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

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

R.20-07-013
(Filed July 16, 2020)

NOT CONSOLIDATED

Application of Pacific Gas and Electric
Company (U 39 M) to Submit Its 2024
Risk Assessment and Mitigation Phase

A.24-05-008
(Filed May 15, 2024)

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Application of Pacific Gas and Electric
Company for Authority, Among Other
Things, to Increase Rates and Charges
for Electric and Gas Service Effective
on January 1, 2027.

A.25-05-009
(Filed May 15, 2025)

(U 39 M)

**PACIFIC GAS AND ELECTRIC COMPANY'S (U39M)
SAFETY AND OPERATIONAL METRICS REPORT
(ATTACHMENT A SUPPORTING DOCUMENTATION
FILED ON ARCHIVAL GRADE DVD)**

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Dated: April 1, 2026

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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SAFETY AND OPERATIONAL METRICS REPORT
(ATTACHMENT A SUPPORTING DOCUMENTATION
FILED ON ARCHIVAL GRADE DVD)**

Pacific Gas and Electric Company (PG&E) hereby submits this semi-annual Safety and Operational Metrics Report in compliance with California Public Utilities Commission Decision (D.) 21-11-009. This is PG&E’s ninth report which covers the period from January 1 to December 31, 2025. The report is provided as Attachment A.

To assist in the review of this report, PG&E has identified material changes from the last report in blue font. PG&E has done this as a courtesy to parties. PG&E asks for the parties’ understanding should there be any inadvertent mistakes in our good faith attempt at this formatting.

Separately, PG&E is concurrently filing and serving a “Notice of Availability of Pacific Gas and Electric Company’s ‘Safety and Operational Metrics Report:

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT A

*(Attachment A Supporting Documentation
Filed On Archival Grade DVD Due To Format And Size)*

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT

APRIL 1, 2026



PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT
APRIL 1, 2026

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INTRODUCTION

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 1.0**
4 **INTRODUCTION**

5 For this report Pacific Gas and Electric Company is identifying material changes
6 in blue font.

7 **A. Introduction**

8 Pacific Gas and Electric Company (PG&E or the Company) respectfully
9 submits this **ninth** semi-annual Safety and Operational Metrics (SOM) Report.
10 This report is submitted in compliance with California Public Utilities Commission
11 (CPUC or Commission) Decision (D.) 21-11-009 concerning the Risk-Based
12 Decision-Making Framework proceeding (Risk OIR).

13 At PG&E, nothing is more important than the safety of our customers,
14 employees, contractors, and communities. We strive to be the safest,
15 most-reliable gas and electric Company in the United States, while keeping
16 customer affordability at the forefront of our decisions and actions. This SOM
17 report demonstrates PG&E’s commitment to overseeing safe operations and,
18 where needed, driving progress to reduce risk and improve performance. SOMs
19 are embedded in our internal processes to give Company leaders visibility into
20 performance to identify negative trends and take swift corrective actions to
21 prevent harm. These metrics are central to safety performance across the
22 Company.

23 PG&E has approached each SOM on a metric-by-metric basis. More
24 specifically, PG&E evaluated our historical and current year performance and
25 available benchmarking data, and established objectives that align with our
26 commitment to safety. For example, a metric where PG&E already performs in
27 the first quartile may not demand dramatic improvement, but could require
28 consistent monitoring to ensure that performance remains at acceptable levels.
29 For metrics that include Major Event Days (MED), PG&E will use the information
30 to help ensure that our infrastructure is adaptable to an environment rapidly
31 changing due to climate change. For some metrics, the Company has found
32 opportunity to continue to drive safety performance through ongoing or future
33 programs that are described in each chapter of this report.

1 **B. Background and Requirements**

2 As part of the decision for PG&E’s Plan of Reorganization (D.20-05-053),
3 the Commission envisioned a set of metrics that provides a “holistic quantitative
4 and qualitative ‘indicator light’ method to evaluate key metrics directly associated
5 with PG&E safe and operational performance.”

6 On November 9, 2021, through the Commission’s Risk OIR that began on
7 November 17, 2020, the Commission issued D.21-11-009 (the Risk OIR
8 decision) establishing 32 SOMs. Ordering Paragraph 5 of that decision requires
9 that:

10 PG&E shall report its Safety and Operational Metrics as follows. PG&E
11 shall, on a semi-annual basis, serve and file its SOMs report in Rulemaking
12 20-07-013, any successor Safety Model Assessment Proceeding, and its
13 most recent or current General Rate Case and Risk Assessment and
14 Mitigation Phase proceedings starting March 31, 2022, and continuing
15 annually at the end of September and March thereafter, with the March
16 reports covering the 12 months of the previous calendar year (i.e., January
17 through December) and the September reports providing data for January
18 through June of the current year. PG&E shall concurrently send a copy of
19 its semi-annual SOMs reports to the Director of the Commission’s Safety
20 Policy Division and to RASA_Email@cpuc.ca.gov. PG&E shall:

- 21 a) Report on each SOM, using data for the preceding 12 months and
22 providing all available historical data;¹
- 23 b) For each SOM, provide a proposed target for the year following the
24 reporting period for each metric and a 5-year target, with the proposed
25 target represented as specific values, ranges of values, a rolling
26 average, or another specified target value, except for our final adopted
27 SOM #s 1.3, 2.3, 3.1, 3.3, 3.5, and 3.6 for which PG&E may provide
28 directional targets;
- 29 c) For each SOM, provide a narrative description of the rationale for
30 selecting the target proposed and why a specific value, a range of
31 values, a rolling average or another type of target is selected;
- 32 d) For each SOM, provide a narrative description of progress towards the
33 proposed annual and 5-year targets;
- 34 e) For each SOM, provide a narrative description of any substantial
35 deviation from prior trends based on quantitative and qualitative
36 analysis, as applicable;
- 37 f) For each SOM, provide a brief description of current and future activities
38 to meet the proposed targets; and

1 These historic data files are provided through a Notice of Availability (NOA) being filed concurrently with this report. An index of these files is provided as an attachment to the NOA.

1 g) Provide the Commission's Safety and Policy Division with a copy of any
2 report filed more frequently than semi-annually with the Commission that
3 contains SOMs, at the same time the report is filed.²

4 This report outlines [PG&E's 2025 performance](#) and is organized into
5 32 individual metric chapters as defined in Attachment A of D.21-11-009. Each
6 chapter provides discussion on performance and progress against 1- and 5-year
7 targets.

8 Additionally, Order Paragraph 7 of D.21-11-009 states:

9 PG&E shareholders shall pay for an independent third-party audit of
10 PG&E's SOMs data collection and reporting processes within the next
11 three years to ensure accuracy and compliance with SOMs reporting
12 requirements.

13 The required audit was performed by Filsinger Energy Partners (FEP) with
14 the final report submitted to the Commission on June 9, 2025.³ [Section A,](#)
15 ["Audit Results,"](#) was included in each metric chapter of the [September 30, 2025](#)
16 [report to capture FEP audit findings and PG&E's response to the audit findings.](#)
17 [In the April 1, 2026 report, Section A appears only in chapters with unresolved](#)
18 [findings or pending corrections from September 30, 2025. The table below](#)
19 [provides a summary of these audit findings and the actions taken to address](#)
20 [them.](#)

2 PG&E understands this requirement to not include one-time event triggered reports (e.g., Electric Incident Reports). PG&E can provide such reports upon request. Note that PG&E provided quarterly reports as part of the Wildfire Mitigation Plan to the Commission through June 2021 but are now submitted to the Office of Energy Infrastructure Safety. These reports can be found online at [PG&E's Wildfire Mitigation Plan webpage](#).

3 PG&E SAFETY AND OPERATIONAL METRICS AUDIT REPORT, Prepared for: CPUC, June 9, 2025 (hereinafter "Audit Report").

**TABLE 1-1
SUMMARY OF FEP AUDIT FINDINGS**

Metric	Accuracy Finding	Corrective Action Taken	Status	More Information (Ch./Pg.)
Metric 2.3: System Average Outages due to Vegetation and Equipment Damage in High Fire Threat District (HFTD) Areas MEDS	Significant	<p>The Other Findings for this metric were "Discrepancy between CESO data pulled monthly and annually." These findings have been resolved. PG&E clarified that not all outages may have been officially closed at the time of the 2023 mid-year report, and outages may still be reviewed and changed months after the fact due to internal findings.</p> <p>Regarding the significant HFTD discrepancies finding, this finding is closed with respect to 2025 and going forward, but remains open with respect to impacts of prior reporting years of the HFTD issues discussed in Chapter 2.3.</p>	<p>The Other Findings have been resolved.</p> <p>The HFTD designations finding is pending final resolution.</p>	2.3-1
Metric 2.4: System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Non-MEDs)	Significant	See Metric 2.3	See Metric 2.3	2.4-1
Metric 3.1: Wires Down MED in HFTD Areas (Distribution)	Significant	<p>The Other Findings for this metric were "ILIS as the database of record impacts event counts." These findings have been resolved. ILIS continues to be the database of record. However, this does not impact the ability to report this metric accurately.</p> <p>With respect to the significant findings, which identified HFTD discrepancies, the Outage Foundry Ontology dataset has been joined with the latest HFTD version dataset in Foundry to create an outage dataset with a single HFTD designation for our distribution level outages coming from our Integrated Logging and Information System (ILIS) source system.</p>	Resolved	3.1-1
Metric 3.2: Wires Down Non-MED in HFTD Areas (Distribution)	Significant	See Metric 3.1	See Metric 3.1	3.2-1

**TABLE 1-1
SUMMARY OF FEP AUDIT FINDINGS
(CONTINUED)**

Metric	Accuracy Finding	Corrective Action Taken	Status	More Information (Ch./Pg.)
Metric 3.5: Wires Down Red Flag Warning Days in HFTD Areas (Distribution)	Significant	See Metric 3.1	See Metric 3.1	3.5-2
Metric 3.7: Missed Overhead Distribution Patrols in HFTD Areas	Significant	This finding was based on a conclusion that manual calculation of asset inspection due dates across multiple program years and strategies led to data errors. The finding for 2024-2025 was resolved in the September 30, 2025 filing. We plan to correct 2022-2023 in the 9/30/26 filing, but we do not plan to correct 2021. In addition, we will move to digitized patrols collecting structure-level data by December 31, 2026.	The findings are partially resolved with an anticipated resolution date of 9/30/26.	3.7-2
Metric 3.8: Missed Overhead Distribution Detailed Inspections in HFTD Areas	Significant	This finding was based on a conclusion that manual calculation of asset inspection due dates across multiple program years and strategies led to data errors. The finding for 2024-2025 was resolved in the 9/30/25 filing. We plan to correct 2022-2023 in the 9/30/26 filing, but we do not plan to correct 2021.	See Metric 3.7	3.8-2
Metric 3.11: GO-95 Corrective Actions in HFTDs	Significant	This finding was due to erroneous calculations from Vegetation Management, Transmission, and Distribution. The finding is resolved. The erroneous calculations for 2021 were corrected in the September 2025 report. As part of the audit, PG&E also identified a population of electric corrective notifications with erroneous compliance due dates, investigated underlying causes and established corrective actions. The corrective actions for Distribution were tracked by Corrective Action Plan and completed on December 15, 2025, prior to the due date of December 31, 2025.	Resolved	3.11-2

1 **C. PG&E’s Approach to SOMs Target Setting**

2 PG&E’s approach to SOMs was developed around four pillars for
3 developing targets that align with the Commission’s objective for this report:

- 4 1) Targets should be set at levels indicating “insufficient progress” or “poor
5 performance” within the context of the Enhanced Oversight and
6 Enforcement Process;
- 7 2) Targets should be set at a reasonable and attainable level, including, but not
8 limited to the following considerations:
 - 9 a) Historical data and trends;
 - 10 b) Benchmarking;
 - 11 c) Applicable federal, state, or regulatory requirements;
 - 12 d) Resources;
- 13 3) Targets should be set at levels where performance can be sustained over
14 time; and
- 15 4) Targets should be set and evaluated in consideration of a holistic qualitative
16 and quantitative view including additional contextual information and factors.

