in HFTD per metered customer, in a calendar year,

where each *sustained outage* is defined as:

total number of customers interrupted / total number of customers served

In its informal comments on the Draft Staff Proposal, PG&E stated that it supports the proposed SOM with additional clarification but does not support including MEDs.[158]

As discussed in Section 1.3 above, Staff disagrees with PG&E on excluding Major Event Days metrics. Including Major Event Days metrics, which may contain exogenous factors, can also provide important information on PG&E's operations and system performance, and capture impacts that could result from various factors, such as deficiencies in maintaining and operating the electric systems. As indicated earlier, Staff recognizes the concern regarding exogenous factors in SOMs, and is open to considering approaches to normalize SOMs to control the impacts of external driver events and major events, including extreme weather conditions, earthquakes, etc.

Staff agrees with MGRA that this metric will allow the identification of hazard conditions, and that although a trailing indicator, "it 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."[159]

[157] Decision for Adopting the Work Plan for the Development of Fire Map 2 (D.17-01-009), as modified by Decision Amending the Work Plan for the Development of Fire Map 2 (D.17-06-024). Additional Tier information.

[158] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 19.

[159] MGRA's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 5.

5.4 Staff Recommendations on Outages due to Vegetation and Equipment Damage

Based on TWG discussions and parties' informal comments on the Draft Staff Proposal, Staff recommends that PG&E reports *System Average Outages due to Vegetation and Equipment Damage in HFTD* Major Event Days, as well as Non-Major Events Days outages. Staff maintains its initial definition of this SOM as presented in its Draft Staff Proposal.

In summary, Staff proposes that PG&E reports the following SOMs:

- System Average *Outages due to Vegetation and Equipment Damage in HFTD (Major Event Days)*
- *System Average* Outages due to Vegetation and Equipment Damage *in HFTD (Non-Major Event Days)*
- *System Average Outages due to Vegetation and Equipment Damage* SOMs *(Major Event Days & Non-Major Event Days)* SOMs be specific to Tier 2 and 3 HFTD Areas.[160]

System Average *Outages due to Vegetation and Equipment Damage* in *HFTD* is defined as*:*

Average number of sustained outages per 100 circuit miles in HFTD per metered customer, in a calendar year,

where each *sustained outage* is defined as:

total number of customers interrupted / total number of customers served

For the *Outages due to Vegetation and Equipment Damage in HFTD (Major Event Days & (Non-Major Event Days)* SOMs, PG&E should delineate outages due to contact with vegetation versus outages caused by equipment, and distribution versus transmission assets. For equipment damage-related outages, the metrics should also be segregated by overhead versus underground.

[160] Decision for Adopting the Work Plan for the Development of Fire Map 2 (D.17-01-009), as modified by Decision Amending the Work Plan for the Development of Fire Map 2 (D.17-06-024). Additional Tier information.

6 Electric System

In its Draft Staff Proposal, which was circulated to the TWG for informal comments, Staff has initially proposed Wires-Down and Inspection-Compliance Related SOMs, outlined in the following sub-sections. Staff proposes the following eleven SOMs for use as Triggering Events for the purpose of PG&E's EOE process:

1. *Wires Down (Major Event Days)*
2. *Wires Down (Non-Major Event Day)*
3. *Wires Down in HFTD (Red Flag Warning Days)*
4. *Overhead Distribution Patrols Compliance in HFTD Areas,*
5. *Overhead Distribution Detailed Inspections Compliance in HFTD Areas,*
6. *Overhead Transmission Patrols Compliance in HFTD Areas,*
7. *Overhead Transmission Detailed Inspections Compliance in HFTD Areas*
8. *Distribution Vegetation/Conductor Clearance Inspections Compliance in HFTD Area*
9. *Transmission Vegetation/Conductor Clearance Inspections Compliance in HFTD Area*
10. *Backlog Compliance Metrics*
11. *Electric Emergency Response Time* (Proposed by PG&E)

Refer to Appendix C for a summary of Staff Proposed SOMs, including modified Wires-Down SOMs and additional Vegetation/Conductor Clearance Inspections SOMs, based on suggestions made by parties in their informal comments on the Draft Staff Proposal.

6.1 Staff Proposed Wires Down and Inspection Compliance Related SOMs

6.1.1 Wires Down Related Metrics

In its January 15, 2021 response to the November 17 Assigned Commissioner's Ruling Regarding Development of Safety and Operational Metrics, PG&E proposes "Transmission and Distribution Wires Down" metric as a safety measure relevant to both to wildfire risks and the risk of failure of electric overhead assets.[161]

MGRA objects to PG&E's proposed metric stating that "…the wires-down data omit wires-down data from Major Event Days…," while the majority of wildfire ignitions occur on Major Event Days, of which major fire weather events are a subcategory.[162] MGRA indicates that PG&E's wires-down does not measure how robust utility infrastructure is

[161] PG&E's ACR Response, at 13.

[162] MGRA's Comments on the response of Pacific Gas and Electric Company regarding development of safety and operational metrics (MGRA February 17, 2021 Response), February 17, 2021 (late-filed authorized), at 3.3.

when exposed to fire weather conditions, which makes it an ineffective metric for Triggering Events or tracking data relevant to wildfire risk.[163]

Staff agrees with MGRA that these metrics could provide supplemental data "to normalize for year-to-year and utility-to-utility differences in weather stress that can lead to ignitions, Wires Down, risk events, outages, and PSPS damage." MGRA suggests a simple proxy for weather data to provide a baseline across utilities is whether events occur during and within the boundaries of High Wind Warning, High Wind Advisory, and Red Flag Warning areas.

MGRA also proposes a "Wires Down in HFTD during MEDs and RFW Days" metric. Staff agrees with MGRA regarding this metric and recommends adopting Wires Down in HFTD during MEDs and RFW Days as a SOM for use as Triggering Events for the purpose of PG&E's EOE process. Wires down in these situations are risk drivers that PG&E should make progress in reducing. As such, they are suitable for SOMs in the EOE process. For example, wire down tracking started at PG&E in 2010 and developed into a corporate public safety metric in 2012.[164] The metric will result in an annual tracking of all such events involving transmission or primary distribution conductors that contact the ground or a foreign object, such as, structure, vehicle, tree, etc.

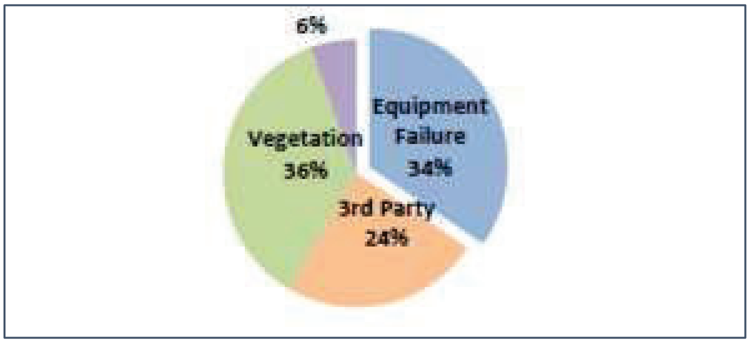
Analyzing trend data such as increase or decrease in the number of Wires Down events per year may indicate problem spots on distributions and transmission lines. If Staff sees troubling trends in the SOM report, Staff can consult with the Wildfire Safety Division (WSD) and review their data, which is also suitable for use as a Triggering Event in the EOE process[165]. Analysis of these SOMs in conjunction with the more substantial data being collected by WSD can be used as a leading indicator to predict future potential failures. Historically, as reported by utilities, wire down events were broken down as one third being caused by vegetation, one third by equipment failure and one quarter caused by a third party.

[163] MGRA February 17, 2021 Response, at 3.3.

[164] Hayes, Scott et al., Pacific Gas & Electric Company, *Wires Down Improvement Program at PG&E*, Western Protective Relay Conference 2015.

[165] Appendix A of Decision 20-05-053, at 1.

Figure 2: PG&E Wires Down Categorized by Risk Driver (Cause) 2012-2014 Excluding Major Event Days)



By tracking wires down caused by all known and unknown causes, broken down by distribution and transmission systems and their segments, the Commission will have broader ability to determine whether utility operations and capital investments are resulting in safety improvements as promised in the IOUs annual Wildfire Mitigation Plans. Tracking Wires Down will be important metrics for tracking utilities' efforts at system hardening. By monitoring whether system hardening investments result in a reduction in equipment failures, including wires down, effective reductions in wildfire safety can be demonstrated transparently.

6.1.2 Wires Down (Major Events Days) in HFTD

In the Draft Staff Proposal, Staff initially proposed Wires Down (Major Event Days) in HFTD Areas SOMs. Based on the May 11, 2021 parties' informal comments on the Draft Staff Proposal, Staff modified the initial proposed definition of Wires Down SOMs to address some gaps identified in the IOUs' proposed definitions that were provided in their informal comments.

Definition for Wires Down

When the original SPMs were adopted in D.19-04-020, the term "Wires Down" was not explicitly defined. Without an explicit definition, "Wires Down" was subject to interpretation and inconsistent reporting. For example, a conductor could become detached from its attachment point on the power pole or transmission tower without breaking and the energized conductor could then come into contact with vegetation or the power pole (or transmission tower). Sparks or molten metal could then fall to the ground to cause a fire. Or, the detached but unbroken energized conductor could drop down to such low level that it would become an electrocution hazard or a hazard to vehicles without touching the ground. Clearly a definition of wire down was needed to capture these scenarios.

In the January 15, 2021 SOMs proposal, PG&E proposed the following definition for wires down:

"Instances 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)"[166]

PG&E's definition is inadequate as it implies that an energized conductor must rest on top of the ground or a foreign object for it to be considered a downed conductor. An energized high voltage conductor that comes down to an inch above the ground, but not resting on the ground, would not count as a wire down event under this definition.

Conductors on a broken or severely leaning power pole that is only prevented from touching the ground due to supporting tension from adjacent poles would not count as a wire down event even though the conductor could come close to the ground.

SCE proposed in its informal comments on May 11, 2021 this definition for wire down:

"A wire down event is defined as an event that satisfies one or more of these conditions:

1. conductor strikes the ground,

2. Conductor falls on an object (e.g., car, fence, house, etc.) that is not intended to support a conductor and does not contact the ground,

3. Conductor falls to a distance of 6 feet or less to the ground and does not strike the ground or an object listed in 2."[167]

SCE's definition is also inadequate for the following reasons:

1. A conductor that detaches from its attachment point and drops down to above 6 feet from the ground would not qualify as a wire down event. Under this SCE definition, an energized high voltage conductor could drop down to 1" from the top of the balcony of a building without triggering this metric. Residents of the building could touch the energized conductor. Same hazard would apply if the balcony was changed to a rooftop. Someone working on the rooftop could touch the energized conductor.

2. The overhead conductors on a severely leaning power pole may not trigger the wire down metric using this SCE definition. For example, high voltage conductors on a severely leaning or broken power pole may be prevented from touching the ground or coming to within 6 ft of the ground due solely to the tension on the conductors provided by intact adjacent power poles. For all intents and purposes, the conductor on the power pole is not supported and should be presumed to be a downed conductor.

3. The 6-foot clearance threshold is inadequate. Vehicles could drive by and hit the conductor. Passersby could touch the conductor.

[166] PG&E's ACR Response, at 13.

[167] SCE's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021.

Sempra suggested in its May 11, 2021 informal comments this modification to the wire down definition proposed by SPD staff:

"SDG&E recommends modifying conditions 1 and 2 to include '...a conductor comes in contact with the ground or foreign object.' SDG&E also recommends removing condition 3."[168]

Staff agrees with the suggestion to modify conditions 1 and 2 to include "...a conductor comes in contact with the ground or foreign object." However, Staff disagrees with the suggestion to remove Condition 3 in the original SPD definition for the same reasons given previously when discussing the SCE definition. Condition 3 in the SPD definition is intended to capture hazardous conditions where the conductor can come dangerously close to the ground or rooftop without coming in contact with them.

Some illustrative hazardous scenarios involving high voltage overhead conductors that should be captured by the definition for a wire down event include the following. These are illustrative examples, but are by no means exhaustive scenarios:

1. During a heavy windstorm, a broken tree limb falls onto an overhead circuit. The conductor is not broken, but the force or weight of the tree limb exerted on the conductors pulls the conductors close to ground level or close to a rooftop, but the conductor is not touching the ground or the rooftop.
2. A wooden power pole leans dangerously because of either rot at the base of the pole or soft ground. The power pole leans dangerously close to the ground but is not touching the ground. Tension on the conductors provided by intact adjacent poles is preventing the conductors from touching the ground.
3. A wooden power pole is rotten at the top and breaks at the top of the pole with the crossarm still attached. The conductors are still attached to the crossarm, but they come near the ground without touching the ground. Tension on the conductors provided by intact adjacent poles is preventing the conductors from touching the ground.
4. The crossarm (or an insulator pin on the crossarm) on a power pole becomes broken and a conductor dangles seven feet above a road. A large truck drives across the road and hits the energized conductor. Or, a person walking nearby could reach up and touch the energized conductor.
5. Some supporting attachment point, for example a C-hook on a transmission tower, is broken and the intact high voltage conductor comes loose or loses tension and makes contact with the transmission tower, creating sparks that cause a wildfire.
6. An overhead primary distribution conductor becomes detached from the crossarm and rests on the secondary distribution or communication conductors on the same span without falling to the ground. The primary conductor then sends primary distribution

[168] Sempra's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021.

level voltage down the secondary distribution or communication conductors and into residences, resulting in structural fires.