17 With these criteria, PG&E sought to develop targets for each metric that
18 generally maintain performance for well-performing metrics or drive performance
19 improvement to satisfactory levels of safe and reliable service. As required by
20 the decision, within each metric chapter PG&E provides the rationale behind the
21 selection of the 1- and 5-year targets. On their own, metrics can fail to tell a
22 complete story and may not provide crucial detail or context that is necessary for
23 a proper evaluation of performance or progress. Recognizing that, the
24 Commission’s Risk OIR decision requires PG&E to provide a narrative-driven
25 report that gives the Commission further insight on how PG&E’s safety and
26 operational programs are progressing towards targets or if performance is
27 deviating from target and trend, and to state current and future activities that will
28 drive performance towards target or trend.

- 29 5) PG&E and the Commission’s Safety Policy Division (SPD) continue to
30 participate in monthly meetings to discuss questions arising from prior
31 reports, or, in some instances to preview expected performance or
32 target-setting for upcoming reports. These meetings have proven
33 successful in providing PG&E ongoing guidance for target-setting and as an
34 effective way to resolve questions through metric owner presentations.

1 Additionally, PG&E uses feedback from these meetings to engage
2 leadership and to address SPD recommendations where possible. PG&E
3 will continue to drive performance improvement where appropriate, and
4 prioritize the safety of our customers, contractors, and employees.

5 **D. Summary of Metric Performance Against Targets**

6 This report shows that PG&E is exceeding or maintaining performance
7 expectations against its 2025 targets for all 32 of the SOMs metrics.

8 PG&E has updated the one-year targets for 20 of the 32 metrics evaluated
9 in this report. 12 metrics carry the same one-year targets from the previous year
10 and PG&E includes a justification, on a case-by-case basis, on why maintaining
11 metric performance is the appropriate approach.

12 Below is a summary of the performance and targets for each metric. The
13 details for each metric can be found in the metric report chapters that follow.

**TABLE 1-2
SUMMARY OF 2025 METRIC PERFORMANCE AND TARGETS**

#	Metric	2025 Performance	2025 Target	2026 Target
Safety				
1.1	Rate of Serious Injury or Fatality (SIF) Actual (Employee)	Rate: 0.04	Rate: 0.06	Rate: 0.05
1.2	Rate of SIF Actual (Contractor)	Rate: 0.02	Rate: 0.10	Rate: 0.06
1.3	SIF Actual (Public)	1	Demonstrate progress towards 0	Demonstrate progress towards 0
Reliability				
2.1	System Average Interruption Duration (Unplanned)	3.02 hrs. per customer	3.68 - 5.69 hrs. per customer	5.69 hrs. per customer
2.2	System Average Interruption Frequency (Unplanned)	1.428 outages per customer	1.555 - 2.405 outages per customer	2.405 outages per customer
2.3	System Average Outages due to Vegetation and Equipment Damage in HFTD Areas MEDs	367 Customers Experiencing Sustained Outages (CESO) due to 5 MED	Maintain	Maintain
2.4	System Average Outages due to Vegetation and Equipment Damage in HFTD Areas (Non-MEDs)	1,750 CESO	2,112 - 3,266 CESO	3,266 CESO
Electric				
3.1	Wires Down MED in HFTD Areas (Distribution)	13.90 wires down (WD) events/1,000 miles due to 5 MEDs	Maintain/107.50	Maintain/107.58
3.2	Wires Down Non-MED in HFTD Areas (Distribution)	30.32 WD events/1,000 miles	Maintain/45.08	Maintain/45.12
3.3	Wires Down MED in HFTD Areas (Transmission)	1.302 WD events/1,000 miles due to 5 MEDs	Maintain/8.433	Maintain/<8.433
3.4	Wires Down Non-MED in HFTD Areas (Transmission)	1.674 WD events/1,000 miles	Maintain/≤4.392	Maintain/≤4.392
3.5	Wires Down Red Flag Warning Days in HFTD Areas (Distribution)	0 WD due to 0 WD events	Maintain/0.00068	Maintain/0.00069
3.6	Wires Down Red Flag Warning Days in HFTD Areas (Transmission)	0 WD due to 0 WD events	Maintain	Maintain

**TABLE 1-2
SUMMARY OF 2025 METRIC PERFORMANCE AND TARGETS
(CONTINUED)**

#	Metric	2025 Performance	2025 Target	2026 Target
Patrols and Inspections				
3.7	Missed Overhead Distribution Patrols in HFTD Areas	0%	0% – 4%	0% – 4%
3.8	Missed Overhead Distribution Detailed Inspections in HFTD Areas	0.02%	0% – 2%	0% – 2%
3.9	Missed Overhead Transmission Patrols in HFTD Areas	0.00%	0.00% – 0.03%	0.0% – 0.02%
3.10	Missed Overhead Transmission Detailed Inspections in HFTD Areas	0.00%	0.00% – 0.03%	0.0% – 0.02%
3.11	GO-95 Corrective Actions in HFTDs	77.7%	73.8%	65.4%
3.12	Electric Emergency Response Time	Average: 29 min Median: 27 min	Average: 44 min Median: 43 min	Average: 44 min Median: 43 min
Ignitions and Wildfire				
3.13	Number of CPUC-Reportable Ignitions in HFTD Areas (Distribution)	53 ignitions	70 – 128 ignitions	70 – 128 ignitions
3.14	Percentage of CPUC-Reportable Ignitions in HFTD Areas (Distribution)	2.15/1,000 circuit miles	2.83 – 5.18/1,000 circuit miles	2.86 – 5.24/1,000 circuit miles
3.15	Number of CPUC-Reportable Ignitions in HFTD Areas (Transmission)	4 ignitions	4 – 12 ignitions	4 – 12 ignitions
3.16	Percentage of CPUC-Reportable Ignitions in HFTD Areas (Transmission)	0.74/1,000 circuit miles	0.74 – 2.23/1,000 circuit miles	0.74 – 2.23/1,000 circuit miles

**TABLE 1-2
SUMMARY OF 2025 METRIC PERFORMANCE AND TARGETS
(CONTINUED)**

#	Metric	2025 Performance	2025 Target	2026 Target
Gas				
4.1	Number of Gas Dig-Ins per 1,000 USA tickets on Transmission and Distribution pipelines	1.18	≤1.94	≤1.80
4.2	Number of Overpressure Events	6	≤10	≤9
4.3	Time to Respond On-Site to Emergency Notification	Average (mins): 19.8 Median (mins): 18.2	Average (mins): ≤21.3 Median (mins): ≤19.6	Average (mins): ≤21.2 Median (mins): ≤19.5
4.4	Gas Shut-In Times, Mains	81.9 mins	≤87.4 mins	≤87.7 mins
4.5	Gas Shut-In Times, Services	30.6 mins	≤39.8 mins	≤39.0 mins
4.6	Uncontrolled Release of Gas on Transmission Pipelines	1,590	≤3,440	≤2,140
4.7	Time to Resolve Hazardous Conditions	126 mins	≤173.9 mins	≤169.5 mins
Clean Energy				
5.1	Clean Energy Goals Compliance Metric	2,666.7	≥2,666.1 MW	≥3,054.1 MW
Quality of Service				
6.1	Quality of Service Metric	7 sec	≤15 sec	≤15 sec

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 1.1
RATE OF SIF ACTUAL
(EMPLOYEE)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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RATE OF SIF ACTUAL
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 1.1**
4 **RATE OF SIF ACTUAL**
5 **(EMPLOYEE)**

6 The material updates to this chapter since the September 30, 2025, report are
7 identified in blue font.

8 **A. (1.1) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metric (SOM) 1.1 – Rate of Serious Injury and
11 Fatality (SIF) Actual (Employee) is defined as:

12 *Rate of SIF Actual (Employee) is calculated using the formula: Number*
13 *of SIF-Actual cases among employees x 200,000/employee hours worked,*
14 *where SIF Actual is counted using the methodology developed by the*
15 *Edison Electric Institute’s (EEI) Occupational Safety and Health Committee*
16 *(OS&HC).*

17 **2. Introduction of Metric**

18 Pacific Gas and Electric Company’s (PG&E or the Company) safety
19 stand is, “Everyone and Everything Is Always Safe.” This includes our
20 employee and contractor workforce, as well as the public. We remain
21 committed to building an organization where every work activity is designed
22 to facilitate safe working conditions and every member of our workforce is
23 encouraged to speak up if they see an unsafe or risky condition with the
24 confidence that their concerns and ideas will be heard and addressed. As
25 part of this stand, PG&E is committed to employee safety.

26 As defined by Decision (D.) 21-11-009, the SIF Actual (Employee) SOM
27 calculation is applied to PG&E’s existing [work-related](#) injury and SIF
28 datasets. The data were analyzed and reported under this definition
29 beginning in March of 2022.

30 The EEI OS&HC has oversight over the SIF Criteria, which are reviewed
31 annually and updated based on additional learnings from injury classification
32 to provide further clarification or criteria for the following year. The EEI SIF
33 Criteria were revised and published August 1, 2024, and became effective

1 January 1, 2025.¹ The criteria are included in Appendix 9 of the EEI Safety
2 Classification and Learning (SCL) Model guidance.² The SIF Criteria
3 include the following definitions:

- 4 • **Life-Threatening:** A physical injury that if not immediately addressed is
5 likely to lead to the death of the affected individual and will usually
6 require the intervention of life sustaining support by external emergency
7 response personnel or colleagues.
- 8 • **Life-Altering:** A physical injury that results in permanent loss of use of
9 an internal organ, body function, or body part.