In its Draft Staff Proposal, Staff initially recommended that a *Wires Down event* is an event that satisfies one or more of these conditions:

- *A conductor or splice becomes broken due to mechanical failure, whether or not it comes in contact with the ground,*
- *A conductor is dislodged from its intended design position due to either malfunction of its attachment points and/or supporting structures or contact with foreign objects (including vegetation), regardless of whether the conductor is broken or whether it comes in contact with the ground, or*
- *A conductor's distance from the ground, structures, or objects (not including vegetation) falls below applicable minimum clearances specified in General Order 95.*

Given the above discussions, Staff proposes two additional conditions: *A conductor comes into contact with communication circuits, guy wires, or conductors of a lower voltage, and a power pole carrying normally energized conductors leans by more than 45 degrees in any direction relative to the vertical reference when measured at ground level.*

Staff's final recommendation is that Wires Down SOM is defined as follows:

> *A Wires Down event occurs when a normally energized overhead primary or secondary distribution or transmission conductor satisfies one or more of these conditions:*
>
> *1. A conductor or splice becomes broken,*
>
> *2. A conductor is dislodged from its intended design position due to either malfunction of its attachment points and/or supporting structures or contact with foreign objects (including vegetation),*
>
> *3. A conductor's distance from the ground, structures, or foreign objects (not including vegetation) falls below applicable minimum clearances specified in General Order 95,*
>
> *4. A conductor comes into contact with communication circuits, guy wires, or conductors of a lower voltage, or*
>
> *5. A power pole carrying normally energized conductors leans by more than 45 degrees in any direction relative to the vertical reference when measured at ground level.*

This *Wires Down* event definition excludes vegetation growth-related clearance violations in which the conductor does not otherwise violate the five conditions listed above. This definition includes service drops.

Accordingly, Staff's final recommendation on the definition for *Wires Down (Major Event Days) in HFTD Areas* SOM is as follows:

Number of Wires Down events on Major Events Days involving either overhead primary or secondary distribution or overhead transmission circuits divided by total circuit miles of overhead primary distribution and transmission lines x 1,000, in a calendar year.

Staff's proposed definition of a *Wires Down event* applies to this metric.

For this metric, overhead primary distribution and transmission circuit miles are counted separately and then added together even if they are found on the same spans.

6.1.3 Wires Down (Non-Major Events Days)

In the Draft Staff Proposal, Staff recommended a SOM for Wires Down Major Event Days, Red Flag Warning days, in HFTD. In their May 11, 2021 Informal Comments, PG&E did not support these metrics, preferring instead to use its own definition of Wires-Down metric included in PG&E's January 15, 2021 proposal,[169] which differs from Staff's definition. In opposing Staff's proposal, PG&E argued that including Major Event Days would result in "exemplary" performance in "a year with minimal extreme weather events" with "above average extreme weather events [driving]…adverse performance."[170]

Staff does not agree with PG&E's reasoning for objecting to the Wires Down Major Event Days metric. Since design and maintenance requirements for overhead circuits as specified in GO 95 do not reference Major Event Days, there is no direct linkage between a circuit failing on a Major Event Days 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 Major Event Days gives visibility to the vulnerability of PG&E's overhead electric assets to extreme weather events. As indicated earlier, (See Section 1.3 above), this metric has relevance in the context of risk-based decision making and the expectation for a utility to address safety and reliability risks, notwithstanding extreme weather events. Although a Wires Down Major Event Days 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.

Staff recognizes PG&E's concern about being held accountable to weather events or other exogenous factors out of the utilities' control. MGRA writes "As noted by PG&E during the May 4th meeting, valuable information regarding system aging and vegetation

[169] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 20-21.

[170] PG&E's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 10.

contacts can be collected as all times. What is important is to have Major Event Days included in this sample, possibly as a second wires down metric or as a supplemental field, so that MED wires down can be differentiated from non-MED wires down.[171]"

Collecting both Major Event Days and Non-Major Event Days Wires Down metrics addresses MGRA's concern about missing the influence of Major Event Days on Wires Down Events, and collecting data without will allow PG&E and Staff to assess the difference between Wires Down performance with and without extreme weather events.

As such Staff proposes and additional SOM to capture non-Major Event Days events.

Staff proposes *Wires Down (Non-Major Event Days) in HFTD Areas* SOM be defined as follows:

> *Number of Wires Down events on Non-Major Events Days involving either overhead primary or secondary distribution or overhead transmission circuits divided by total circuit miles of overhead primary distribution and transmission lines x 1,000, in HFTD Areas, in a calendar year.*

Staff's proposed definition of a *Wires Down event* applies to this metric.

For this metric, overhead primary distribution and transmission circuit miles are counted separately and then added together even if they are found on the same spans.

6.1.4 Wires Down in HFTD Areas (Red Flag Warning Days)

In the Draft Staff Proposal, Staff initially proposed *Wires Down Red Flag Warning Days* in HFTD Areas SOMs. As discussed above, Staff's final recommendation on the definition of "*Wires Down*," also applies to this metric.

Wires Down Red Flag Warning Days in HFTD Areas SOM is defined as follows:

> *Number of Wires Down events on Red Flag Warning Days involving either overhead primary or secondary distribution or overhead transmission circuits divided by total circuit miles of overhead primary distribution and transmission lines x 1,000, in HFTD, in a calendar year.*

For this metric, overhead primary distribution and transmission circuit miles are counted separately and then added together even if they are found on the same spans.

6.1.5 Patrols and Detailed Inspections Compliance (HFTD)

Utilities report maintenance related metrics on annual basis as part of their Wildfire Mitigation Plans, separately for distribution and transmission systems. Some of the key metrics track total miles inspected and inspection findings. These metrics are broken into 28 sub-metrics recording various types of patrols and inspections to better inform the Commission on utility operations and grid conditions.

[171] MGRA's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 7.

Circuit patrols and inspections are frontline defenses established to prevent hazardous conditions from developing and potentially escalating into serious incidents. These metrics track how well utilities are inspecting and maintaining their distribution and transmission assets including conductors, connectors, poles, towers, crossarms and other essential equipment to enable the safe operation of their assets. Since inspections serve as an early warning bell to detect emerging hazardous conditions and prevent them from escalating into serious incidents, this metric has both lagging-indicator and leading-indicator characteristics. These metrics track the number of occurrences in the past calendar year in which the utility inspected or patrolled the overhead circuits less frequently than scheduled.

In its Draft Staff Proposal, Staff initially recommended four separate metrics as SOMs suitable for use as Triggering Events for the purpose of PG&E's EOE process:

- *Overhead Distribution Patrols Compliance in HFTD Areas,*
- *Overhead Distribution Detailed Inspections Compliance in HFTD Areas,*
- *Overhead Transmission Patrols Compliance in HFTD Areas,*
- *Overhead Transmission Detailed Inspections Compliance in HFTD Areas*

Staff's initial definition, which was included in the Draft Staff Proposal for *Patrols and Inspections Compliance in HFTD, was as follows*:

> *Total circuit miles of detailed inspections (or patrols) that fell below the minimum detailed inspection (or patrol) frequency requirements divided by the total circuit miles of required detailed inspections (or patrols), in HFTD area in past calendar year.*

On its May 11, 2021 informal comments on the Draft Staff Proposal, PG&E pointed out that it tracks overhead electric inspections by the number of structures inspected rather than by circuit miles. Staff agrees that the metrics for overhead electric patrols and inspections should be modified to measure in units of structures that missed inspection rather than in circuit miles. PG&E also suggested combining these four metrics into one. Staff disagrees that these four inspection related metrics should be combined into one metric, since there is value in having this level of granularity to measure compliance of patrols versus detailed inspections to help pinpoint deficient areas. Likewise, there is value in distinguishing inspection of distribution versus transmission infrastructures for the same reason. As a result of the change to measure electric inspections in units of structures that missed inspection, Staff proposes two new Vegetation/Conductor Clearance Inspection Compliance SOMs in HFTD since vegetation-related inspections are recorded by circuit miles.

Accordingly, Staff's final recommendation is that *Overhead Patrols and Inspections in HFTD is defined as follows*:

> *Total number of overhead electric structures that fell below the minimum patrol (or inspection) frequency divided by the total number of overhead electric structures that required patrols (or inspections), in HFTD area in past calendar year.*

where,

For distribution, "Minimum patrol (or inspection) frequency" refers to the frequency of patrols (or inspections) of circuits as specified in GO 165.

"Structures" refer to electric assets such as transformers, switching protective devices, capacitors, lines, poles, etc.

This modified definition (changing "circuit miles" to structures) also applies to the SOMs on Overhead Transmission Patrols and Detailed Inspections in HFTD Areas.

For transmission, "Minimum patrol (or inspection) frequency" refers to the frequency of circuit patrol (or inspection) requirements, as applicable.

Staff proposes two new SOMs on Vegetation/Conductor Clearance Inspection:

- *Distribution Vegetation/Conductor Clearance Inspections in HFTD Areas*, defined as follows:

  Total circuit miles of vegetation/conductor clearance inspection on distribution circuits that fell below the minimum vegetation management inspection frequency divided by the total distribution circuit miles that required inspections, in HFTD area in past calendar year.

- *Transmission Vegetation/Conductor Clearance Inspections in HFTD Areas*, defined as follows:

  Total circuit miles of vegetation/conductor clearance inspection on transmission circuits that fell below the minimum vegetation/conductor clearance inspection frequency requirements divided by the total transmission circuit miles that required inspections, in HFTD area in past calendar year.

6.1.6 Backlog Compliance Metrics

At the January 28, 2021 workshop on SOMs, Cal Advocates suggested using backlog metrics to measure completion of work orders.[172] Since inspection backlog metrics are subsumed into Staff's proposed SOMs, *Patrols Compliance in HFTD Areas, and Detailed Inspections Compliance in HFTD Areas*, introducing a metric that measures the backlogs of overdue maintenance, and corrective work orders, including those generated as a result of patrols and inspections, fills the remaining gap.

A Backlog Compliance metric also covers work orders generated by electric system hardening and Enhanced Vegetation Management programs and measures the number of overdue work orders and the percentage of such overdue work orders in the past calendar year.

The longer system maintenance is delayed or the longer a deficient or unsafe condition remains uncorrected the greater will be the likelihood for the condition to result in an actual

[172] PG&E's March 1, 2021 Additional Comments at 2.

incident. Additionally, when an unsafe or deficient condition is corrected early, the extent of deterioration to the equipment will be less, which could reduce both the likelihood and the potential consequence of a resulting incident.

This type of metric has both lagging and leading characteristics; lagging with respect to the failures to complete work orders on time, which is predominantly an operational performance issue, and leading relative to potential incidents that could occur due to the failures to complete work orders on time.[173]

In its Draft Staff Proposal, Staff recommended adopting *Backlog Compliance Metrics for overhead distribution circuits and for overhead transmission circuits in HFTD Areas,* as a category of SOMs suitable for use as Triggering Events for the purpose of the EOE process. *Backlog Compliance Metrics* is defined as

> *Total number of overdue overhead work orders in High Fire Threat Districts that exceeded the maximum allowable/allotted time frame to complete the work order divided by the total number of closed or still-open electric work orders, in past calendar year, evaluated at the end of the year.*

On their May 11, 021 informal comments on the Draft Staff Proposal, PG&E opposes including the vague term "risk mitigation" in the specification for work orders. Staff agrees that this term is too vague for use in specifying work orders. Accordingly, Staff modified the definition *Backlog Compliance Metrics* to remove the words "risk mitigation" from the specification for this metric.

Staff Proposed Backlog Compliance Metrics in HFTD is now defined as follows:

> *Total number of overdue overhead electric work orders in high fire threat districts that exceeded the maximum allowable/allotted time frame to complete the work order divided by the total number of closed or still-open overhead electric work orders, in past calendar year, evaluated at the end of the year.*
>
> where,
>
> *"Work Orders" include maintenance, and corrective work orders (including those generated as a result of patrols and detailed inspections), electric system hardening, and Enhanced Vegetation Management programs.*

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[173] TURN recommended WSD Compliance Actions as a triggering SOM, focusing on the number of Category 1-Severe findings, while all categories of defects be included as data points to provide context to the overall number and severity of the defect. WSD Compliance Actions are already encompassed as triggers under the EOE process. As such, Staff does not support adopting this as a SOM as it would be redundant with WSD enforcement activities. TURN's March 1, 2021 Additional Comments, at 12.

6.1.7 Electric Emergency Response Time

PG&E proposes an "Electric Emergency Response Time" metric as a safety measure relevant to the risk of failure of electric distribution overhead assets, as well as a quality of service and management measure, and defines this as follows:[174]

> Percentage of time that utility personnel respond (are on site) within 60 minutes after receiving a 911 call (electric related), with onsite defined as arriving at the premises to which the call relates.

Staff agrees with PG&E's proposed *Electric Emergency Response Time* as a SOM suitable for use as Triggering Event for the purpose of PG&E's EOE process.

6.2 Reporting Requirements

Assembly Bill (AB) 1054 (Holden, Chapter 79 statutes of 2019) requires that IOUs submit Wildfire Mitigation Plans to the Wildfire Safety Division, which requires IOUs to annually report on metrics that relate to the following wildfire risk categories: 1) environmental conditions, 2) grid conditions, and 3) wildfire impacts.[175]

As part of the 2020 Wildfire Mitigation Plans filings, the Wildfire Safety Division began requiring IOUs to submit specified geographic information system (GIS) data related electrical infrastructure, risk mitigation, and incident. This information is now required on a quarterly basis.[176] As noted previously, "insufficient progress toward, any of the metrics…set forth in its approved wildfire mitigation plan" may be used as a Triggering Event in the EOE process.[177]

To supplement oversight already underway by Wildfire Safety Division, Staff recommends that a subset of electric risk-related metrics be included in the SOMs. In this way the SOMs can act as "indicator lights" on electrical risks. If the SOMs trends look troubling, Staff can seek additional information from Wildfire Safety Division (soon to be the Office of Energy Infrastructure Safety), the Electric Safety Reliability Branch, and the Wildfire Safety Enforcement Branch to substantiate whether the SOMs metrics and/or other EOE process metric substantiate a Triggering event.

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[174] PG&E's ACR Response, at 13.

[175] Appendix A includes an excel workbook with details on WSD reporting metrics divided by the three categories, with two categories, grid conditions and wildfire impacts, broken down separately for distribution systems and transmissions systems.

[176] Wildfire Safety Division Data Standard v2.

[177] Step 1 Triggering Event ii "PG&E fails to comply with, or has shown insufficient progress toward, any of the metrics (i) set forth in its approved wildfire mitigation plan…" D.20-05-053 Appendix A, at 1.

Staff recommends that PG&E reports Staff's proposed electric system related SOMs on an annual basis and that PG&E provide all historical annual data with its first SOM submission.

6.3 Staff Recommendations on Electric Related SOMs

Based on consideration of parties' informal comments on the Draft Staff Proposal and TWG feedback, for the reasons articulated above, Staff modified the definitions for Wires Down, and Patrols and Inspections SOMs. Staff also proposes two additional metrics on Vegetation Line Clearance Inspections Compliance SOMs. Refer to Appendix C for the complete list and definitions of Staff's proposed electric system related SOMs.

7 Ignitions & Wildfires

PG&E proposes a "Reportable Fire Ignitions" metric as a safety measure relevant to wildfire risks, defined as follows:

> Powerline-involved fire incidents annually reportable to the CPUC per D.14-02-015 and within the utility's High Fire Threat District. A reportable fire incident includes all of the following: (1) Ignition is associated with the utility's powerlines (both transmission and distribution); (2) something other than the utility's facilities burned; and (3) the resulting fire traveled more than one meter from the ignition point"[178]

TURN agrees with PG&E's proposed SOM here and recommends additional SOMs for Acreage Burned and WSD Compliance activities. TURN states that even if the number of reportable ignitions falls, if one of the ignitions caused a large wildfire, PG&E should be subject to stricter oversight and enforcement. Including both reportable ignitions and acreage burned gives context to the reportable ignitions metric and may provide a better reflection of the larger wildfires happening in PG&E's territory, according to TURN.[179] Staff agrees with TURN that this additional data regarding the impact should be reported. WSD collects acreage burned, fatalities, structures damaged or destroyed, and OSHA reportable injuries reported as part of their Wildfire Mitigation Plan reporting requirements. All WFMP metrics can be used as a Triggering Event under Step 1 of the EOE process.[180] As noted in the introduction of this section, the redundancy associated with collecting these metrics as SOMs provides for rigorous oversight and enforcement on wildfire related metrics. In the event Staff observes a concerning trend on ignitions, Staff can consult with Wildfire Safety Enforcement Branch and WSD, evaluate their data and make appropriate recommendations to the Commission associated with EOE process.

TURN proposes a refinement of PG&E's proposed reportable fire ignitions metric to only include ignitions in the HFTD that occur on red flag warning days. TURN indicates that this metric would demonstrate a reduction in ignitions most likely to result in a catastrophic wildfire.[181] Again, Staff agrees with TURN that this would be an excellent metric to collect and track. When WSD collects their ignition data for their GIS database, an attribute entitled, '[Red Flag Warning] RFW status' is entered along with it. "Insufficient Progress" on the GIS data, like all WFMP data, can also be used as a Triggering Event in Step 1 of the EOE process at the Commission's discretion.

SCE proposes CPUC-reportable ignitions in High Fire Risk Area (HFRA). SCE states that it would be support including this measure in the SPMR and recommends providing the

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[178] PG&E's ACR Response, at 13.

[179] TURN March 1, 2021 Additional Comments, at 11.

[180] Step 1 Triggering Event ii "PG&E fails to comply with, or has shown insufficient progress toward, any of the metrics (i) set forth in its approved wildfire mitigation plan…" D.20-05-053 Appendix A, at 1.

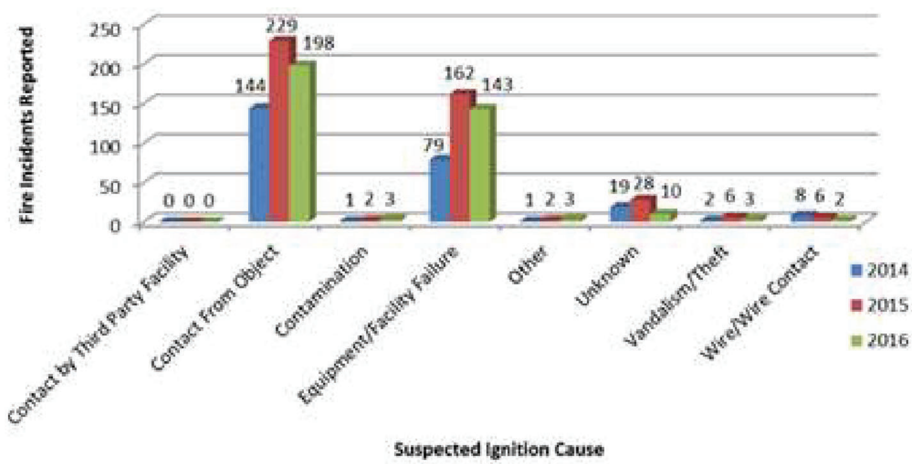
[181] TURN March 1, 2021 Additional Comments at, 11.

data for Fire Ignitions in the same format as the Wildfire Mitigation Plan, which includes additional categories. SCE indicates that in this case the granularity of reported metrics better corresponds to tranches used to define risks and risk mitigations, which is accomplished by including the additional sub-categories for this metric.[182]

Staff agrees with SCE's recommendations and proposes adopting CPUC-Reportable Ignitions in HFTDs as a SOM for use as Triggering Events for the purpose of PG&E's EOE process.

Analyzing and trending data such as increase or decrease in the number of ignitions in HFTD caused by utility equipment per year may indicate problem spots on distribution and transmission systems and are a leading indicator of future potential equipment failures. By tracking ignitions caused by utility equipment, broken down by distribution and transmission systems and their segments, the Commission will have broader ability to determine whether utility operations and capital investments are resulting in safety improvements. Figure 3 below shows the suspected primary causes of ignitions in PG&E service territory during the years 2014 – 2016.[183]

Figure 3: PG&E Fire Incidents by Suspected Ignition Cause



[182] SCE March 1, 2021 Additional Comments, at 9.

[183] 2014-2016 Fire Incident Data Collection.

7.1 Ignitions Related SOMs

In its Draft Staff Proposal, which was circulated to the TWG for informal comments, Staff initially has proposed CPUC-Reportable Fire Ignitions in HFTD Related SOMs, outlined in the following sub-sections.

Staff views a CPUC-Reportable Fire Ignitions in HFTD Areas metrics as consistent with current global best practices in the electric utility industry and meriting Commission adoption. D.14-02-015 adopted a "Fire Incident Data Collection Plan" that requires certain IOUs to collect and annually report certain information that would be useful in identifying operational and/or environmental trends relevant to fire-related events.

7.1.1 CPUC-Reportable Ignitions in HFTD Areas

CPUC-Reportable Fire Ignitions in HFTD Areas are *Ignition events in HFTD* reported to the Commission pursuant to D.14-02-015, whether or not the utility's infrastructures were preliminarily or ultimately determined by either the utility or the Authorities Having Jurisdiction (AHJs) to have played a role in either initiating or propagating the ignitions.

CPUC-Reportable Ignitions in HFTD Areas measures the number of reported ignitions in HFTD areas in a calendar year. The metric distinguishes ignitions caused by transmission from distribution circuits. The utility shall also express the number of reported ignitions as a percentage of circuit miles, separately for transmission and distribution circuits.

Staff recommends four metrics for CPUC-Reportable Ignitions in HFTD Areas, reported in the past calendar year, to be defined as follows:

- *Number of CPUC-Reportable Ignitions HFTD Areas (Distribution): Number of CPUC-Reportable Ignitions involving overhead distribution circuits in HFTD Areas.*
- *Number of CPUC-Reportable Ignitions HFTD Areas (Transmission): Number of CPUC-reportable Ignitions involving overhead transmission circuits in HFTD Areas.*
- *Percentage of CPUC-Reportable Ignitions in HFTD (Distribution): (Number of CPUC-Reportable Ignitions involving overhead distribution circuits in HFTD) divided by (total circuit miles of overhead distribution circuits in HFTD).*
- *Percentage of CPUC-Reportable Ignitions in HFTD (Transmission): (Number of CPUC-Reportable Ignitions involving overhead transmission circuits in HFTD) divided by (total circuit miles of overhead transmission circuits in HFTD).*

Distribution and transmission circuit miles are counted separately if they are on the same spans.

7.2 Discussion

MGRA supports inclusion of an ignition metric, noting: "[i]t is very important to note, however, that CPUC-reportable ignitions do not include major fires under investigation or litigation. Staff may want to include these additional fires, as they represent the lion's share of reported fatalities and damage."[184] This is a similar concern to that raised by MGRA in their March 29th comments on Wildfire Mitigation plans where they said, "Official ignition data collection under CPUC auspices was begun in 2015. One important point of compromise in the original negotiations was that utilities were allowed to withhold any ignition data for any event that they contested was a utility-caused ignition or that was under criminal investigation or civil litigation, in order to preserve their right against self-incrimination."[185]

Staff agrees that including ignitions that are under investigation or subject to litigation is appropriate. To that end, Staff recommends expanding the definition adopted in D.14-02-015 to include CPUC reportable ignitions and any ignitions determined by the Authority Having Jurisdiction investigation to originate from utility infrastructure. This will encompass ignitions that remain the subject of ongoing litigation or other situation where PG&E has yet to formally acknowledge responsibility for a specific ignition.

7.3 Staff Recommendation on Ignitions Related SOMs

Staff final recommendation is to define the *CPUC-Reportable Ignitions in HFTD* SOMs as: *the number of CPUC-Reportable ignitions and any other ignitions determined by the Authority Having Jurisdiction to originate from utility infrastructure.*[186]

Refer to Appendix C for Staff's final recommendations on the definitions of the CPUC-Reportable Ignitions in HFTD SOMs.

[184] MGRA's Informal Comments on Staff Draft Proposal on Phase I Track 2 issues, May 11, 2021, at 8.

[185] Mussey Grade Road Alliance Comments on 2021 Wildfire Mitigation Plans of PG&E, SCE, and SDG&E, at 87.

[186] The number of powerline-involved fire incidents annually reportable to the CPUC per Decision 14-02-015. A reportable fire incident includes all of the following: 1) Ignition is associated with a utility's powerlines and 2) something other than the utility's facilities burned and 3) the resulting fire traveled more than one meter from the ignition point.

8 Natural Gas System

Catastrophic circumstances arising from natural gas incidents are fortunately rare. Many safety improvements have been made to California's gas infrastructure since the 2010 San Bruno rupture.[187] Continuation of this safety performance relies on diligent adherence to safe operating practices. The following Staff proposed SOMs aim to measure the IOUs' performance of those activities.

The primary cause of gas safety incidents is loss of containment from the pipeline, which may be due to failure of control devices, mechanical damage from excavation, or degradation of the pipe's material or sealants. Most containment losses result in minor gas leaks which do not ignite but require repairs according to schedules set by the CPUC General Order 112-F.[188]

Staff accepts PG&E's proposed SOMs with some modifications and additions as discussed in the following sections.

8.1 Natural Gas System Related SOMs

In its Draft Staff Proposal, which was circulated to the TWG for informal comments, Staff initially has proposed Natural Gas System Related SOMs, outlined in the following sub-sections. Based on the parties' suggestions, Staff has modified some of its initial proposed SOMs as discussed in the following sub sections.

Refer to Appendix C for a summary of Staff Proposed SOMs, including modified SOMs based on suggestions made by parties in their informal comments on the Draft Staff Proposal.

8.1.1 Gas Dig-Ins

The 2020 PG&E RAMP report indicates that excavation dig-ins are a leading cause of pipeline loss of containment incidents.[189] A frequent result is a gas leak that may require evacuation of the neighborhood and closure of nearby businesses until repairs can be made. In rare cases a rupture with fire can occur. Since 2010, there have been two PG&E transmission line dig-ins by third-party excavators that resulted in the death of the equipment operators themselves.[190]

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[187] D.12-12-030, *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering*.

[188] CPUC General Order 112-F, Section 143.2.

[189] PG&E 2020 RAMP Report, Figure 7-1.

[190] Data from Pipeline and Hazardous Materials Safety Administration, US Dept. of Transportation.

While gas companies cannot prevent all dig-ins, safety regulations require them to conduct public awareness campaigns about the Underground Service Alert program as part of their damage prevention effort.[191] Contractors who are planning excavations are expected to call 811 to create Underground Service Alert tickets which inform all utilities of the pending excavation. Utilities must respond to Underground Service Alert tickets by marking the location of buried pipelines for the excavators to see. The excavator must then follow safe digging protocols, such as hand-digging within a safe distance of the underground pipe. If a utility fails to respond with accurate marking in the time window required, they may have contributed to a dig-in.