10 The SIF Criteria includes these serious injury types:

- 11 1) Fatalities;
- 12 2) Amputations (involving bone), excluding distal phalanx **unless thumb,**
13 **index, or great toe;**
- 14 3) Head trauma that results in a traumatic brain injury (TBI), intracranial
15 bleeding, or loss of consciousness for greater than 30 minutes;
- 16 4) Injury or trauma to vital organs to include brain, spinal cord, heart, lungs,
17 kidneys, liver, spleen, large and small intestine, and stomach;
- 18 5) Bone fractures requiring surgery for repair (pins, rods, screw, plates,
19 wires, etc.) excludes fingers and toes;
- 20 6) Acute traumatic herniated disc with neurologic deficit—sensory or motor.
- 21 7) 2nd degree burn (10 percent body surface), 3rd – degree burn
22 (5 percent of body surface), or 3rd degree burn requiring skin graft;
- 23 8) Eye injuries resulting in permanent vision loss or change in vision;
- 24 9) High pressure injection injuries requiring surgical debridement and
25 irrigation;
- 26 10) **Medically diagnosed** Heat Stroke;
- 27 11) Dislocation of the hip, elbow, or knee, **does not include dislocation of the**
28 **patella (kneecap);**
- 29 12) Electrical contact injuries;
- 30 13) Vascular trauma requiring surgery;

1 [EEI Serious Injury and Fatality \(SIF\) Criteria.](#)

2 EEI Safety Classification and Learning (SCL) model guidance. EEI SIF Criteria are in
Appendix 9 of the [SCL model report.](#)

1 14) Acute chemical or radiological exposure resulting in injury to vital
2 organs to include brain, spinal cord, heart, lungs, kidneys, liver, spleen,
3 large and small intestine, and stomach;

4 15) Other: **Injuries classified as “other” must meet the life-threatening or**
5 **life-altering definition.**

6 PG&E’s SIF Prevention Program was deployed at the end of 2016 to
7 establish a cause evaluation process for **employee and contractor** serious
8 safety incidents. This program was established to create consistency and
9 guidance in classifying and evaluating serious safety incidents for all
10 employees with the goal of reducing the number and severity of safety
11 incidents that result in a SIF. The program’s objective is to learn from prior
12 safety incidents by performing cause evaluations on each SIF Actual (SIF-A)
13 and SIF Potential (SIF-P) incident, implementing corrective actions, and
14 sharing key findings and learnings across the enterprise.

15 From 2017 to 2020, PG&E classified SIF-A incidents based on the job
16 task and whether a life-altering or life-threatening injury or fatality occurred.
17 In August of 2020, PG&E adopted EEI’s Safety Classification and Learning
18 (SCL)³ model to classify its SIF incidents (See Figure 1-1.1). The EEI SCL
19 model classifies incidents into **seven** categories: High-Energy SIF (HSIF),⁴
20 Low-Energy SIF LSIF),⁵ Potential SIF (PSIF),⁶ Capacity,⁷ Exposure,⁸
21 Success,⁹ and Low Severity.¹⁰

3 EEI SCL Model available here: <https://www.safetyfunction.com/scl-model>.

4 *Id.* at p. 19, HSIF is defined as: “Incident with a release of high-energy in the absence of a direct control where a serious injury is sustained.”

5 *Id.* at p. 19, LSIF is defined as: “Incident with a release of low energy in the absence of a direct control where a serious injury is sustained.”

6 *Id.* at p. 19, PSIF is defined as: “Incident with a release of high-energy in the absence of a direct control where a serious injury is not sustained.”

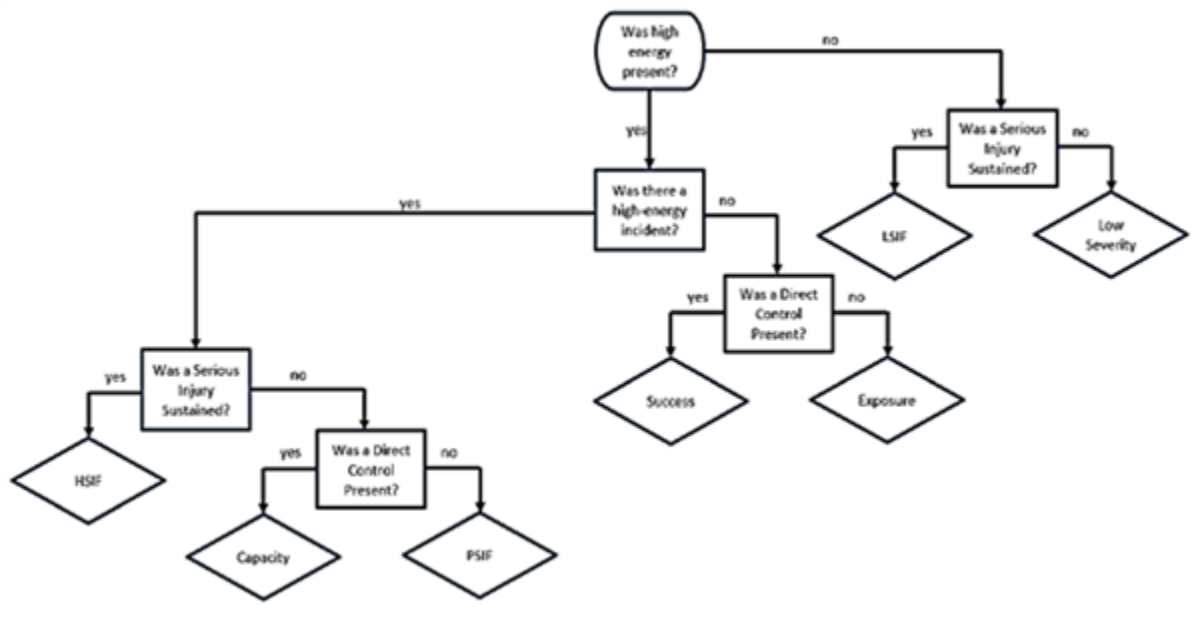
7 *Id.* at p. 19, Capacity is defined as: “Incident with a release of high-energy in the presence of a direct control where a serious injury is not sustained.”

8 *Id.* at p. 19, Exposure is defined as: “Condition where high-energy is present in the absence of a direct control.”

9 *Id.* at p. 19, Success is defined as: “Condition where a high-energy incident does not occur because of the presence of a direct control.”

10 *Id.* at p. 19, Low Severity is defined as: “Incident with a release of low energy where no serious injury is sustained.”

**FIGURE 1.1-1
EEI SCL MODEL FLOWCHART**



1 Adopting the EEI SCL model has improved the SIF Program by bringing
 2 a consistent and objective approach to reviewing and classifying SIF
 3 incidents across the Company and industry. The EEI SCL model allows the
 4 Company to focus its safety and risk mitigation efforts on the most serious
 5 outcomes and highest risk work where a high-energy is present, or a
 6 high-energy incident occurred. The EEI SCL model is also used for the
 7 Employee SIF-A Safety Performance Metric (SPM) and is aligned with the
 8 California utilities.

9 **B. (1.1) Metric Performance**

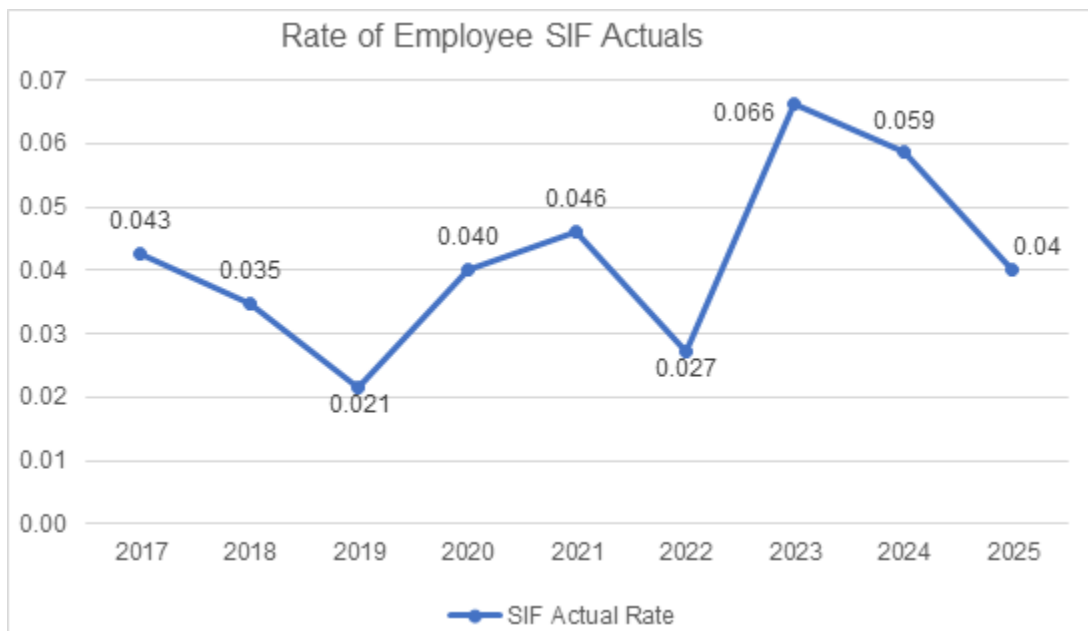
10 **1. Historical Data (2017-2025)**

11 PG&E includes historical data in the Employee SIF Actual SOM data file
 12 for the years 2017 through 2025¹¹ in this report, which is consistent with the
 13 implementation of PG&E’s SIF Prevention Program. The dataset includes
 14 injury type, incident date, location, and EEI SIF Criteria classification. There

¹¹ Historical data through 2021 was provided in PG&E’s first SOM report provided on April 1, 2022.

1 are a total of 99¹² employee SIF Actuals that met the EEI SIF Criteria. Out
2 of the 99 employee SIF Actuals, 6 resulted in fatalities and 93 resulted in
3 serious injuries. Out of the 93 serious injuries, fifty-eight percent (54 of 93)
4 met the criteria of bone fracture, including the hands, feet, ankle, and legs.
5 Of the 6 fatalities, one involved a violent act of a third party, three involved
6 operations of motor vehicles, one involved a pipeline drying (pigging) line of
7 fire incident, and one involved a tire changing incident. The last fatality
8 involving an employee occurred on January 31, 2023. The SOM Employee
9 SIF Actual historical rate is shown in Figure 1.1-2 below.