PG&E proposes the *Gas Dig-In Rate* metric as a safety measure relevant to risks regarding the loss of containment on gas pipelines, defined as: "Number of gas dig-ins per 1,000 Underground Service Alert tickets received for gas. The dig-in component tracks all dig-ins to PG&E gas subsurface installations. A gas dig-in refers to damage which occurs during excavation activities (impact or exposure) and results in a repair or replacement of an underground gas facility."[192] PG&E indicates that this metric is like the Gas Dig-In Rate used in the SPMs, except that the SPM metric counts only third-party gas dig-ins.[193]

Sempra Gas do not object to the inclusion of all gas dig-ins for this metric (first, second, and third party) if the metric is reported as set forth in General Order 112-F.[194] TURN had no comment but recommends[195] addition of Gas Loss of Containment and Shut-In Time as SOMs.

The SPM measurement units for Dig-Ins are the number of events per 1,000 Underground Service Alert Tickets received, but only including third-party events. The metric is typically used by utilities to gauge the effectiveness of public awareness campaigns and is reviewed during audits of the public awareness program. Staff agrees with PG&E's proposal to add all parties including the company itself and contractor dig-ins to provide a comprehensive total.

For SOM purposes, Staff recommends separate Gas Dig-In metrics for Transmission and Distribution systems. The consequences of a transmission loss of containment can be more severe than a distribution event. Staff recommends adopting the following metrics as SOMs suitable for use as Triggering Events for the purpose of PG&E's EOE process:

- *Number of Gas Dig-Ins per 1,000 Underground Service Alert tickets on Transmission pipelines*

[191] Code of Federal Regulations (CFR), Title 49, Part 192 Section 614.

[192] PG&E's ACR Response, at 11.

[193] D.19-04-020, (SPM #5), Approved Safety Performance Metrics (Version 1.0), Attachment 1.

[194] Sempra's March 1, 2021 Additional Comments, at 3.

[195] TURN March 1, 2021 Additional Comments, at 12.

- *Number of Gas Dig-Ins per 1,000 Underground Service Alert tickets on Distribution pipelines*

  Number of Gas Dig ins per 1,000 Underground Service Alert tickets is defined as: *the number of excavation damages per 1,000 Underground Service Alert tickets by first, second, or third party.*

Excavation damage is a leading cause of pipeline safety incidents. While utilities do not have complete control over third-party dig-in damage they can exert influence and are required to promote damage prevention by safety regulations.

These metrics have both leading and lagging properties. They are leading in the sense that dig-ins produce loss of containment; when more loss-of-containment incidents occur, the likelihood of a high-consequence event increases. They are lagging as an indication that public awareness and other damage prevention operations have become less effective.

8.1.2 Large Overpressure Events

Gas safety regulations specify the Maximum Allowable Operating Pressure (MAOP) for pipelines based on the strength of the pipe material and the population density in the potentially affected area. PG&E has defined "large" events as those exceeding the MAOP by certain amounts depending on the pipeline conditions. For example, a transmission OP event would be considered large if the pressure reached 10 percent or more above the MAOP. The measurement units are the number of large events per time.

This metric meets the selection criteria of *objective, measurable, reportable, and verifiable*. It is a leading metric for loss of containment. Overpressure does not usually result in loss of containment but the higher the number of overpressure events the more likely a leak or rupture will occur.

The metric was proposed by PG&E. PG&E defines the Large Overpressure Events metric as:

"Count of large overpressure events. The proposed pressure limits for large [Overpressure] OP events are:

- High pressure gas distribution:
  - (MAOP 1 psig to 12 psig) greater than 50 [percent] above MAOP
  - (MAOP 12 psig to 60 psig) greater than 6 psig
- Low pressure gas distribution: by 16 inches water-column
- Transmission pipelines: by 10 [percent] MAOP (or the pressure produces a hoop stress of ≥75 [percent] Specified Minimum Yield Strength [SMYS], whichever is lower)."[196]

[196] PG&E's ACR Response, at 12.

PG&E indicates that this metric is already reported to the Commission, and while there is currently no industry-wide metric against which PG&E's performance can be benchmarked, its value and importance support its inclusion as a SOM.[197]

There are minor differences in the way PG&E defines a "large" overpressure event and the definitions of GO112-F for reporting overpressure events. Staff recommends the Commission adopt a Large Overpressure Event metric but recommends adhering to the GO112-F definitions of an overpressure event for SOM reporting to maintain consistency.

Sempra have no objection to reporting overpressure events as specified in General Order 112-F Sections 122.2(a)(3) (per event), 122.d(5) (quarterly), and 123.2(d) (annually).[198] General Order 112-F requires annual reporting of overpressure events, but with different criteria than proposed by PG&E for this metric.

To avoid confusion and maintain consistency, Staff recommends the following definition from GO112-F 122.2(d)(5):

> *"Incidents where the failure of a pressure relieving and limiting stations, or any other unplanned event, results in pipeline system pressure exceeding its established Maximum Allowable Operating Pressure (MAOP) plus the allowable build up set forth in 49 CFR § 192.201."*[199]

Staff further recommends that to allow comparison with other IOUs, the number of overpressure events should be normalized to the total length of pipeline in the PG&E system. The PG&E system total is approximately 50,000 miles of transmission and distribution pipeline.

Staff recommends adopting the following metrics as SOMs suitable for use as Triggering Events for the purpose of PG&E's EOE process:

- *Number of Large Overpressure Events, where overpressure events are defined as those reportable under GO112-F 122.2(d)(5).*[200]
- *Number of Large Overpressure Events for each unit of 50,000 miles, (overpressure events as reportable under GO112-F 122.2(d)(5)).*

If the Commission decides to also require SoCalGas to report this SOM, Staff recommends that SoCalGas be required to normalize its reporting by the SoCalGas's total system miles of approximately 105,000 miles. For example, 20 events for SoCalGas would be normalized to 10 per every 50,000 miles to allow comparison with PG&E.

[197] PG&E's ACR Response, at 12.

[198] Sempra's March 1, 2021 Additional Comments, at 3.

[199] CFR Title 49 Part 192 Section 201.

[200] CFR Title 49 Part 192 Section 201.

Although the definition from General Order 112-F 122.2(d)(5) is specified for quarterly reporting, Staff recommends that PG&E report these SOMs on the same basis chosen for the other SOMs.

8.1.3 Gas Emergency Response Time

PG&E operates a call center to receive phone reports of suspected gas emergencies. The center dispatches a PG&E representative to the site for initial assessment of an unsafe condition. Prompt response to an emergency helps to start the remediation sooner, which is expected to reduce the consequences. The metric Gas Emergency Response Time also gives some insight into quality of service and management effectiveness of the response operations.

PG&E proposes the metric Gas Emergency Response Time as a safety measure relevant to risks regarding the loss of containment of gas pipelines, as well as a quality of service and management measure.

PG&E defines the *Gas Emergency Response Time* as: "*Measured from the time PG&E is notified to the time a Gas Service Representative (or a qualified first responder) arrives onsite to the emergency location (including Business Hours and After Hours).*"[201] PG&E indicates that the metric measures the average response time for immediate response orders for the performance period.

Sempra recommend to that this metric be reported as set forth in General Order 112-F.[202] Staff notes, however, that there are differences from the GO112-F definition and the PG&E proposal in the determination of response activity completion. In the General Order, the response is completed when the reported leak is confirmed as not hazardous, or the operator completes actions to mitigate a hazardous leak. In the PG&E proposal, the response is completed by the arrival of the responder on site. Staff recommends the Commission adopt the metric as proposed by PG&E without modification because Staff is proposing an additional metric to track Gas Shut-In Time separately.

8.1.4 Gas Shut-In Time

The consequences of a gas incident can be more severe the longer gas continues to flow. If the gas is feeding a fire it may burn longer. If the gas has not yet ignited, more serious consequences may be avoided with prompt closure of the line.

TURN proposes a *Gas Shut-In Time* metric, defined as "*the average time in minutes required for the utility to stop the flow of gas during incidents involving mains, or services, when responding to any unplanned or uncontrolled release of gas*."[203]

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[201] PG&E's ACR Response, at 12.

[202] Sempra's March 1, 2021 Additional Comments, at 3.

[203] TURN March 1, 2021 Additional Comments, at 12.

The timing for the metric starts when the utility first receives the report and ends when the utility's qualified representative determines, per the utility's emergency standards, that the reported leak is not hazardous, a leak does not exist, or the utility's representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (i.e., by shutting-off gas supply, eliminating subsurface leak migration, repair, etc.) per the utility's standards. The longer a gas leak can flow, the greater potential consequences.

Gas Shut-In Time is reported separately for mains and services as SPMs.[204] Similarly, Staff recommends adopting two separate metrics as SOMs suitable for use as Triggering Events for the purpose of PG&E's EOE process:

- *Gas Shut-In Time for Mains*
- *Gas Shut-In Time for Services*

8.1.5 Uncontrolled Release of Gas on Transmission Pipelines

The loss of containment, or uncontrolled release, of gas from a transmission pipeline can have serious consequences. A release may take the form of a leak, or a rupture. Routine operations are aimed at preventing uncontrolled releases and such events are rare for transmission pipelines. Measurement units are the number of uncontrolled release events per period of interest.

The metric *Uncontrolled Release of Gas on Transmission Pipelines* applies only to transmission pipelines, which normally have very few such release events. But those events can have serious consequences due to the large amount of energy present in transmission lines. An increasing number of events increases the likelihood that one of them becomes a serious incident, so this metric is a leading indicator of potential incidents but also a lagging indicator for failure to control the release of gas.

All leaks are not routinely reported. The number of gas pipeline leaks repaired are reported to the Commission under GO112-F but some minor leaks may remain open for up to three years and so are not reported until repaired. Leaks that are associated with reportable incidents are also reported to the Commission; reportable incidents meet specified criteria such as $50,000 loss, injury requiring hospitalization, media attention, etc.

This metric will capture all leaks on transmission lines whether routinely reported or not. Staff recommends adopting *Uncontrolled Release of Gas on Transmission Pipelines* as a SOM suitable for use as Triggering Events for the purpose of PG&E's EOE process, defined as: the number of leaks, ruptures, or other loss of containment on transmission lines for the reporting period.

[204] D.19-04-020, (SPM #8,9), Approved Safety Performance Metrics (Version 1.0), Attachment 1.

8.2 Reporting Requirements

Currently, utilities are required to report natural gas Safety Performance Metrics (SPMs) once a year on March 31st to the Commission, pursuant to D.19-04-020:[205] Staff recommends that PG&E reports the following gas related SOMs on an annual basis and that PG&E provide all historical annual data with its first SOM submission.

8.3 Discussion

Parties' Informal Comments on Draft Staff Proposal

Cal Advocates supports the Draft Staff proposal, with suggested modifications to the response time SOMs. Rather than report a single average response time, the metrics should capture the distribution of response times in a granular way. SOM 4.5 and 4.9. Staff agrees with Cal Advocates that the Response Time SOMs 4.5 and 4.9 (and 5.1) should be modified to require SOM reporting of response times in a granular way, particularly as defined in GO 112-F, Section 123.2 c), which includes the times to render the leak non-hazardous (by shut in or other means) and time to arrive on site reported in intervals:

> *"Response times in five-minute intervals, segregated first by business hours (0800 – 1700 hours), after business hours and weekends/legal state holidays, and then by Division, District, and/or Region, to reports of leaks or damages reported to the utility by its own employees or by the public. The intervals start with 0-5 minutes, all the way to 40-45 minutes, an interval of 45-60 minutes and then all response times greater than 60 minutes."*

The timing for the response starts when the utility first receives the report and ends when a utility's qualified representative determines, per the utility's emergency standards, that the reported leak is not hazardous or the utility's representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (i.e., by shutting-off gas supply, eliminating subsurface leak migration, repair, etc.) per the utility's standards. In addition, the utility must report, using the same intervals, the times for the first company responder to arrive on scene."

PCF supports the Staff proposal but suggests more emphasis for Safety Performance Metrics (SPMs) on gas operations and "clean energy metrics". PCF recommends modification of SPMs 27, 28, 29, and 31 to apply to gas as well as electric operations. They also propose several metrics, without specifying as SPMs or SOMs, to measure methane emissions because of GHG emissions concerns.

[205] D.19-08-020, *Second Phase Decision Approving Natural Gas Leak Abatement Program Consistent with SB 1371 and SB 1383,* August 15, 2019, Ordering Paragraph 2.

Safety Policy Division Staff are responsible for administration of the Natural Gas Leak Abatement Program (NGLA), as ordered in D.17-06-015[206] (cited by PCF in their comments). The NGLA Program requires regular reporting of natural gas leak data. The number, types, emission volumes, and sources of leaks is described in detail in those reports. The Program also requires biennial filings of Compliance Plans, to demonstrate how the utility will implement the twenty-six Best Practices for emissions reduction listed in the Decision, to achieve the Statewide GHG emissions reduction goal of forty percent by 2030. Further, the Second Phase NGLA Decision introduced a financial incentive to achieve an interim twenty percent reduction by 2025.[207]

Utility Consumer's Action Network (UCAN) mode no comments on the proposed gas SOMs but offered three "simple" metrics concerning the role of natural gas in climate change: Total GHG contribution from its customer footprint; Total gas losses determined as the difference from gas input to gas sold; and Total methane losses to the environment as a percentage of total gas losses.

Staff appreciates the concern about the role of natural gas in global warming. The State already has programs in place to regulate GHG emissions from natural gas combustion (Cap and Trade) and methane emissions from natural gas pipeline facilities (the Natural Gas Leak Abatement Program of the CPUC).

Staff does not agree that the proposed metrics are simple. Staff knows from experience that the subtraction of gas input minus gas sold, sometimes referred to as LUAF (Lost or Unaccounted For gas), is not an accurate representation of gas lost to the environment. Subtraction results include theft or other unbilled gas usage and inaccuracies in measurement, and so do not provide a reliable measurement of emissions. Methane leak volumes in cubic feet are the subject of intensive annual emission inventory reports co-written by the Safety Policy Division and the Air Resources Board (ARB). These reports show that the contribution to Statewide GHG by gas pipeline leaks is a very small component of methane emissions overall. The comprehensive GHG survey produced by ARB shows that total methane emissions are dominated by agricultural methane emissions, which in turn are a small part of total GHGs. Staff does not agree that further metrics are warranted.

Staff notes the interest in the GHG emissions impacts related to the delivery and operation natural gas systems by some parties. Staff respectfully suggests the parties review the existing program materials and reports such as the annual Methane Emissions Inventory co-produced by the Safety Policy Division and the Air Resources Board for comprehensive metrics on natural gas leaks from utility facilities, Available here: https://www.cpuc.ca.gov/General.aspx?id=8829

[206] D.17-06-015, *Decision Approving Natural Gas Leak Abatement Program Consistent with SB 1371,* June 15. 2017.

[207] D.19-08-020.

PG&E made the following suggestions for modifying Staff's recommended SOMs:

- SOM 4.1 and 4.2, *Pipeline Dig-Ins*: PG&E states they cannot separate dig-in information by transmission vs. distribution pipelines and recommends that the total of both is reported as one metric as they originally proposed. Staff agrees with the PG&E recommendation, SOM 4.1 should be modified to include transmission and distribution pipelines, and then 4.2 can be removed.
- SOM 4.4, *Normalized Overpressure Events*: PG&E supports this metric but suggests that the number of events should be normalized by the number of SCADA pressure transducer reading points instead of by pipeline miles. Staff agrees that the number of pipeline pressure transducer points is an appropriate figure for normalizing overpressure events. The detection of overpressure conditions is performed by the transducer devices installed along the length of a pipeline. If there are more transducers, there will be more opportunities for an overpressure to be found; and the total number of transducers will be roughly proportional to system size. Staff accepts the PG&E proposed modification.
- SOM 4.5, *Gas Emergency Response Time*: PG&E states that SOM 4.5 is the same as 4.9, so they should be condensed to one SOM. Staff agrees that as presented in the Staff Proposal these two are erroneously the same, and recommends the issue be resolved with the solution offered in the response to the Cal Advocates comments which differentiates time to arrive on site, and time to render the situation non-hazardous.
- SOM 4.6, *Gas Shut-In Time, Mains*: PG&E supports this metric but recommends median, rather than average, time. Staff notes that use of the response time metrics defined in GO 112-F, as recommended in the Cal Advocates discussion, would include shut-in time in a more granular fashion and so dismiss the question of median vs average.
- SOM 4.7, *Gas Shut-In Time, Services*: PG&E also recommends use of median, rather than average, time. As previously noted in 1.1.1 above, adoption of the GO 112-F response time metrics would include shut-in time in a more granular fashion.

PG&E also suggested modifications to SPMs 13 and 44, which are discussed in the SPM section (Part II of this document).

8.4 Staff Recommendations on Natural Gas System Related SOMs

Based on parties' informal comments on the Draft Staff Proposal, Staff has modified the following natural gas system related SOMs:

Staff Proposed SOM Name	Definition
Number of Gas Dig-Ins per 1000 USA tickets on Transmission and Distribution pipelines	Number of Excavation Damages per 1000 Underground Service Alert (USA) tickets by any party on all pipelines.
Number of Overpressure Events	Overpressure events as reportable under GO112-F 122.2 (d)(5).
Normalized Overpressure Events	Number of OP Events normalized by the number of pressure transducers on the system
Time to Respond on Site to Emergency Notification	Reported in increments per GO 112-F 123.2 (c), time to arrive on site.
Time to Resolve Hazardous Condition	Reported in increments per GO 112-F 123.2 (c), time to confirm non-hazardous condition.
Gas Shut-In Time, Mains	Reported in increments per GO 112-F 123.2 (c), time to shut-in gas when gas release occurs on a main.
Gas Shut-In Time, Services	Reported in increments per GO 112-F 123.2 (c), time to shut-in gas when gas release occurs on a service.

9 Quality of Service, Quality of Management & Affordability

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 addressing Safety and Operational Metrics described above.[208]" Accordingly, the Assigned Commissioner's Ruling issued on November 17, 2020 states 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. PG&E should include metrics on customer engagement, satisfaction, and welfare in its proposed quality of service and management metrics."[209] Additionally, as noted previously, D.20-05-053 articulates that SOMs should be a means to "ensure that PG&E provides safe, reliable and affordable service consistent with California's clean energy goals."[210]

9.1 Quality of Service

For a Quality of Service SOM, Staff only recommends one metric – *Average Speed to Answer for Emergencies.* Several other metrics, which are fundamental to quality of service such as reliability and emergency response time are included in prior metrics. This section also discusses other alternatives that Staff considered, and Staff requests that parties propose additional quality of service metrics if they feel they would be beneficial.

PG&E proposal on this is as follows:[211]

"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 (ASA) in seconds for Emergency calls handled in Contact Center Operations.

This metric is a leading indicator, outcome-based, benchmarkable, and relies on objective data."

Staff agrees with PG&E that Average Speed of Answer is a good metric for the reasons PG&E articulates.

SCE comments that "this metric should include defining precisely what 'emergency' means in this context. Absent a common definition, it will be very difficult for the IOUs to provide reasonably consistent and comparable metric data that will be useful to the

[208] D.20-05-053 at 90.

[209] Assigned Commissioner's Ruling Regarding Development of Safety and Operational Metrics, November 17, 2021.

[210] D. 20-05-053 at 38.

[211] PG&E's ACR Response.

Commission."[212] SCE makes a valid point regarding this metric and Staff agrees that a clear definition in the context of this metric is important. In this case, the context is quality of service and, as PG&E uses this metric in their Short-Term Incentive Program (STIP), the metric is intended "to promote prompt handling of emergency calls from customers."[213]

When a customer calls PG&E, the customer is prompted to denote whether the call relates to an emergency. If the customer denotes an emergency, the call is transferred into a queue, at which time a speed-of-answer measurement begins and then ends when the call is answered by a representative. This metric measures the average speed of answer in seconds for emergency calls, thereby promoting expeditious handling of such calls.[214] In this context, this metric would be measuring PG&E's customer service at a critical time – when the customer believes they are experiencing an emergency. For this reason, it is a useful measure of quality of service.

As noted above, TURN accurately points out that "[i]t is important to know that the utility is answering calls in a timely matter, but the [Average Speed of Answer] ASA provides only limited insight on safety. The metric tracks the [Average Speed of Answer] ASA instead of the time from the receipt of the call to the resolution of the potential emergency. The utility could have an effective and efficient call center, but it does not necessarily follow that the resolution of the safety concern at issue in the call will be quickly and efficiently addressed." TURN's observation is entirely correct, but as noted elsewhere in this proposal, SOMs, at the direction of the Commission, should also include metrics on customer engagement and satisfaction.

Other Quality of Service Metrics for Consideration by Parties

Aside from the Average Speed of Answer metric, PG&E did not recommend metrics that directly measure quality of service, but instead argues that their proposed SOMs "provide a representative, objective assessment of PG&E's service and management priorities. As an initial matter, metrics that capture key safety and reliability risks go to the very heart of service and management priorities; taken as a whole, the SOMs appropriately address those issues.[215]" PG&E goes on to point out that their proposal includes electric and gas emergency response time as well as SAIDI (Unplanned). Staff agrees that emergency response time and measurements of reliability are important elements of quality of service and have included them in prior sections. However, in addition to the other SOMs that cover reliability and safety, staff believes other quality of service metrics would be beneficial in promoting improved operations via the EOE process.

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[212]SCE's Opening Comments on Assigned Commissioner's Ruling (SOMs), January 25, 2021,, at 8.

[213] SCE's Opening Comments on Assigned Commissioner's Ruling (SOMs), January 25, 2021, at 8.

[214] Executive Compensation Approval Request to Wildfire Safety Division, January 15, 2021.f

[215] PG&E's ACR Response at 10.

As discussed in the April 22nd Draft Proposal circulated to parties, Staff evaluated other possibilities that were ultimately rejected here. Staff recommends that further research and discussions both within the Commission and with parties should take place before an additional quality of server operational metric is adopted.

Measuring quality of service will be useful to the Commission in better understanding the customer experience in ways beyond affordability, reliability, safety, and in fielding customer complaints. On the other hand, the reliability and safety SOMs proposed here may be very highly correlated with customer satisfaction obviated the need for a specific customer satisfaction metrics. In any case, at this time, Staff does not have a specific recommendation beyond Average Speed to of Answer.

9.2 Quality of Management

As noted above, 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 addressing safety and operational metrics. At this time, Staff does not recommend an additional SOM on Quality of Management. As noted above, PG&E did not propose any quality of service or quality of management metrics. Likewise, no parties indicated a need for "quality of management" metrics in their comments on PG&E's SOMs proposal. Staff invites parties to propose potential "quality of management" metrics in comments.

Staff believes that EOE process evaluation of PG&E Quality of Management is important. Fortunately, step 1 of the EOE Process already directly addresses this. If PG&E fails to show "sufficient progress on any metric…resulting from its on-going safety culture assessment"[216] they can be placed into step 1 of the EOE process. The "ongoing safety culture assessment" refers to the PG&E Safety Culture Investigation (I.15-08-019) and the recommendations required under D.18-11-050, *Decision Ordering PG&E to Implement the Recommendations of the NorthStar Report.* These recommendations include several measurable quality of management recommendations.

Examples of the over 60 recommendations that PG&E is required to implement as part of the Safety Culture Assessment include requiring implementation of regular pipeline operator qualification status reports, a requirement to increase the number of supervisors in field operations for all lines of business to limit the span of direct reports to a maximum of 1:20, a requirement to transfer administrative tasks such as scheduling of work, training and paperwork review from supervisors to the office-based staff, reducing travel requirements for field personnel and supervisors, an annual (or biennial) blue sky strategic safety planning exercise to concentrate on the changing environment, potential risks and threats," and

[216] D.20-05-053, Appendix A, at 2.

several other mandatory changes to how PG&E manages their operations in order to improve safety and safety culture.[217]

The Safety Culture and Governance Section within the Commission's Safety Policy Division reviews quarterly reports from PG&E and regularly consults with North Star to ensure progress is being made on these recommendations. The next quarterly report will be submitted before the end of April.

9.3 Affordability

Californians' energy costs and rates are rising and disproportionately impact affordability for low-to-moderate-income residents. The Commission is increasingly concerned that bundled residential rates in the State are higher than the median in national rankings. There are several causes for these rapid rate increases, including the acceleration of transmission and distribution rate base in recent years, and rate impacts are exacerbated by substantial wildfire mitigation plan costs and higher than national average returns on equity. Additionally, Net Energy Metering and Distributed Energy Resources customers are disproportionately wealthier homeowners that can reduce bill impacts by investing in solar, storage technologies, electric vehicles, and other behind-the-meter solutions. The current NEM tariff has allowed wealthier customers to avoid paying for much of the fixed costs of grid maintenance and modernization, which is then shouldered by other customers, thus contributing to affordability and equity concerns. Another contributor is the slightly higher than national average return on equity for California IOUs.[218]

Despite these concerns, Staff does not formally recommend an affordability metric in this proposal but does request further input on this topic from the TWG and in party comments. Basing enforcement on the affordability of rates is problematic on several levels. Foremost is the fact that rates are approved by the Commission. The Commission has direct responsibility for oversight and approval of rates. Subjecting PG&E to the Enhanced Oversight and Enforcement process based on the affordability of rates that were approved by the Commission would be questionable from a policy perspective.

TURN proposes[219] the inclusion of affordability metrics in the SOMs. These include the metrics adopted in D.20-07-032 as part of rulemaking R.18-07-006, which addresses affordability across multiple utility sectors. As ensuring affordable utility services is a core function of the Commission, Safety Policy Division Staff carefully considered TURN's suggestion and consulted with Energy Division staff who worked on this proceeding. The metrics adopted in D.20-07-032 are valuable for the purpose of tracking and understanding

[217] Assessment of Pacific Gas and Electric Corporation and Pacific Gas and Electric Company's Safety Culture: First Update/Final Report. Prepared NorthStar Consulting Group for CPUC March 29, 2019.

[218] CPUC En Banc on Rates and Costs

[219] TURN March 1, 2021 Additional Comments, at 13.

utility affordability throughout the state, but Staff does not agree they would be useful for enforcement purposes. Further explanation of the reasoning for rejection of these proposed metrics is laid out in the April 22nd Draft Staff Proposal circulated to the TWG and TURN did not object to their exclusion in their May 11th informal comments. Staff's April 22nd Draft proposal also considered the use of "Greater Affordability for Customers" metric used as a factor in calculating PG&E's Long-Term Incentive Program. In their Executive Compensation Approval Request, but determined it would not be suitable for use as a SOM.[220]

[220] Pacific Gas and Electric Company's Executive Compensation Approval Request Pursuant to Public Utilities Code § 8389(e)(4) and (e)(6).