**FIGURE 1.1-2
RATE OF SOMS SIF ACTUAL (EMPLOYEE)
HISTORICAL PERFORMANCE**



2. Data Collection Methodology

Injury data are collected by the Nurse Care Line (NCL), an enhanced injury reporting process for reporting major and minor work-related injuries. Employees receive medical advice, self-care information, and clinic referrals from the NCL. Injuries are then entered into PG&E's Safety and

¹² Employee SIF Actual count updated to include two incidents (August 2021 and December 2023) not in the April 1, 2025, filing. Employee labor hours also revised from 4,393,539 to 4,551,618 (December 2021).

1 Environmental Management System (SEMS) database, which houses all
2 employee injury data.

3 As mentioned above, the SIF-A (Employee) SOM as defined in
4 D.21-11-009 is applied to PG&E's injury and SIF dataset, and 2022 was the
5 first year in which the data were analyzed and reported under this definition.
6 To evaluate and establish historical performance for the SIF-A (Employee)
7 SOM metric, PG&E reviewed all employee injury data from 2017 through
8 2021 to determine if any met one of the 14¹³ EEI SIF Criteria as
9 summarized in Section A.2. above. To establish historical performance for
10 the first SOMs report submittal, PG&E reviewed approximately 18,000-line
11 items of injury data. A substantial portion of those were not OSHA
12 recordable (i.e., first aid, non-OSHA recordable) and were removed from the
13 population. The remaining population that met the OSHA definition (i.e.,
14 work-related injury) was reviewed against the EEI SIF Criteria for this report.

15 3. Metric Performance for the Reporting Period

16 Figure 1.1-2 illustrates the rate of employee serious injuries from
17 January 1, 2025, through December 31, 2025. In 2025, there were 12
18 employee serious injuries, and 75 percent of the employee serious injuries
19 were due to bone fractures (9 of 12), including bone fractures of the ankle,
20 elbow, foot, back, leg, ribs, and wrist.

21 The 2025 SIF rate of 0.04¹⁴ is a decrease from the 2024 rate of 0.059.
22 PG&E's current and planned work activities for improving the long-term
23 performance of this metric are discussed in Section E below.

24 C. (1.1) 1-Year Target and 5-Year Target

25 1. Updates to 1- and 5-Year Targets Since Last Report

26 There were no changes to the 1-year and 5-year targets since the
27 September 2025 SOMs report filing. The 2025 target for rate of SIF-A
28 (Employee) is to remain in the 1st quartile of the total company industry

13 The EEI SIF Criteria included a list of 14 during the 2017 – 2024 injury data review. The list was updated to 15 in 2025 (updated EEI SIF Criteria referenced in Section A.2).

14 At the beginning of 2025, the rates were updated from three to two decimal places. Rates for prior years remain unchanged and continue to be reported to three decimal places.

1 benchmarking average (see Figure 1.1-3 below). PG&E's 2025 threshold of
2 0.06 considered EEI benchmarking data using the EEI SIF Criteria.

3 **2. Target Methodology**

4 To establish the 1-year and 5-year target thresholds, PG&E considered
5 the following factors:

- 6 • Historical Data and Trends: PG&E pulled OSHA recorded injuries from
7 2017 to 2021 to review each injury against the EEI SIF Criteria. This
8 injury dataset was used because it aligns with the beginning of the
9 PG&E SIF Prevention Program (est. in 2017). Over that historical data
10 period, performance showed a consistent trend at or around 0.040 injury
11 rate, with a dip in 2019 and trend back up in 2020 and 2021. A similar
12 pattern occurred for the years 2022 and 2023 with a dip in rate and then
13 an increase, but still below the 2023 threshold target rate of 0.070. For
14 2024, PG&E's 2024 target threshold for the employee SIF Actual was
15 0.060 which represents a 0.010 target decrease comparable with PG&E
16 internal benchmarking practices. PG&E improved injury severity in 2024
17 (including zero fatalities). [The SIF-A rate increased in 2024 supporting
18 the decision not to lower the target for 2025. In 2025, the rate
19 decreased from 0.06 to 0.04, a result of the SIF Prevention Program
20 described in Section E below. \(See Figure 1-1.2\)](#)
- 21 • Benchmarking: Since 2022, PG&E has used benchmarking data from
22 EEI for comparison with PG&E's performance. [PG&E's performance for
23 2025 is first-quartile.](#)
- 24 • Regulatory Requirements: None
- 25 • Attainable Within Known Resources/Work Plan: Yes. We are focusing
26 on high-energy hazard identification and implementation of essential
27 controls to build the capacity to fail safely.
- 28 • Appropriate/Sustainable Indicators: While the performance at or below
29 the target threshold is sustainable, the more appropriate metric is to
30 focus on injuries resulting from a high-energy incident, which is
31 consistent with both industry SIF-A monitoring and the SPM.
- 32 • Other Qualitative Considerations: This target threshold approach was
33 established to account for all job-related tasks with the potential to
34 cause injury as defined by the EEI SIF Criteria.

1 **3. 2026 and 2030 Target**

2 The target for 2026 and 2030 is 0.05 based on EEI benchmarking data,
3 current and historical PG&E performance, and the 3-year average of
4 performance in 1.1. See Historical Data and Trends above for details.

5 **D. (1.1) Performance Against Target**

6 **1. Progress Towards the 1-Year Target**

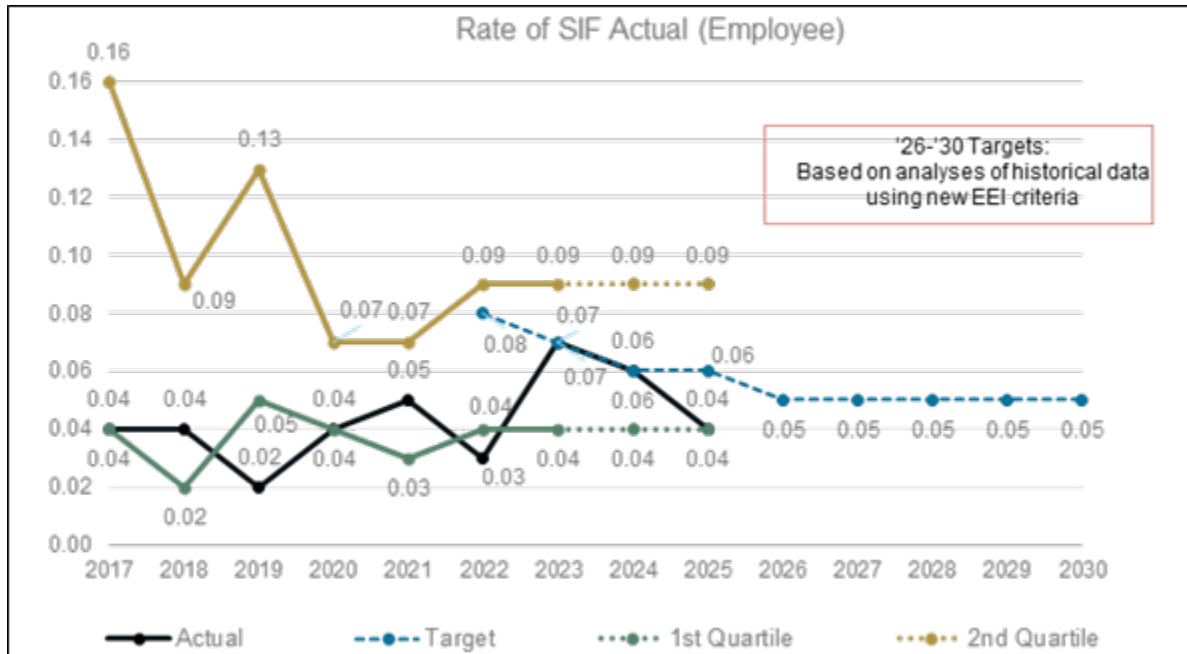
7 As demonstrated in Figure 1.1-3 below, in 2025, the Employee SIF
8 Actual rate of 0.04 was a decrease compared to 2024. The employee
9 serious injuries contributing to this rate are related to falls > 4 ft (6 bone
10 fractures), slips, trips, and falls (2 bone fractures, 2 herniated disks), motor
11 vehicle incident (1 bone fracture), and a third-party assault (1 head trauma).
12 As part of PG&E's implementation of the SIF Capacity and Learning
13 model¹⁵ described in Section E, SIF investigations—encompassing cause
14 evaluations and any necessary corrective actions—have been completed or
15 are underway for these incidents.

16 **2. Progress Towards the 5-Year Target**

17 As discussed in Section E below, and in consideration of the trend,
18 PG&E continues to deploy several programs to improve the long-term
19 performance of this metric and to meet the Company's 5-year performance
20 target.

¹⁵ PG&E's SIF Capacity and Learning model incorporates the use of the EEI Safety Classification and Learning (SCL) model methodology for classifying incidents along with building the capacity to safely recover for a complete SIF Prevention Program.

**FIGURE 1.1-2
RATE OF SOMS SIF ACTUAL (EMPLOYEE)
HISTORICAL PERFORMANCE AND TARGETS**



E. (1.1) Current and Planned Work Activities

PG&E’s SIF Prevention Program: PG&E’s SIF Prevention Program focuses on identifying high-energy and implementing essential controls to prevent serious injuries and fatalities. All injuries are investigated and evaluated to determine if essential controls were present. The Functional Areas (FA) teams conduct in-depth cause evaluations for all incidents classified as SIF-A or SIF-P. The results of these investigations are monitored through the Corrective Action Program notification process, created for each event as PG&E develops corrective actions to reduce the likelihood of recurrence. All injuries and reported near hits are evaluated to determine the high-energy hazards.

PG&E’s SIF Capacity & Learning (PG&E SCL) Model: Advances how we understand, manage, and prevent serious injuries and fatalities. PG&E’s SCL model defines safety as the presence of controls for high-energy hazards to assess whether employees have the capacity to fail safely. Over 24,000 frontline employees and contractors have been trained to identify high-energy hazards and to implement Essential Controls to enable employees and contractors to fail safely. In 2025, controls were in place during 92 percent of high-energy work activities measured by post-incident analysis and

1 High- Energy Control Assessments (HECAs). PG&E learns from high-energy
2 incidents by performing causal evaluations.

3 Human Performance (HU) Tools: PG&E continues to teach and roll out the
4 10 Human Performance Tools that were identified as being fundamental to
5 preventing human error. The HU Tools are deeply connected to the SIF
6 Prevention Program. The FAs have matured in this space as they have
7 engagement/training sessions held by their own employees or members of the
8 PG&E Academy. When used and understood, HU tools slow us down, remove
9 the risk of complacency, and help us conduct our work safely.