10 Clean Energy Goals

The SOMs are intended to "ensure that PG&E provides safe, reliable, and affordable service consistent with California's clean energy goals."[221] The PCF observed that "despite the express direction provided by the Commission in D.20-05-053 and by the Assigned Commissioner's Ruling in this proceeding, PG&E's proposed SOMs fail to provide metrics that would enable the Commission to ensure the utilities are meeting California's clean energy goals. PCF recommends that the Commission adopt metrics to enable the Commission to assess whether the utilities can more quickly reduce their GHG emissions, as required to avoid the most catastrophic change impacts."[222]

Pursuant to the California Global Warming Solution Act of 2006, Assembly Bill (AB) 32, California is implementing numerous programs to achieve the 2030 and 2050 state's GHG emissions reduction goals of 40 percent and 80 percent, emissions reductions below 1990 levels, respectively. This program mandates a firm economy-wide cap on various GHG emissions sources in California, including the industrial sector, and generators and deliverers of electric and gas energy. Other policies continue to advance clean energy and reduction in emissions, including, amongst others, energy efficiency, energy storage, low carbon fuels, and zero-emission vehicles.

The state established aggressive mandatory clean energy procurement targets through the Renewable Portfolio Standard (RPS) established in 2002. In 2018, the legislature increased RPS targets to 60 percent by 2030 and established a goal for 100 percent of the State's electricity to come from renewable and carbon-free resources by 2045. Under the current proceeding, the Commission oversees the regulated utilities' activities towards meeting the state's RPS goals.[223]

In addition, the Clean Energy and Pollution Reduction Act (Senate Bill 350) established 2030 targets for energy efficiency and renewable electricity, amongst other activities, to reduce the use of fossil fuel energy and GHG emissions. Accordingly, in coordination with the California Air Resource Board (CARB) and the California Energy Commission, the Commission initiated the Integrated Resource Planning proceeding (R.20-05-003),[224] requiring utilities to set 2030 GHG emissions targets for the electricity sector, while maintaining system reliability need in each year based on the CEC's demand forecasts.[225]

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[221] D.20-05-053, at 38.

[222] PCF Comments on PG&E Workshop, at 2.

[223] Order Instituting Rulemaking To Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program (R.18-07-003).

[224] Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements (R.20-05-003).

[225] SB 350 Integrate Resource Planning 2020 Update.

In their IRP plans, utilities must show how they are going to meet their customers' demand, while achieving the emissions targets in a cost-effective manner. As part of each IRP cycle, the Commission adopts a GHG planning target for the electric sector and identifies a portfolio with the optimal mix of resources needed to meet state policy goals.[226]

The Commission has set rigorous procurement policies in place prior to approving funding for utilities' programs (including clean energy, energy efficiency and GHG reduction programs), and approving the revenue requirement associated with the procurement and delivery of electric and gas energy required to fulfil utilities' obligations to serve and meet the need of their customers, through the Energy Resource Recovery Account (ERRA) mechanism.

Prior to approving IOUs' revenue requirements (recovered in rates), the Commission requires utilities to submit annual ERRA procurement applications forecasting their revenue requirements and detailing in their programs implementation plans how they will comply with the State's policies, while addressing safety, reliability, just cost, clean energy, and emissions reduction goals.[227] Utilities are then required to file ERRA compliance applications indicating their actual compared to forecasted costs, program outcomes, and their compliance with the Commission's and state's regulations and goals, including but not limited to, from energy efficiency and demand response programs, GHG emissions reductions and other air pollutants, solar and renewable energy, amongst other compliance requirements.

In addition, to the ERRA mechanism, the Commission established reporting requirements to ensure that the Commission and stakeholders are able to rigorously evaluate utilities' applications to determine if utilities are implementing their programs prudently, in compliance with state's and commissions laws and regulations, and their estimated GHG emissions and costs are reasonable. Pursuant to D.14-10-033, which implements a part of the GHG reduction program envisioned by AB 32 to further improvements in the health and safety of California residents, utilities are required to use specific methodologies consistent with CARB regulations, to calculate their forecasted and recorded (actuals) GHG emissions and compliance costs that are associated with electric procurement to meet customers' energy demand. Similarly, the Commission established standard procedures and rules

[226] 2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning, D.20-03-028. See Fact Sheet on D.20-03-028.

[227] Pursuant to D.02-10-062, the Commission requires the regulated electric and gas utilities to track fuel and purchased power billed revenues against actual recorded costs of these items, established the ERRA balancing account mechanism. In the annual ERRA forecast application, a utility requests adoption of the utility's forecast of its expected annual fuel and purchased power costs for the upcoming 12 months. Approval of the forecast allows utilities to recover their ERRA revenue requirement in rates. The Commission is required to perform a compliance review of the ERRA balancing account and related regulatory accounts and certain non-ERRA accounts. A compliance review considers whether a utility complied with all applicable rules, regulations, opinions and laws.

necessary for natural gas investor-owned utilities to comply with the California Air Resources Board's Cap-and-Trade Program.

In addition to the energy efficiency and customer distributed energy programs, the Commission adopts new clean energy and energy efficiency projects funded with Cap-and-Trade Program funds, including the Solar on Multifamily Affordable Housing (SOMAH) program, and buildings' decarbonization. Another relevant Commission proceeding is R.13-02-008, which adopts standard and requirements relative to health, safety, and integrity for biomethane injected into common carrier pipelines.

10.1 Discussion

In the initial Draft Staff Proposal, which was circulated to the TWG on April 22, 2021 for informal written comments, Staff did not recommend specific Clean Energy Goals SOMs, but sought further suggestions and discussion with the TWG on this topic. Staff invited suggestions around a discrete set of key energy targets, such as those set out in specific statutory provisions and/or particular Commission proceedings, such as the RPS (R.18-07-003) or IRP (R.20-05-003).

In their Informal Comments on the Draft Staff Proposal, PCF recommends some clean energy related metrics related to measurement of emissions associated with leaks, social costs associated with methane emissions from all operations, including mitigation measures, honmes retrofitted to operate independently from the grid in HFTD for durations of PSPS events, percentage of projected underway utilizing zero carbon-emitting resources. PCF also recommends that the Commission prepare a GHG emissions reduction plan under the California Environmental Quality Act (CEQA) to ensure GHG emissions reductions and climate change impacts are considered in all of the Commission's decisions, including both gas-related and electric-related decisions.

UCAN made similar recommendations and advocates for the inclusion of the following three safety related metrics in the context of global warming, from all large gas-supply-to-customer utilities: (1) utilities should report total utility GHG emissions caused from its customer footprint. A hypothetical gas burn-rate may be needed to translate natural gas supplied to specific GHG impacts from total utility gas sales; (2) a metric is needed based on the total estimated utility gas losses as a result of its customer footprint, defined in therm or BTU terms. The total gas input into the utility system would be compared to the total gas output sold to customers to determine this net residual amount of gas losses; (3) for each utility, based on its entire customer footprint, that total methane losses to the environment be estimated as a percentage of total utility gas losses. UCAN states that the "reason is simply that methane is an extremely potent global greenhouse gas which should be a focus point, monitored and minimized. The impacts of GHG emissions are direct, the results from natural gas burn and natural gas losses, as well as methane emissions." UCAN also claims that "these three simple metrics are not directly reported by utilities to date but should be in this utility/customer risk-based proceeding" as the risks of gas use and methane appear more evident by the day. In fact, the Commission requires utilities to track, measure and report these specific metrics, (refer to the NGLA and Cap-and-Trade proceedings discussed above).

In this report, Staff has discussed that PG&E's SOMs will be considered as "indicator light" to evaluate if PG&E's is making insufficient progress in its safety and operational performance. Staff has described that it will pursue qualitative and quantitative assessment of PG&E's performance as reflected reported data in lieu of setting specific targets at this time. It is technically infeasible to attribute GHG emissions to a single originating source in order to assess PG&E's safety and operational performance. As discussed, the requirements of energy procurement policies to maintain system reliability cost-effectively add another layer of technical complexity in determining PG&E's specific future emissions targets.

As such, Staff declines to adopt PCF and UCAN's suggested metrics as Triggering Events SOMs. Per Commission directives, the purpose of the EOE process is to allow the Commission to take additional steps to ensure PG&E is improving its safety and operational performance if Triggering Events occur. Under this framework, PCF and UCAN's suggested metrics do not fit the purpose of the EOE under Step 1 of the EOE process.

However, in the context of safety performance metrics associated with GHG emissions reduction, it is possible to estimate GHG emissions resulting from wildfires or large ignitions associated with gas explosions, which could be considered as a researchable topic in Phase II of this proceeding.[228]

10.2 Staff Recommendations on Clean Energy Goals SOMs

Staff recommends that PG&E report on any Commission established clean energy targets that it has failed to meet during the reporting period, as a SOM for the purpose the EOE process.

In addition, within the context of the RDF proceeding, Staff has proposed in the Staff Proposal on RDF clarifications that the Commission consider refining the RDF adopted in D.18-12-014 to develop a framework for assessing risks and identifying mitigation measures associated with climate change impacts on utility electric and natural gas infrastructure and operation, as well as customer impacts in a later phase of this proceeding.

[228] Refer to Appendix A for further discussion on Staff recommendations on the treatment Climate Change Impacts in RDF.

Part II

11 Modifications to Adopted Safety and Performance Metrics

The Scoping Memo includes the following issues related to modifications of adopted SPMs:

- Issue (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?
- Issue (e) Should the Commission develop a method to streamline safety performance metrics development and reporting across proceedings? If so, what methods should be considered?

On issue (e), Staff believes Commission staff should work to better collaborate and coordinate across Divisions on the development, organization, storage, and use of data it collects. Analysis and enforcement could be streamlined if data were stored in an accessible repository for use by the public, parties, and the Commission. In reviewing the SPMs, Staff has looked closely at data collected by other Divisions and, where possible, seeks to align definitions and requirements with other Divisions within the Commission, to avoid partially overlapping, but essentially redundant data collection. This streamlining effort would not require a directive from a decision, but rather continued, focused, collaborative effort by Staff.

On issue (d), Staff recommends both the revision and expansion of Safety Performance Metrics.

Staff proposes additions and modifications to the 26 SPMs adopted in D.19-04-020. The additional SPMs listed below were among dozens proposed by members of the Technical Working Group convened following D.19-04-020 and proposed here for further evaluation and refinement.

As the SPMs are applicable to all IOUs (rather than just PG&E), these metrics overlap with SOMs. They provide both a useful oversight tool and can be used to spur investigations and inform enforcement actions.

11.1 Background

In D.19-04-020, the Commission indicated that SPMs provide both a useful oversight tool and can be used to spur investigations and inform enforcement actions.[229] Ordering Paragraph 4 of D.19-04-020 also authorized Safety Enforcement Division (SED) staff to reconvene the S-MAP Technical Working Group to develop an updated electric overhead conductor index (EOCI) and additional safety performance metrics as feasible.[230] Ordering Paragraph 5 directed the three large electric utilities (PG&E, SCE, and SDG&E) to provide an updated proposal of electric overhead safety index.[231] The initial EOCI was proposed by SED and included:

1. Circuit miles of electric distribution infrared inspections completed,
2. Circuit miles of distribution electric conductor upgraded/replaced, and
3. Number of trees trimmed/removed as part of the vegetation management program.

As D.19-04-020 indicated, TURN and the three electric utilities were opposed to adopting the SED-proposed EOCI and the component metrics that made up the EOCI. Besides SED, the former Office of Safety Advocates was the only other entity that favored adopting the SED-proposed EOCI. In light of parties' respective positions, the Commission directed SED staff to reconvene the S-MAP Technical Working Group to develop an updated electric overhead safety index and any additional safety performance metrics as feasible.

Following the D.19-04-02 decision, SED staff reconvened the S-MAP TWG and on June 30, 2019, the three large electric IOUs submitted alternative electric overhead conductor metrics to the TWG. The three IOUs reiterated their opposition to using an index to gauge the safety performance of electric overhead conductors and proposed several safety metrics. These proposed EOCI metrics could be considered as either standalone safety metrics or as component metrics to be used in an updated EOCI.

PG&E Proposal

PG&E proposed the following leading indicator metrics as the Electric Overhead Conductor Index:

Miles of System Hardened, defined as miles of circuits with potential fire risk components within HFTD areas, having wildfire risk mitigated through either (1) rebuilding of overhead circuitry to current design standards; (2) targeted undergrounding; or (3) elimination of overhead circuitry.

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[229] D.19-04-020 at 33.

[230] D.19-04-020 at 33.

[231] D.19-04-020 at 33.

Miles of Enhanced Vegetation Management (EVM) Work Completed, defined as completed distribution circuit miles of vegetation cleared under the EVM Program scope within high-fire risk areas to reduce wildfire risk through (1) overhang clearing 4 feet vertical from conductor and (2) high-risk species mitigation.

SCE Proposal

SCE proposed adding the following metric to the set of approved safety performance metrics: Percentage of Small Conductor on the Overhead Distribution System. This metric is defined as the total length of distribution primary conductor that is smaller than 1/0 ACSR or #2 Copper divided by the total length of distribution primary conductor of all sizes. Conductor lengths will be measured in circuit miles for primary conductor (i.e., >600V).

SDG&E Proposal

SDG&E proposed adding the following metric to the set of approved safety performance metrics: Percentage of Small Conductor on the Overhead Distribution System. This metric is defined as the total length of distribution primary conductor that is size #4 and smaller divided by the total length of distribution primary conductor of all sizes. Conductor lengths will be measured in circuit miles for primary conductor (i.e. >600V).

Subsequent to the utilities' proposals, the S-MAP TWG met over several meetings to discuss the proposed electric overhead safety metrics. Alternatives to these proposals were also introduced by various intervenor parties and were also discussed. Besides considering electric overhead safety metrics proposed by the three electric utilities, the TWG also considered additions to the original 26 safety performance metrics that were adopted in D.19-04-020. Over 40 additional electric overhead metrics were introduced by various members of the TWG. Parties then submitted informal comments and reply comments to the TWG to discuss the original proposals and alternative proposals.

Generally speaking, there was little consensus between the utilities on one side and the intervenor groups on the other side. Of the over 40 proposed metrics, there was only one metric (the wire down percentages by cause metric) that received a somewhat high-level consensus, but even this metric received dissenting votes from PG&E and SDG&E. There were six proposed metrics that received partial consensus of at least one vote each from the utilities and the intervenors. The remaining proposed metrics received no overlapping votes between utilities and the intervenor groups.

Staff viewed the composite index as a problematic approach to assess the safety performance of a utility. A single deficiency in one critical metric can cause a catastrophic event. An index that is made up of component safety metrics can mask deficiencies and fail to accurately reflect safety performance because an index calculated as an average of multiple composite metrics can easily mask the deficiency in critical areas. For this reason, Staff recommends against using an index approach to gauge safety.

The following recommendations considered the initial list of over 40 proposed additional safety metrics and narrowed them down in light of the discussions held with the TWG. To accomplish this, Staff considered parties' explanations for their proposed metrics as well as the TWG's guiding principles for safety performance metrics.[232] Staff selected 17 of the metrics proposed by the D.19-40-020 Technical Working Group for further consideration in this proceeding. The proposed additional safety performance metrics, along with modifications to several currently adopted 26 metrics, are included in the Table 3, below.

Staff also recommends that parties consider updating terminology and definitions in the existing SPMs and Staff's selection of the S-MAP Technical Working Group's proposed SPMs, to align with the definitions of the Staff's proposed SOMs, where applicable. This will enable systematic assessment and evaluation of a utilities' safety performance.

Updates to the definitions of the adopted SPMs will provide consistency in definitions of performance metrics reported under the various Commission's proceedings. This approach allows for comparison across utilities, drawing from lessons learnt and best practices amongst utilities, which can result in improvement in the performance of utilities' operations and maintenance of its assets.

Refer to Appendix D for recommended modifications and additions to the adopted SPMs.

11.2 Discussion

On April 21, 2021, Staff circulated the Draft Staff Proposal including suggested additions and modifications to the 26 adopted SPMs in D.19-04-02. On May 11, 2021, parties provided their informal comments on the Draft Staff Proposal. Staff has modified some of the SPMs initially recommended in the Draft Staff Proposal.

Cal Advocates suggests that SPM definitions should match the SOM definitions for the same metric.[233] Staff agrees the SOMs and SPMs descriptions should match for the same metric. Cal Advocates also suggested an entirely new SPMs which did not appear in the Staff Proposal: Amount of Methane Lost Due to Leaks. Staff recommends that consideration of new SPM proposals, including methane metrics, should be deferred to Phase II. Methane emission measurements are already reported on, as discussed in Section 2.6.5.

UCAN suggested GHG emissions related metrics. Staff recommends that consideration of new SPM topics, such as methane metrics, should be deferred to Phase II. [234] Methane

[232] See: S-MAP Metrics Technical Working Group Guiding Principles - August 14, 2017 available here: https://www.cpuc.ca.gov/General.aspx?id=9099

[233] Cal Advocates TWG Track 2 informal comments on Draft Staff Proposal, May 11, 2021.

[234] UCAN TWG Track 2 informal comments on Draft Staff Proposal, May 11, 2021.

emission measurements are already extensively reported under the Commission's Natural Gas Leak Abatement Program, as discussed in response to comments in Section 2.6.5.

PCF recommends modifications to the Staff Proposal to include gas operations in some of the metrics:[235]

- SPM 27 and 28, "Median Time to Correct Inspection Findings", should be modified to include gas pipeline operations.
- SPM 29, "CPUC-Reportable Overhead Conductor Failure Incidents Excluding Media Attention," should be broadened to include any reportable incidents, such as on a gas pipeline, excluding media attention.
- SPM 31, "Wires Down Root Cause Analysis" should be modified to include gas incidents, such as gas leaks, because of global warming.

Staff does not agree with the PCF-proposed modifications. These SPMs were developed to address specific wildfire risk elements unique to electrical systems. Inclusion of gas information will dilute the usefulness of these metrics as tools for wildfire risk management. The most recent RAMP filings report that the magnitude of wildfire risk is far greater than gas system risk, so it is reasonable to overweight the metrics in favor of electric systems.

PG&E recommends the elimination of certain gas operations SPMs (SPMs #5, 8, 9,11, and 43) if the same metrics are adopted as SOMs.[236] Staff disagrees. SPMs which duplicate Staff's proposed SOMs should be retained for consistency. PG&E and Sempra suggest modifications to the definitions of Staff proposed SPMs, which Staff incorporated in its revisions, as summarized in Table x.[237]

As discussed in Part I, Staff modified the definition of Wires-Down SOMs to address gaps in the IOUs proposed definitions in response to the Draft Staff Proposal. Likewise, Staff modified the Wires-Down SPMs to address these gaps.

Refer to Appendix D for recommended modifications and additions to the adopted SPMs.

[235] PCF's TWG Track 2 informal comments on Draft Staff Proposal, May 11, 2021.

[236] PG&E's TWG Track 2 informal comments on Draft Staff Proposal, May 11, 2021.

[237] Sempra TWG Track 2 informal comments on Draft Staff Proposal, May 11, 2021.

Table 3: Revisions to Staff Recommended SPMs based on Parties' Informal Comments

SPM #	Metric Name (Adopted in D.19-04-020)	Description of Revisions
Revisions to SPMs Adopted in D.19-04-020		
1	Transmission & Distribution (T&D) Overhead Wires Down Non-Major Event Days	New definition for wires down
2	Transmission & Distribution (T&D) Overhead Wires Down - Major Event Days	New definition for wires down
5	Gas Dig-in	Description changed to match SOM 4.1. Staff clarified that the SPM measures dig-ins by any party.
6	Gas In-Line Inspection	PG&E suggests replacement with the count of missed compliance dates, due to variable intervals. Staff agrees and clarifies in-line inspection percentage metric.
7	Gas In-Line Inspection Upgrade	Staff clarified this number of inspectable miles metric.
8	Shut In The Gas Time-Mains	Cal Advocates recommends use of time increments for reporting response times instead of one average (or median time as Sempra recommends). Staff modified SPM to match the increment reporting requirements of GO 112-F.
9	Shut In The Gas Time-Services	Cal Advocates recommend use of time increments for reporting response times instead of one average (or median time as other parties commented). Staff modified SPM to match the increment reporting requirements of GO 112-F.
10	Cross-Bore Intrusions	Staff clarifies that the number of cross-bore intrusions per 1000 inspections should be reported annually.
11	Gas Emergency Response	Cal Advocates recommend use of time increments for reporting response times instead of one average (or median time as other parties commented). Staff modified SPM to match the increment reporting requirements of GO 112-F.
12	Natural Gas Storage Baseline Assessments Performed	PG&E indicates that there are no targets for storage well assessments yet established by CalGEM. Staff modified SPM to measure #assessments/planned assessments until targets are established.

SPM #	Metric Name (Adopted in D.19-04-020)	Description of Revisions
13	Gas System Internal Inspection Status	PG&E commented there is no requirement for a consistent program of upgrades for inline inspection (“pigging”). Staff modified SPM to measure total miles inspected and percentage of system that is “piggable.”
Revisions on the Additional SPMs (Not Currently Adopted in a decision)		
27	Median Time to Correct Inspection Findings, by Tiers or Grades	PCF pointed out that the descriptions for SPMs #27 and #28 appear to apply only to electric safety, but the proposed metrics were intended for both electric, gas, and dam safety. Sempra and PG&E request clarifications on the definitions of SPMs #27 and #28, as the requirement for calculation of median time is unclear given the tiers and grades have their own permitted time ranges. Staff clarifies that median time is calculated within each tier or grade; changed the definition to reflect that this metric applies to electric safety, gas safety, and dam safety inspection findings.
28	Median Time to Correct Inspection Findings, no Segregation by Tiers or Grades	Same changes as in SPM #27
29	CPUC-Reportable Overhead Conductor Failure Incidents	Removed dam and generation from SPM and added gas safety to metric.
30	Electric Overhead, wildfire	Reworded the definition of the SPM to refer to de-energization of downed conductors by automatic circuit protection devices, including fuses, circuit breakers, or reclosers.
32	Wires Down by Cause	Deleted mention of “imprudence” in description and changed wording to “areas of safety concern.”
33	Missed Inspections and Patrols for Electric Circuits	Changed units for missed electric inspections to structures instead of circuit miles. Retained circuit miles for vegetation management inspections.
34	Missed Vegetation Management Inspections	Rearranged ordering of terms HFTD, requirement, and compliance in the metric and descriptions to clarify the definition of the metric.

SPM #	Metric Name (Adopted in D.19-04-020)	Description of Revisions
35	Overhead Conductor Wire Size Compliance in HFTD	Rearranged ordering of terms HFTD, requirement, and compliance in the metric and descriptions to make meaning clearer.
43	GO-95 Corrective Actions in HFTDs	This metric measures how quickly the utilities correct GO 95 deficiencies in HFTDs This metric is calculated as the percentage of corrective actions completed in the past calendar year divided by the total number of corrective actions identified in the past calendar year in patrols and detailed inspections per GO95 in HFTD. Separate metrics are provided for patrols and detailed inspections. Separate metrics are provided for distribution and transmission systems.
44	Gas Overpressure Events	Sempra commented that these are reported quarterly under General Order 112-F; reports should be streamlined rather than given in multiple reports. Staff recommends this metric should be reported annually as an SPM, at the same time increments of the quarterly GO 112-F requirement.

11.3 Staff Recommendations on Modifications to SPMs

Staff recommends that the Commission adopts its final recommendation on modifications and additions to the adopted SPMs in D.19-04-020, provided in Appendix D.

Appendix C

Summary Table of Staff Proposed Safety and Operational Metrics

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
1	SIF related SOMs		
1.1	Rate of SIF Actual (Employee)	Rate of SIF Actual[1] (Employee) is calculated using the formula: Number of SIF-Actual cases among employees x 200,000/employee hours worked, where SIF Actual is counted using the methodology approved by the Edison Electrical Institute's Occupational Health and Safety Committee.	√ *SPM 17*
1.2	Rate of SIF Actual (Contractor)	Rate of SIF Actual (Contractor) is calculated using the formula: Number of SIF-Actual cases among contractors x 200,000/contractor hours worked, where SIF Actual is counted using the methodology approved by the Edison Electrical Institute's Occupational Health and Safety Committee.	√ *SPM 18*

[1] A SIF Actual case as determined using the methodology approved by the Edison Electrical Institute's Occupational Health and Safety Committee.

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
1.3	Rate of SIF Potential (Employee)	Rate of SIF Potential (Employee) is calculated using the formula: Number of SIF Potential cases among employees x 200,000/employee hours worked, where a SIF incident, in this case would be events that could have led to a reportable SIF. Potential SIF incidents are identified using the Edison Electric Institute Safety Classification and Learning (SCL) Model.[2] As a supplemental reporting requirement to the Potential SIF Rate (Employee), PG&E is also expected to provide information on the program area where the SIF Potential occurred, and the lesson learned from the event.	N/A
1.4	Rate of SIF Potential (Contractor)	Rate of SIF Potential (Contractor) is calculated using the formula: Number of SIF Potential incidents among contractors x 200,000/contractor hours worked, where a SIF incident, in this case would be events that could have led to a reportable SIF. Potential SIF incidents are identified using the Edison Electric Institute Safety Classification and Learning (SCL) Model.	N/A

[2] Edison Electric Institute Safety Classification and Learning Model by Dr. Matthew Hallowell https://esafetyline.net/eei/docs/eeiSCLmodel.pdf

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
		As a supplemental reporting requirement to the Potential SIF Rate (Contractor), PG&E is also expected to provide information on the program area where the SIF Potential occurred, and the lesson learned from the event.	
2	Reliability Related SOMs		
Sustained interruption is defined as: "Any interruption not classified as a part of a momentary event. That is, any interruption that lasts more than five minutes."[3]			
2.1	System Average Interruption Duration (SAIDI) (Unplanned)[1]	SAIDI (Unplanned) = average duration of sustained interruptions per metered customer due to all unplanned outages, excluding on Major Event Days, in a calendar year.[4] "Average duration" is defined as: Sum of (duration of interruption * # of customer interruptions) / Total number of customers served.	N/A

[3] *IEEE 1366- Reliability Indices* Presentation, February 19, 2019, at 6.