10 PG&E's Safety Excellence Management System (PSEMS): PSEMS is the
11 framework for how we systematically manage our processes, assets, and
12 employee and contractor safety to prevent injury and illness. Consisting of
13 13 elements, it establishes governance and operational requirements for how
14 PG&E operates its business to generate and deliver safe, reliable, affordable,
15 and clean energy for our customers and hometowns. PSEMS is part of PG&E's
16 Performance Playbook along with Breakthrough Thinking and the Lean
17 Operating Model.

18 PSEMS follows the Plan, Do, Check, Act cycle of continuous improvement,
19 ensuring processes are evaluated, coursed, and measured annually. In 2025,
20 [Element 5: Operational Control was a key focus, as it is integrated with the](#)
21 [PG&E SIF Capacity & Learning Model and operationalized through high-energy](#)
22 [control assessments and Energy-Based Observations that identify and verify](#)
23 [controls for high-energy hazards are in place](#). An Assurance team was
24 established in 2025, aligned with Element 13: Assurance, which is tasked with
25 validating the effectiveness of the essential controls. These integrations
26 strengthen PG&E's safety culture and reinforce the company's commitment to
27 continuous improvement through measurable performance and reduced risk
28 exposure.

29 Regional Safety Directors: PG&E's team includes a field safety organization
30 led by five Regional Safety Directors who partner with the FAs¹⁶ to advise on
31 and facilitate health and safety program implementation. This includes
32 delivering safety programs to improve safety culture, energy-based observations

16 PG&E changed its title from Lines of Business to FAs in 2022.

1 and hazard identification, and the evaluation of essential controls for providing
2 co-workers with the ability or capacity to fail safely from a high-energy incident
3 without life-threatening or life- altering injury. This team supports incident
4 investigations, training, tailboards, and emergency response.

5 Injury Management: The SIF-A (Employee) SOM definition includes injuries
6 that occur during any work activity (including low or no energy tasks such as
7 lifting, walking, managing tools like knives), which is broader than the focus on
8 high-energy incidents [included in the SIF Prevention Program](#). Therefore, a
9 significant driver for improvement is within our occupational health organization
10 where OSHA and Days Away Restricted Transferred (DART) cases are
11 managed. DART cases are employee OSHA-recordable injuries that involve
12 days away from work and/or days on restricted duty or a job transfer because
13 the employee is no longer able to perform his or her regular job. The workforce
14 is supported in the expansion of PG&E's ergonomic programs and an increased
15 number of Industrial Athlete Specialists for job site evaluations. The primary
16 goal of these efforts is to reduce injury severity through injury prevention and
17 early intervention care.

18 Safety Leadership Development in the Field: [PG&E's Frontline Safety
19 Leadership Program provides training for frontline crew leaders so they have the
20 necessary safety skills to create trust, set expectations, remove barriers to
21 safety and identify and mitigate at risk behaviors.](#)

22 Safety Observation Program: Safety Observations play a critical role in
23 reducing employee and contractor injuries and fatalities by increasing
24 awareness of high-energy hazards where Essential Controls are or are not
25 present, reinforcing positive work practices, and driving PG&E's Speak-Up
26 culture. PG&E performs Energy Based Observations and High-Energy Control
27 Assessments, which measure the presence of essential controls for high-energy
28 work activities. [The SafetyNet observation tool was used prior to September 1,
29 2025, and the Mirata observation tool has been used since September 1, 2025,
30 and includes a dashboard to communicate the results of the observations. In
31 2025, approximately 103,000 employee and contractor safety observations were
32 conducted in SafetyNet, and 56,000 were conducted in Mirata. When essential
33 controls are not in place, this is communicated to the respective FAs.](#)

1 Transportation Safety: PG&E's Transportation Safety Programs ensure
2 compliance with federal DOT and California regulatory requirements while
3 reducing motor vehicle incidents that could result in serious injuries or fatalities
4 to employees and the public.

5 Driver performance data is used to identify specific risk drivers for targeted
6 intervention, including driver training, driver action plans and implementing
7 vehicle safety technology

8 PG&E continues to use the Driver Scorecard, which applies a point-based
9 system to assess performance and triggers higher-level review within the FA
10 and under the Safe Driving Behavior policy.

11 In 2025, 1165 Action Plans were initiated and 1135 were completed with the
12 30 remaining currently in progress. Smith Driving courses continue to be
13 initiated for apprentices and new hires including behind-the-wheel and close
14 quarter maneuvering courses.

15 Approximately 10 percent of the owned fleet (1,016 trouble trucks) have
16 installed Brigade 360-Camera Systems with an audible backing sensor and rear
17 distance display. New trouble truck specifications include the 360-camera
18 system technology and the trucks are delivered with the cameras pre-installed.
19 The four high-mounted external cameras eliminate blind spots with an in-cab HD
20 display of front, back and both vehicle sides providing the driver improved
21 visibility to see everything in the vehicle's path.

22 In 2025, PG&E completed the retrofit of all 656 gas service and electric
23 meter trucks with backup sensor technology featuring in-cab audible alerts and
24 rear distance display. The backup sensors alert the driver of objects in the
25 vehicle's blind spot while backing to enhance safety. New gas service and
26 electric meter truck specifications include the backup sensor technology, and the
27 trucks are delivered with the sensors installed.

28 PG&E's motor vehicle safety performance through 2025 was in the top
29 decile, which has been enabled by motor vehicle technology, addition of
30 controls, and continued driver training for apprentices and new hires.

31 PG&E's continued focus on eliminating SIF incidents has resulted in
32 measurable progress, with improvement in 2025 compared to 2024, due in part
33 to continued cross-functional collaboration.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 1.2
RATE OF SIF ACTUAL
(CONTRACTOR)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 1.2**
4 **RATE OF SIF ACTUAL**
5 **(CONTRACTOR)**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (1.2) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metric (SOM) 1.2 – Rate of Serious Injury and/or
11 Fatality (SIF) Actual (Contractor) is defined as:

12 *Rate of SIF Actual (Contractor) is calculated using the formula: Number*
13 *of SIF-Actual cases among contractors x 200,000/contractor hours worked,*
14 *where SIF-Actual is counted using the methodology developed by the*
15 *Edison Electrical Institute’s (EEI) Occupational Safety and Health*
16 *Committee (OS&HC).*

17 **2. Introduction of Metric**

18 Pacific Gas and Electric Company’s (PG&E or the Company) safety
19 stand is “Everyone and Everything is Always Safe.” *This includes our*
20 *employee and contractor workforce, as well as the public. We remain*
21 *committed to building an organization where every work activity is designed*
22 *to facilitate safe working conditions and every member of our workforce is*
23 *encouraged to speak up if they see an unsafe or risky condition with the*
24 *confidence that their concerns and ideas will be addressed.* As part of this
25 stand, PG&E is committed to contractor safety.

26 As defined in Decision (D.) 21-11-009, the SIF Actual (Contractor) SOM
27 calculation is applied to PG&E’s existing work- related injury and SIF
28 datasets. The data were analyzed and reported under this definition
29 beginning with the first report which was submitted in March of 2022.

30 The EEI OS&HC has oversight over the SIF Criteria, which are reviewed
31 annually and updated based on additional learnings from injury classification
32 to provide further clarification or criteria for the following year.

1 The EEI SIF Criteria were revised and published August 1, 2024, and
2 became effective January 1, 2025.¹ The criteria are included in Appendix 9
3 of the EEI Safety Classification and Learning (SCL) Model guidance.² The
4 SIF Criteria include the following definitions:

- 5 • **Life-Threatening:** A physical injury that if not immediately addressed is
6 likely to lead to the death of the affected individual and will usually
7 require the intervention of life sustaining support by external emergency
8 response personnel or colleagues.
- 9 • **Life-Altering:** A physical injury that results in permanent loss of use of
10 an internal organ, body function, or body part.

11 The SIF Criteria includes these serious injury types:

- 12 1) Fatalities;
- 13 2) Amputations (involving bone), excludes distal phalanx **unless thumb,**
14 **index, or great toe;**
- 15 3) Head trauma that results in a traumatic brain injury, intracranial
16 bleeding, or loss of consciousness for greater than 30 minutes;
- 17 4) Injury or trauma to vital organs to include brain, spinal cord, heart, lungs,
18 kidneys, liver, spleen, large and small intestine, and stomach;
- 19 5) Bone fractures requiring surgery for repair (pins, rods, screw, plates,
20 wires, etc.) excludes fingers and toes;
- 21 6) Acute traumatic herniated disc with neurologic deficit – sensory or
22 motor;
- 23 7) 2nd degree burn (10 percent body surface); -3rd degree burn (5 percent
24 of body surface); or 3rd degree burn requiring skin graft;
- 25 8) Eye injuries resulting in permanent vision loss or change in vision;
- 26 9) High pressure injection injuries requiring surgical debridement and
27 irrigation;
- 28 10) **Medically diagnosed** Heat Stroke;
- 29 11) Dislocation of the hip, elbow, or knee **does not include dislocation of the**
30 **patella (kneecap);**
- 31 12) Electrical contact injuries;

1 [EEI Serious Injury and Fatality \(SIF\) Criteria.](#)

2 EEI SCL model guidance. EEI SIF Criteria are in Appendix 9 of the [SCL model report.](#)

- 1 13) Vascular trauma requiring surgery;
2 14) Acute chemical or radiological exposure resulting in injury to vital organs
3 to include brain, spinal cord, heart, lungs, kidneys, liver, spleen, large
4 and small intestine, and stomach; and
5 15) Other: Injuries classified as 'other' must meet the life-threatening or
6 life-altering definition.

7 PG&E's SIF Prevention Program was deployed in 2016 to establish a
8 cause evaluation process for employee and contractor serious safety
9 incidents. This program was established to create consistency and
10 guidance in classifying and evaluating serious safety incidents for all
11 contractors with the goal of reducing the number and severity of safety
12 incidents that result in a SIF. The program's objective is to learn from safety
13 incidents by performing cause evaluations on each SIF Actual (SIF-A) and
14 SIF Potential (SIF-P) incident, implement corrective actions, and share key
15 findings and learnings across the enterprise. PG&E only investigated
16 contractor incidents resulting in a SIF-A (fatality or serious injury that was
17 defined as life threatening or life altering) and then entered the results into
18 the Corrective Action Program (CAP). Contractors investigated all other
19 incidents and reported back to PG&E, but those incidents were not entered
20 into CAP.

21 From 2017 to 2020, PG&E classified SIF-A incidents based on the job
22 task and whether a life altering or life-threatening injury or fatality occurred.
23 In August of 2020, PG&E adopted EEI's SCL³ model to classify its SIF
24 incidents (See Figure 1-2.1). The EEI SCL model classifies incidents into
25 seven categories: High-Energy SIF (HSIF),⁴ Low-Energy SIF (LSIF),⁵

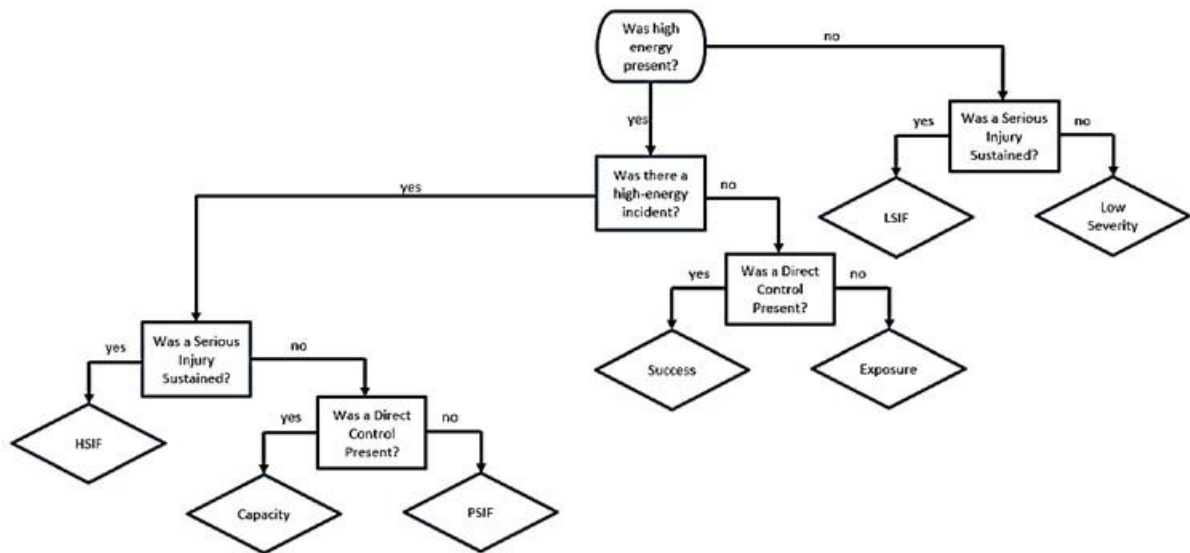
3 EEI SCL Model available here: <https://www.safetyfunction.com/scl-model>.

4 *Id.* at p. 19, HSIF is defined as: "Incident with a release of high-energy in the absence of a direct control where a serious injury is sustained."

5 *Id.* at p. 19, LSIF is defined as: "Incident with a release of low energy in the absence of a direct control where a serious injury is sustained."

1 Potential SIF (PSIF),⁶ Capacity,⁷ Exposure,⁸ Success,⁹ and Low
 2 Severity.¹⁰

**FIGURE 1.2-1
 EEI SCL MODEL FLOWCHART**



3 Adopting the EEI SCL model has improved the SIF Program by bringing
 4 a consistent and objective approach to review and classify SIF incidents
 5 across the Company and industry. The EEI SCL model allows the Company
 6 to focus its safety and risk mitigation efforts on the most serious outcomes
 7 and highest risk work where a high-energy is present or a high-energy
 8 incident occurred. In June of 2020 PG&E modified the SIF Program to
 9 include internal classification and investigation of contractor SIF-P

⁶ *Id.* at p. 19, PSIF is defined as: “Incident with a release of high-energy in the absence of a direct control where a serious injury is not sustained.”

⁷ *Id.* at p. 19, Capacity is defined as: “Incident with a release of high-energy in the presence of a direct control where a serious injury is not sustained.”

⁸ *Id.* at p. 19, Exposure is defined as: “Condition where high-energy is present in the absence of a direct control.”

⁹ *Id.* at p. 19, Success is defined as: “Condition where a high-energy incident does not occur because of the presence of a direct control.”

¹⁰ *Id.* at p. 19, Low Severity is defined as: “Incident with a release of low energy where no serious injury is sustained.”

1 incidents.¹¹ This expanded requirement led to an increase in contractor
2 injury data. [The EEI SCL model is also used for the Contractor SIF-A Safety](#)
3 [Performance Metric \(SPM\) and is aligned with other California utilities.](#)

4 **B. (1.2) Metric Performance**

5 **1. Historical Data (2017-2025)**

6 PG&E includes historical data for the years 2017 through 2025 in this
7 report. This timeframe is consistent with the implementation of PG&E's SIF
8 Prevention Program. The dataset includes injury type, incident date,
9 location, and EEI SIF Criteria classification. See the corresponding
10 Contractor SIF-A SOM data file for a list of incidents. Following the Kern
11 Order Instituting Investigation (OII) Settlement Agreement (SA),¹² PG&E
12 deployed the SIF Prevention Program to investigate employee and
13 contractor incidents resulting in life altering, life threatening, or fatal injuries.
14 Beginning in 2017, PG&E only tracked contractor incidents that were
15 classified through the SIF Prevention Program¹³ meeting those criteria.
16 Prior to the implementation of the Kern OII requirements, contractors were
17 not required to report SIF incidents. In June 2020, PG&E expanded the SIF
18 Prevention Program to include investigating contractor incidents rising to
19 SIF-P classification (focusing on incidents that meet the EEI SCL model as
20 described above). This increased the number and types of injuries and
21 incidents that contractors are required to report¹⁴ compared to prior
22 years.¹⁵ For 2020 through 2025 the dataset reflects the expanded SIF-P
23 incident reporting requirements for contractors implemented in June of

¹¹ SAFE-1100S-B001 bulletin previously noted was retired. References now include GOV-6102S, "Enterprise Cause Evaluation Standard", and SAFE-1100S, "Serious Injury and Fatality (SIF) Standard."

¹² Investigation 14-08-022, Kern OII (Aug. 28, 2014) SA with California Public Utilities Commission (CPUC) see D.15-07-014.

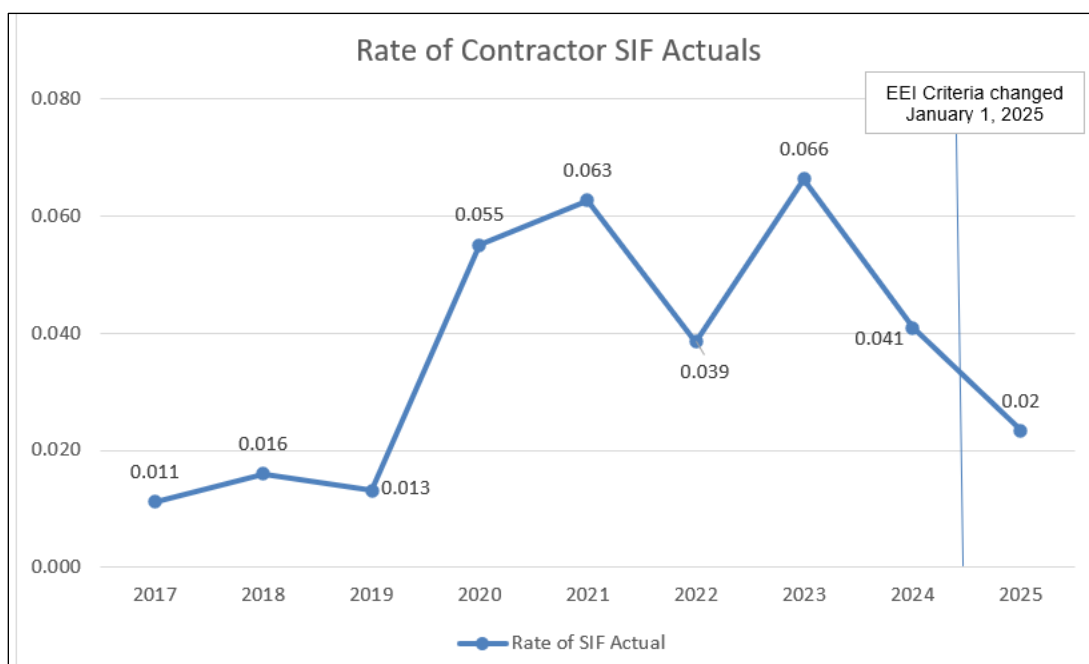
¹³ SAFE-1100S Rev. 08 (2025) SIF Standard.

¹⁴ SAFE-1100S-B001 bulletin previously noted was retired. Reference includes GOV-6102S, "Enterprise Cause Evaluation Standard."

¹⁵ Note, the expanded incident reporting requirement implemented in 2020 does not include the broader SOM SIF-A (Contractor) EEI SIF Criteria metric definition.

1 2020.¹⁶ From 2017 through 2025 there are a total of 86¹⁷ contractor SIF
 2 Actuals that met the EEI SIF Criteria. Out of the 86 contractor SIF Actuals,
 3 13 incidents resulted in 15 fatalities. The remaining 73 incidents resulted in
 4 serious injuries. Of the 15 fatalities, one helicopter crash in 2020 claimed
 5 the lives of three individuals; the other fatalities involved an act of a third
 6 party, falls from trees, electrical pole, gas pipe placement, and operations of
 7 motor and powered vehicles. In September 2025, a PG&E contractor was
 8 fatally injured while performing trench work when high winds caused a tree
 9 to break, fall, and strike the contractor. [The SOM Contractor SIF Actual](#)
 10 [historical rate is shown in Figure 1.2-2 below.](#)

**FIGURE 1.2-2
 RATE OF SOMS SIF ACTUAL (CONTRACTOR)
 HISTORICAL PERFORMANCE**



Note: Following 2023 labor hour adjustment, Figure 1.2-2 reflects the revised rate, corrected from 0.063 to 0.066.

¹⁶ SAFE-1100S, “Serious Injury and Fatality (SIF) Standard”.

¹⁷ The total contractor SIF Actual count of 82 includes one incident resulting in 3 fatalities. While 80 incidents occurred, the three fatalities in a single incident bring the count to 82.

1 **2. Data Collection Methodology**

2 Contractor-related Serious Safety Incidents¹⁸ are reported to the Safety
3 Incident Notification Line Option 1 and then entered into the Enterprise CAP
4 program for SIF review and classification.¹⁹ PG&E’s SIF Program²⁰ is
5 managed through the CAP.