[4] January 15, 2021 Response of Pacific Gas and Electric Company to Assigned Commissioner's Ruling Regarding Development of Safety and Operational Metrics available here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M359/K864/359864708.PDF

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
		"Duration" is defined as: Customer hours of outages. Includes all transmission and distribution outages.	
2.2	System Average Interruption Duration (SAIDI) (All Outages)	SAIDI (All Outages) = average duration of all sustained interruptions per metered customer due to all outages, including, but not limited to, unplanned outages, planned outages, PSPS outages, and outages on Major Event Days, in a calendar year. "Average duration" is defined as: Sum of (duration of interruption * # of customer interruptions) / Total number of customers served. "Duration" is defined as: Customer hours of outages. Includes all transmission and distribution outages.	N/A
2.3	System Average Interruption Frequency (SAIFI) (Unplanned)	SAIFI (Unplanned) = average frequency of sustained interruptions due to all unplanned outages per metered customer, except on Major Event Days, in a calendar year. "Average frequency" is defined as: Total # of customer interruptions / Total # of customers served. Includes all transmission and distribution outages.	N/A
2.4	System Average Interruption	SAIFI (All Outages) = average frequency of all sustained interruptions per metered customer due to all outages, including, but not limited to,	N/A

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
	Frequency (SAIFI) (All Outages)	unplanned outages, planned outages, outages due to PSPS, and outages on Major Event Days, in a calendar year. “Average frequency” is defined as: Total # of sustained customer interruptions / Total # of customers served Includes all transmission and distribution outages.	
2.5	Customer Average Interruption Duration Index (CAIDI) (Unplanned)	CAIDI (Unplanned) = average duration of sustained outages per impacted metered customer due to all unplanned outages, excluding on Major Event Days, in a calendar year. “Average duration” is defined as: Sum of (duration of interruption * # of customer interruptions) / Total number of impacted customers. “Duration” is defined as: Customer hours of outages. Includes all transmission and distribution outages. This metric can be calculated as: SAIDI (All Outages) / SAIFI (All Outages).	N/A
2.6	Customer Average Interruption Duration Index (CAIDI) (All Outages)	CAIDI (All Outages) = average duration of sustained outages per impacted metered customer due to all outages, including, but not limited to, unplanned outages, planned outages, outages due to PSPS, and outages due to Major Event Days, in a calendar year.	N/A

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
		"Average duration" is defined as: Sum of (duration of interruption * # of customer interruptions) / Total number of impacted customers "Duration" is defined as: Customer hours of outages. Includes all transmission and distribution outages. This metric can be calculated as: SAIDI (All Outages) / SAIFI (All Outages).	
2.7	System Average Customers Impacted (All Outages)	System Average Customers Impacted (All Outages) = average number of all metered customers experiencing sustained interruptions due to all outages, including, but not limited to, unplanned outages, planned outages, outages due to PSPS, and outages due to Major Event Days, in a calendar year; "Average customers" is defined as: Number of customers impacted / total number of customers served. Includes all transmission and distribution outages.	N/A

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
	PSPS Related SOMs		
	Pursuant to D.15-05-042, "[t]he electric investor-owned utilities must report on lessons learned from each de-energization event, including instances when de-energization protocols are initiated, but de-energization does not occur, in order to further refine de-energization practices."[5] The reporting period for a PSPS event begins with the first notification of an impending power shut-off. The PSPS ends when the last circuit is restored and customers and critical facilities are notified.[6]		
2.8	Number of PSPS events in a calendar year		N/A
2.9	Duration of each PSPS Event in hours in a calendar year		N/A
2.10	Number of Customers Impacted by each PSPS Event in a calendar year		N/A

[5] D.19-05-042, Appendix A, at A3.

[6] D.19-05-042 Appendix A, at A8-A9.

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
System Average Outages due to Vegetation and Equipment Damage in HFTD Areas Report *System Average Outages due to Vegetation and Equipment Damage* SOMs specific to Tier 2 and 3 High Fire Threat District.[7] For Vegetation and Equipment Damage *in HFTD (Major Event Days & (Non-Major Event Days)* SOMs, PG&E should delineate outages due to contact with vegetation versus outages caused by equipment, and distribution versus transmission assets. For equipment damage-related outages, the metrics should also be segregated by overhead versus underground.			
2.11	System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Major Event Days)	Average number of sustained outages on Major Event Days per 100 circuit miles in HFTD per metered customer, in a calendar year, where each sustained outage is defined as: total number of customers interrupted / total number of customers served	N/A
2.12	System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Non-Major Event Days)	Average number of sustained outages on Non-Major Event Days per 100 circuit miles in HFTD per metered customer, in a calendar year, where each sustained outage is defined as: total number of customers interrupted / total number of customers served	N/A

7 Decision for Adopting the Work Plan for the Development of Fire Map 2 (D.17-01-009), as modified by Decision Amending the Work Plan for the Development of Fire Map 2 (D.17-06-024). Additional Tier information.

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
3	**Electricity Related SOMs**		
Wires Down Related SOMs **A *Wires Down* event is defined as follows:** A Wires Down event occurs when a normally energized overhead primary or secondary distribution or transmission conductor satisfies one or more of these conditions: 1. A conductor or splice becomes broken, 2. A conductor is dislodged from its intended design position due to either malfunction of its attachment points and/or supporting structures or contact with foreign objects (including vegetation), 3. A conductor's distance from the ground, structures, or foreign objects (not including vegetation) falls below applicable minimum clearances specified in General Order 95, 4. A conductor comes into contact with communication circuits, guy wires, or conductors of a lower voltage, or 5. A power pole carrying normally energized conductors leans by more than 45 degrees in any direction relative to the vertical reference when measured at ground level. This Wires Down events definition excludes vegetation growth-related clearance violations in which the conductor does not otherwise violate the five conditions listed above. This definition includes service drops. Primary distribution and transmission circuit miles are counted separately, and then added together even if they are found on the same spans. This definition applies to **all Wires Down** related metrics.			
3.1	Wires Down Major Event Days in HFTD Areas	Number of Wires Down events on Major Event Days involving either overhead primary or secondary distribution or overhead transmission circuits divided by total circuit miles of overhead primary distribution and transmission lines x 1,000, in HFTD Areas in a calendar year.	√ *(Except that SPM #2 does not specify HFTD and is reported as number instead of*

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
			rate of Wire-Down events)
3.2	Wires Down Non-Major Event Days in HFTD Areas	Number of Wires Down events on Non-Major Event Days involving either overhead primary or secondary distribution or overhead transmission circuits divided by (Total circuit miles of overhead primary distribution and transmission lines) x 1,000, in HFTD Areas, in a calendar year. Distribution and transmission circuit miles are counted separately and then added together even if they are found on the same spans.	√ (*Except that SPM #1 does not specify HFTD and is reported as number instead of rate of Wire-Down events)*
3.3	Wires Down Red Flag Warning Days in HFTD Areas	Number of Wires Down events on Red Flag Warning Days involving either overhead primary or secondary distribution or overhead transmission circuits divided by total circuit miles of overhead primary distribution and transmission lines x 1,000, in HFTD, in a calendar year.	N/A
Patrols, Inspections & Compliance Related SOMs			
3.4	Overhead Distribution Patrols Compliance in HFTD Areas	Overhead Distribution Patrols Compliance in HFTD: Total number of overhead electric distribution structures that fell below the minimum patrol frequency requirements divided by the total number of overhead electric distribution structures that required patrols, in HFTD area in past calendar year. where,	√ (*Except that SPM #33 includes all areas)*

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
		“Minimum patrol frequency” refers to the frequency of patrols as specified in GO 165. “Structures” refers to electric assets such as transformers, switching protective devices, capacitors, lines, poles, etc.	
3.5	Overhead Distribution Detailed Inspections Compliance in HFTD Areas	Overhead Distribution Detailed Inspections Compliance in HFTD: Total number of structures that fell below the minimum inspection frequency requirements divided by the total number of structures that required inspection, in HFTD area in past calendar year. where, “Minimum inspection frequency” refers to the frequency of scheduled inspections as specified in GO 165. “Structures” refers to electric assets such as transformers, switching protective devices, capacitors, lines, poles, etc.	√ *(Except that SPM #33 includes all areas)*
3.6	Overhead Transmission Patrols Compliance in HFTD Areas	Same as SOM #3.4 definition, except for Transmission instead of Distribution. Overhead Transmission Patrols Compliance in HFTD: Total number of structures that fell below the minimum patrol frequency requirements divided by the total number of structures that required patrols, in HFTD area in past calendar year. where,	√ *(Except that SPM #33 includes all areas)*

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
		"Minimum patrol frequency" refers to the frequency of patrols requirements, as applicable. "Structures" refers to electric assets such as transformers, switching protective devices, capacitors, lines, poles, etc.	
3.7	Overhead Transmission Detailed Inspections Compliance in HFTD Areas	Overhead Transmission Detailed Inspections Compliance in HFTD: Total number of structures that fell below the minimum inspection frequency requirements divided by the total number of structures that required inspection, in HFTD area in past calendar year. where, "Minimum inspection frequency" refers to the frequency of scheduled inspections requirements, as applicable. "Structures" refers to electric assets such as transformers, switching protective devices, capacitors, lines, poles, etc.	√ (*Except that SPM #33 includes all areas)*
3.8	*Distribution Vegetati on/Conductor Clearance Inspections in HFTD Areas*	Distribution Vegetation/Conductor Clearance Inspections Compliance in HFTD Areas*:* Total circuit miles of Vegetation/Conductor Clearance Inspections on distribution circuits that fell below the minimum Vegetation/Conductor Clearance Inspections frequency divided by the total distribution circuit miles that required vegetation Vegetation/Conductor Clearance Inspections, in HFTD area, in past calendar year.	√ *SPM #34* *for distribution* *Except that SPM #34 includes all areas*

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
		"Vegetation/Conductor Clearance Inspections frequency" refers to the frequency of utilities' scheduled inspections, as applicable. GO 95 specifies the minimum Vegetation/Conductor Clearance requirements.	
3.9	*Transmission Vegetation/Conductor Clearance Inspections in HFTD Areas*	Transmission Vegetation/Conductor Clearance Inspections Compliance in HFTD Areas: Total circuit miles of Vegetation/Conductor Clearance Inspections on transmission circuits that fell below the minimum Vegetation/Conductor Clearance Inspections frequency divided by the total transmission circuit miles that required vegetation Vegetation/Conductor Clearance Inspections, in HFTD area, in past calendar year. "Vegetation/Conductor Clearance Inspections frequency" refers to the frequency of utilities' scheduled inspections, as applicable. GO 95 specifies the minimum Vegetation/Conductor Clearance requirements.	√ *SPM #34* *for transmission Except that SPM #34 includes all areas*
3.10	Backlog Compliance Metrics in HFTD	Total number of overdue overhead electric work orders in high fire threat districts that exceeded the maximum allowable/allotted time frame to complete the work order divided by the total number of closed or still-open overhead electric work orders in high fire threat districts in past calendar year, evaluated at the end of the year. where,	√ *SPM #42*

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
		"Work Orders" include maintenance, and corrective work orders (including those generated as a result of patrols and detailed inspections), electric system hardening, and Enhanced Vegetation Management programs.	
3.11	Electric Emergency Response Time[1]	Percentage of time that utility personnel respond (are on site) within 60 minutes after receiving a 911 call (electric related), with onsite defined as arriving at the premises to which the call relates.	√ (*Except that SPM #3 is worded slightly different)*
Ignitions & Wildfires Related SOMs "Ignition" refers to the number of CPUC-Reportable ignitions and any other ignitions determined by the Authority Having Jurisdiction to originate from utility infrastructure.[8]			
3.12	Number of CPUC-Reportable Ignitions in HFTD Areas (Distribution)	Number of CPUC-Reportable Ignitions involving overhead distribution circuits in HFTD Areas	√ (*Except that SPM #4 in all areas and does not include the updated SOM definition)*

[8] The number of powerline-involved fire incidents annually reportable to the CPUC per Decision 14-02-015. A reportable fire incident includes all of the following: 1) Ignition is associated with a utility's powerlines and 2) something other than the utility's facilities burned and 3) the resulting fire traveled more than one meter from the ignition point.

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
3.13	Percentage of CPUC-Reportable Ignitions in HFTD (Distribution)	Number of CPUC-reportable Ignitions involving overhead transmission circuits in HFTD Areas.	N/A
3.14	Number of CPUC-Reportable Ignitions in HFTD (Transmission)	Same as 3.12, except for Transmission instead of Distribution	√ (*Except that SPM #4 in all areas and does not include the updated SOM definition)*
3.15	Percentage of CPUC-Reportable Ignitions in HFTD (Transmission)	Same as 3.13, except for Transmission instead of Distribution	N/A
4	**Natural Gas Related SOMs**		
4.1	Number of Gas Dig-Ins per 1000 USA tickets on Transmission and Distribution pipelines	Number of Excavation Damages per 1000 Underground Service Alert (USA) tickets by any party on all pipelines.	√ *SPM #5*
4.2	Number of Overpressure (OP) Events	Overpressure events as reportable under GO112-F 122.2(d)(5).	.√ *SPM #44*

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
4.3	Normalized Overpressure Events	Number of Large Overpressure Events normalized to the number of pressure transducers on the gas system. (Overpressure events as reportable under GO112-F 122.2(d)(5)).	N/A
4.4	Time to Respond On-site to Emergency Notification	Time to Respond On-site to Gas Emergency Notification, reported in increments as per GO 112-F 123.2 (c).	√ *SPM #11*
4.5	Gas Shut-In Time, Mains	Time to shut-in gas when gas release occurs on a main,-reported in increments per GO 112-F 123.2 (c).	√ *SPM #8*
4.6	Gas Shut-In Time, Services	Time to shut-in gas when gas release occurs on a service, reported in increments per GO 112-F 123.2 (c).	√ *SPM #9*
4.7	Uncontrolled Release of Gas on Transmission Pipelines	The number of leaks, ruptures, or other loss of containment on transmission lines for the reporting period.	N/A
4.8	Time to Resolve Hazardous Conditions	Time starts when the utility first receives the report and ends when a utility's qualified representative determines, per the utility's emergency standards, that the reported leak is not hazardous or the utility's representative completes actions to mitigate a hazardous leak and render it as being non-hazardous (i.e., by shutting-off gas supply, eliminating subsurface	N/A

Number Index	Staff Proposed SOMs	Definition	Staff Proposed Modification or Additional SPMs
		leak migration, repair, etc.) per the utility's standards. Response time is reported in increments per GO 112-F 123.2 (c).	
5	**Clean Energy Goals**		
5.1	Clean Energy Goals Compliance Metrics	Commission established clean energy targets that it has failed to meet during the reporting period	N/A

END APPENDIX C