6 As mentioned above, the SIF-A (Contractor) SOM as defined in
7 D.21-11-009 SOM calculation is applied to PG&E’s existing injury and SIF
8 dataset, and 2022 was the first year in which the data were analyzed and
9 reported under this definition. To evaluate and establish historical
10 performance for the SOM SIF-A (Contractor) metric, PG&E pulled data from
11 the CAP system and reviewed 472 issues with the issue type of Contractor
12 Safety. The list included both incidents or injuries reported to PG&E or
13 entered in CAP from 2017 through 2021. Twenty-seven percent, or
14 128 incidents, were related to gas dig-in by a third-party where no injuries
15 occurred. The remaining issues were reviewed to determine if any met the
16 14 EEI SIF Criteria as summarized in Section A.2. above. For the years
17 2022 through 2025, the same process was used to review Contractor Safety
18 related CAPs entered on a monthly basis. A total of 368 contractor related
19 CAPs were reviewed in 2022, 343 were reviewed for 2023, 742 reviewed in
20 2024, and 485 were reviewed in 2025.

21 **3. Metric Performance for the Reporting Period**

22 Figure 1.2-2 illustrates the rate of contractor serious injuries from
23 January 1, 2025, through December 31, 2025. The 2025 SIF rate of 0.02²¹
24 reflects a decrease from the 2024 year-end rate of 0.041 and is lower than
25 the target rate of 0.10.

18 As defined by SAFE-1004S: Safety Incident Notification and Response Management.

19 SAFE-1100S-B001 bulletin previously noted was retired. Now reference GOV-6102S, “Enterprise Cause Evaluation Standard.” PG&E contractors are required to submit any Serious Safety Incidents or PSIF incidents to PG&E within 5-business days of becoming aware of the incident.

20 SAFE-1100S: SIF Standard determined SIF classification and management.

21 Since the beginning of 2025, the rates were updated from 3 to 2 decimal places. The prior years were left unchanged with the rates at 3 decimal places.

1 For 2025, six contractor serious injuries met the EEI SIF Criteria. PG&E
2 experienced a contractor fatality in September 2025, which was described in
3 the historical data section.

4 PG&E's current and planned work activities for improving the long-term
5 performance of this metric are discussed in Section E below. Performance
6 through 2025 against target is further discussed in Section D.1 below.

7 C. (1.2) 1-Year Target and 5-Year Target

8 1. Updates to 1- and 5-Year Targets Since Last Report

9 There were no changes to the 1- and 5-year targets since the
10 September 2025 SOMs report filing. As mentioned above, the rate of
11 Contractor SIF-A dataset includes the expanded SIF-P incident reporting
12 requirements for contractors implemented in June of 2020. Additionally, as
13 was identified and closed out as part of the front-end processors audit, the
14 process to gather and validate accurate contractor hours has improved, and
15 PG&E is working to ensure continued data fidelity prior to updating targets.
16 We will continue to monitor Contractor SIF-A trends and adjust the targets
17 once the dataset has matured, including internal targets that are driving
18 improved performance. We are establishing a baseline on the new criteria
19 before adjusting targets. PG&E has internal targets that are more restrictive
20 than these targets and are being used to drive SIF performance.

21 2. Target Methodology

22 To establish the 1-year and 5-year target thresholds, PG&E considered
23 the following factors:

- 24 • Historical Data and Trends: The target threshold takes into
25 consideration the historical increase (from 0.013 to 0.063) between
26 2019, 2020 and 2021, after expanding the contractor reporting
27 requirements in 2020. This increased the amount and rate of contractor
28 serious injuries (as defined by the EEI SIF Criteria) by over 466 percent.
29 It also takes into consideration that in 2022 PG&E expanded contractor
30 injury reporting requirements to meet the EEI SIF Criteria;
- 31 • Benchmarking: Not available for the new EEI SIF Criteria effective
32 January 1, 2025. PG&E confirmed that EEI is collecting these data
33 among its utility members and hopes to increase benchmarking

1 capability as more utilities begin to track contractor incident data. For
2 establishing the SOM 1.2: SIF-A (Contractor) target threshold PG&E
3 used the industry data that were available.

- 4 • Regulatory Requirements: None;
- 5 • Attainable Within Known Resources/Work Plan: Yes. The main focus
6 for driving down injuries is noted below in planned/future work related to
7 Contractor Safety initiatives, [which includes the focus on high-energy](#)
8 [hazard identification and implementation of essential controls to build](#)
9 [the capacity to fail safely](#);
- 10 • Appropriate/Sustainable Indicators: While performance at or below the
11 target may be sustainable, the more appropriate metric is to focus on
12 injuries resulting from a high-energy incident, which is consistent with
13 both industry SIF-A monitoring and the SPM; and
- 14 • Other Qualitative Considerations: This target approach was established
15 to account for all job-related tasks with the potential to cause injury as
16 defined by the EEI SIF Criteria.

17 **3. 2026 and 2030 Targets**

18 [The 2026 \(1-year\) target is 0.06 and 2030 \(5-year\) target is 0.06.](#) These
19 targets take into consideration the historical increase (from 0.013 to 0.063)
20 from 2019 through 2021 after expanding the contractor reporting
21 requirements in 2020. It also considers that in 2022 PG&E expanded
22 contractor injury reporting requirements to meet the SOM SIF-A (Contractor)
23 as defined by the EEI SIF Criteria and that the rates are subject to change
24 depending on the number of contractors hours worked.

25 **D. (1.2) Performance Against Target**

26 **1. Progress on Sustaining the 1-Year Target**

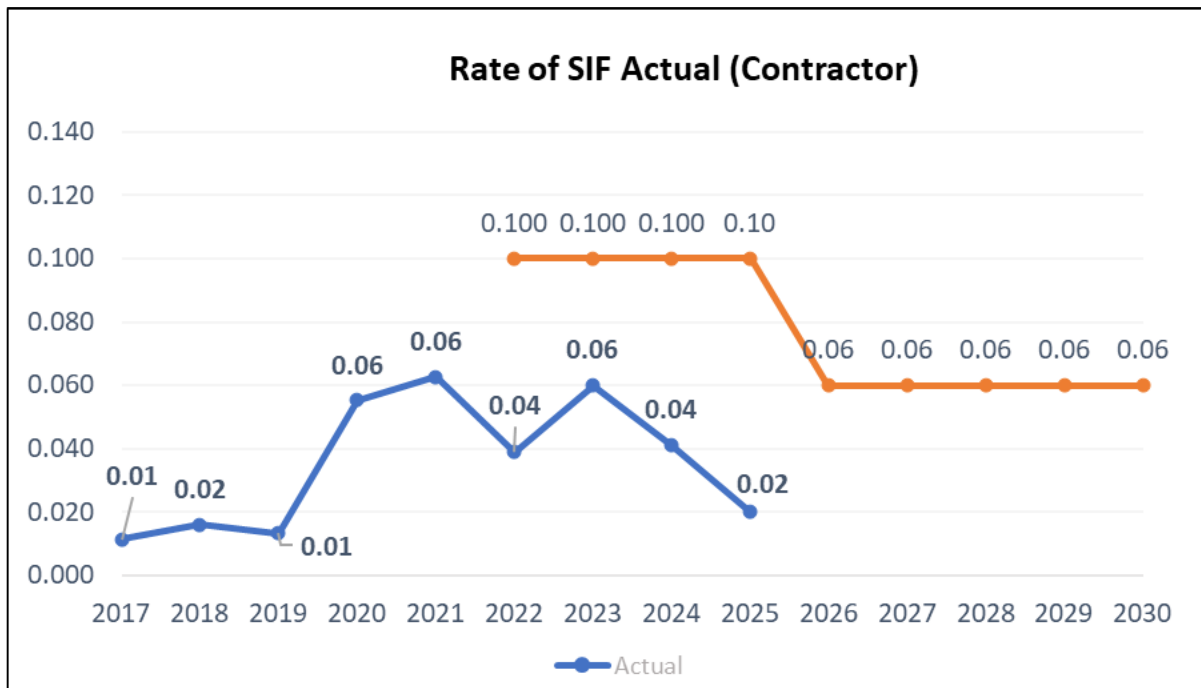
27 [In 2025, \(see Figure 1.2-2\), the Contractor SIF Actual rate of 0.02 was a](#)
28 [decrease compared to 2024. This rate is reflective of the contractor fatality](#)
29 [that occurred in September 2025.](#) SIF investigations have been completed
30 or are underway for the incidents including corrective actions and we are

1 continuing to monitor the trend. In addition, PG&E implemented the SIF
2 Capacity and Learning Model²² as described in section E.

3 **2. Progress on Sustaining the 5-Year Target**

4 PG&E continues to deploy several programs to improve the long-term
5 performance of this metric and to meet the 5-year performance target.

FIGURE 1.2-3
RATE OF SOMS SIF ACTUAL (CONTRACTOR)
HISTORICAL PERFORMANCE AND TARGETS



6 **E. (1.2) Current and Planned Work Activities**

- 7 • PG&E’s SIF Prevention Program: Please see Section E (1.1) Current and
8 Planned Work Activities in PG&E SOMs Report Chapter 1.1.
- 9 • PG&E’s SIF Capacity and Learning Model: [Please see Section E \(1.1\)](#)
10 [Current and Planned Work Activities in PG&E SOMs Report Chapter 1.1.](#)
- 11 • Human Performance (HU) Tools: [Please see Section E \(1.1\) Current and](#)
12 [Planned Work Activities in PG&E SOMs Report Chapter 1.1.](#)

²² PG&E’s SIF Capacity and Learning model incorporates the use of the EEI SCL model methodology for classifying incidents, along with building the capacity to safely recover for a complete SIF Prevention Program.

- 1 • [PG&E's Safety Excellence Management System \(PSEMS\)](#): Please see
2 Section E (1.1) Current and Planned Work Activities in PG&E SOMs Report
3 Chapter 1.1 with further emphasis on PSEMS Element 9: Contracted
4 Services and Purchased Goods relating to contractor safety.
- 5 • [Contractor Safety Quality Assurance Reviews \(CSQAR\)](#): CSQARS are
6 conducted on Contractors with adverse trends in safety performance and
7 who are at risk of experiencing a Serious Injury or Fatality. These are also
8 conducted for all new contractors when they begin performing work on behalf
9 of PG&E and for all contractors on a triennial basis, regardless of
10 performance. PG&E utilizes its third-party administrator, ISNetwork (ISN), to
11 facilitate these CSQARs. The purpose is to partner directly with our contract
12 partners, perform a comprehensive review of their safety programs and
13 culture, and implement controls to eliminate serious injuries and fatalities.
14 The contractors participate in a 6-week examination of their safety culture
15 within their company where opportunities are identified, a barrier analysis is
16 conducted, and corrective actions are implemented. Following the successful
17 completion of the initial six weeks, [action items are assigned with specified
18 timeframes for mitigation](#). PG&E checks in with contractors to ensure the
19 corrective actions were implemented as designed, were effective and
20 self-sustaining, and do not expose employees to unforeseen hazards. [In
21 2025, 551 CSQARs were completed](#).

22 In April 2025, PG&E enhanced the CSQAR process by including
23 CultureSight® through Monarch, a consulting arm of ISN. The process is
24 now called Review and Verification Services 360™ (RAVs360).
25 CultureSight® is a data-driven safety culture assessment tool functioning as
26 an anonymous electronic survey designed to capture contractors'
27 perceptions of PG&E culture. Feedback is gathered on critical safety-culture
28 dimensions like leadership alignment, risk awareness, communication, and
29 continuous improvement and then analyzed and benchmarked against peer
30 utilities to highlight strengths, opportunities, and potential risks. [The insights
31 gathered are shared enterprise-wide in partnership with the contractor](#).

- 32 • [PG&E's Contractor Safety Program](#): Beginning in 2016, PG&E implemented
33 a formal Contractor Safety Program to help contractor partners reduce illness
34 and injuries when working with PG&E. The program was implemented as

1 required by the CPUC, Kern Oil SA. PG&E's Contractor Safety Program
2 includes all contractors and subcontractors (currently over 3,000) performing
3 high- and medium-risk work on behalf of PG&E, on PG&E owned, sites and
4 assets. The Contractor Safety Program consists of the following:

- 5 – Contractor Company Pre-Qualification: PG&E leverages ISN to collect
6 performance and safety compliance program information from all prime
7 and subcontractors that conduct work classified as high or medium risk.
8 PG&E is responsible for the performance of its contractors. As part of
9 this effort, ISN, a third-party administrator, independently assesses
10 contractors' historical safety data, safety, drug/alcohol, and written
11 safety programs to evaluate whether contractors meet PG&E's minimum
12 performance standards and have the necessary risk management
13 programs in place to proactively mitigate risk. A variance to work for
14 PG&E is required for contractors who do not meet the prequalification
15 requirements. The variance process includes a review of the
16 contractor's safety performance, an improvement plan, and the business
17 need in relation to the proposed scope of work. The decision to award a
18 variance requires Functional Area (FA) Senior Vice President (VP),
19 VP of Sourcing, Senior Director of Safety and Chief Safety Officer
20 approval.
- 21 – Enhanced Safety Contract Terms: Following a serious public or worker
22 safety incident, PG&E contract terms require the contractor to conduct a
23 cause evaluation, share the analysis with PG&E, and cooperate and
24 assist with PG&E's cause evaluation analysis, including developing
25 corrective actions for the incident. Under the enhanced Safety Contract
26 Terms, PG&E has the right to:
 - 27 1) Designate safety precautions in addition to those in use or proposed
28 by the contractor;
 - 29 2) Stop Work to ensure compliance with safe work practices and
30 applicable federal, state, and local laws, rules, and regulations;
 - 31 3) Require the contractor to provide additional safeguards beyond what
32 the contractor plans to utilize;
 - 33 4) Terminate the contractor for cause in the event of a serious incident
34 or failure to comply with PG&E's safety precautions;

- 1 5) Review and approve work plan criteria, including safety plans; and
2 6) Require the contractor to promptly, thoroughly, and transparently
3 investigate all safety incidents that occur during Contractor’s PG&E
4 related work in compliance with PG&E’s Enterprise Cause Standard,
5 including all SIF-A and SIF-P incidents, which shall be investigated
6 jointly with PG&E, taking into account the priority and needs of
7 Occupational Safety and Health Administration and other regulator
8 investigations.

- 9 • Contractor Job Safety Planning: Each FA has safety plan requirements for
10 contractors that are unique to its operations. Safety plans must include
11 formal training requirements, job site work controls, specialized equipment to
12 reduce hazards, and personal protective equipment. Prior to starting work,
13 PG&E reviews the adequacy of the safety plans, including contractor safety
14 personnel qualifications where applicable. PG&E performs a safety
15 assessment to evaluate whether additional safety mitigations are required,
16 including whether to assign PG&E onsite safety personnel. These reviews
17 must be conducted by PG&E employees or third-party experts that are
18 qualified to perform such work.
- 19 • Contractor Oversight/Observations: Qualified PG&E personnel oversee
20 contractor work to ensure it follows a PG&E approved safety plan designed
21 for the job. PG&E conducted approximately 120,000 contractor field safety
22 observations during 2025. High-risk findings are reviewed daily, and
23 corrective actions are discussed. Observation data collected by all observers
24 (e.g., PG&E and contractors) are analyzed to support continuous
25 improvement.
- 26 • Contractor Safety Performance Evaluation: FA representatives evaluate
27 contractor safety performance to identify lessons learned and to provide a
28 means of determining future contract award. Prime Contractors must also
29 evaluate all Subcontractors performing any active work during the year either
30 at the conclusion of the contracted work or at least once every calendar year.
31 Safety performance evaluations must include the following minimum
32 performance evaluation criteria:
33 a) Worksite hazard mitigation;
34 b) Training and qualifications compliance;

- 1 c) Work site safety performance (observations);
- 2 d) Safety incident and injury prevention and reporting;
- 3 e) Development and implementation of a PG&E-approved safety plan;
- 4 f) Speak Up and Stop Work Authority; and
- 5 g) Wildfire Prevention and Mitigation.

6 PG&E continues to advance its contractor safety programs aimed at
7 eliminating SIF incidents, which is evident by an improvement of 0.50 for the
8 SIF Actual rate through 2025. PG&E also continues to focus on eliminating
9 SIF incidents has resulted in measurable progress, with improvement in
10 2025 compared to 2024, due in part to continued cross-functional
11 collaboration.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 1.3
SIF ACTUAL
(PUBLIC)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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SIF ACTUAL
(PUBLIC)

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 1.3**
4 **SIF ACTUAL**
5 **(PUBLIC)**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (1.3) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metric (SOM) 1.3 – Serious Injury and Fatality
11 (SIF) Actual (Public) is defined as:

12 *A fatality or personal injury requiring inpatient hospitalization for other*
13 *than medical observations that an authority having jurisdiction has*
14 *determined resulted directly from incorrect operation of equipment, failure or*
15 *malfunction of utility-owned equipment, or failure to comply with any*
16 *California Public Utilities Commission (CPUC or Commission) rule or*
17 *standard. Equipment includes utility or contractor vehicles, and aircraft used*
18 *during the course of business.*

19 **2. Introduction of Metric**

20 Pacific Gas and Electric Company’s (PG&E or the Company) safety
21 stand is “Everyone and Everything is Always Safe.” Our goal is zero public
22 safety incidents resulting from the failure or malfunction of a PG&E asset or
23 from PG&E’s failure to follow rules and/or standards. In support of this,
24 PG&E is continuing to invest in programs that protect the public, including
25 Electric Transmission and distribution system reliability and the reduction of
26 wildfire risk. PG&E remains committed to building an organization where
27 every work activity is designed to facilitate safe performance, every member
28 of our workforce knows and practices safe behaviors, and every individual is
29 encouraged to speak up if they see an unsafe or risky behavior with the
30 confidence that their concerns and ideas will be heard and followed up on.
31 As part of this stand, the Public SIF Actual metric is integral in ensuring the
32 safety of our communities.

1 The Public SIF Actual Metric definition established in Decision
2 (D.) 21-11-009 is a different way for PG&E to categorize and report public
3 safety incidents resulting in a SIF. There are two primary differences
4 between the SOMs Public SIF Actual Metric and the Safety Performance
5 Metric (SPM) Public SIF Metric (SPM Metric 20).

- 6 • First, the SOM requires a finding by “an authority having jurisdiction;”
7 and
- 8 • Second, that finding must determine that the Public SIF Actual:
9 ...resulted directly from incorrect operation of equipment, failure or
10 malfunction of utility owned equipment, or failure to comply with any
11 California Public Utilities Commission (CPUC or Commission) rule
12 or standard.¹

13 As a result, the data in this report represent a subset of the data
14 included in the SPM Report for [Metric 20](#), Public SIF, which is defined as a
15 fatality or personal injury requiring in-patient hospitalization involving utility
16 facilities or equipment. Equipment, in the case of the SPM, includes utility
17 vehicles used during the course of business.

18 In 2012, PG&E improved its data collection processes and reporting for
19 public serious incidents. These data were used to inform PG&E’s Risk
20 Assessment and Mitigation Phase Report, which informs and helps prioritize
21 our investments to address top safety risks. The report outlines our top
22 safety risks and includes descriptions of the controls currently in place, as
23 well as mitigations—both underway and proposed—to reduce each risk.

24 **B. (1.3) Metric Performance**

25 **1. Historical Data (2010 – 2025)**

26 In this report, PG&E is providing 16 years of historical data from 2010
27 through 2025. The graphs included in Figure 1.3-1 and Figure 1.3-2 below
28 show the total number of incidents and the total number of serious injuries or
29 fatalities for each identified incident. [From 2010 through 2025, there were
30 30 confirmed incidents where Public SIF Actuals occurred \(Figure 1.3-1\),
31 which resulted in a total of 176 Public SIFs \(Figure 1.3-2\). There is one
32 incident related to wildfire where a serious injury or fatality to members of](#)

¹ D.21-11-009 – (Rulemaking 20-07-013) Appendix A, p. 2.

1 the public occurred that are shown as “unknown” due to ongoing
2 investigation and/or litigation. The third-party MVI that occurred on March 8,
3 2025, is still pending a SOMs determination due to an on-going investigation
4 The incident that occurred on December 12, 2024, and was received by the
5 Claims Department on July 29, 2025, was removed as hospitalization was
6 unconfirmed.

7 The data include a description of the incident, the type of injury, and
8 identification of the authority with jurisdiction that has determined, or may
9 determine, that incorrect operation, malfunction, or failure to meet a
10 standard was the cause of the SIF. As mentioned above, the data collection
11 and internal reporting processes for public safety serious incidents were
12 improved in 2012. Historical data for the Public SIF Actual Metric are based
13 on this timeframe and also include available data for the years of 2010 and
14 2011.

15 Since the metric definition requires a finding from an authority having
16 jurisdiction, Public SIF Actual incidents in prior years may not appear in the
17 historical data. For the purposes of this report, PG&E is including incidents
18 where PG&E may have disputed the assertion of an authority with
19 jurisdiction that the Public SIF Actual was caused by incorrect operation of
20 utility equipment, a malfunction of utility equipment, or failure to comply to a
21 Commission rule or standard, and/or where the incidents are subject to
22 pending investigation or litigation. These incidents are shown as “unknown
23 or pending” in the corresponding metric data file. PG&E will continue to
24 update the historical data in future SOMs reports as appropriate and identify
25 changes based on new information.

26 **2. Data Collection Methodology**

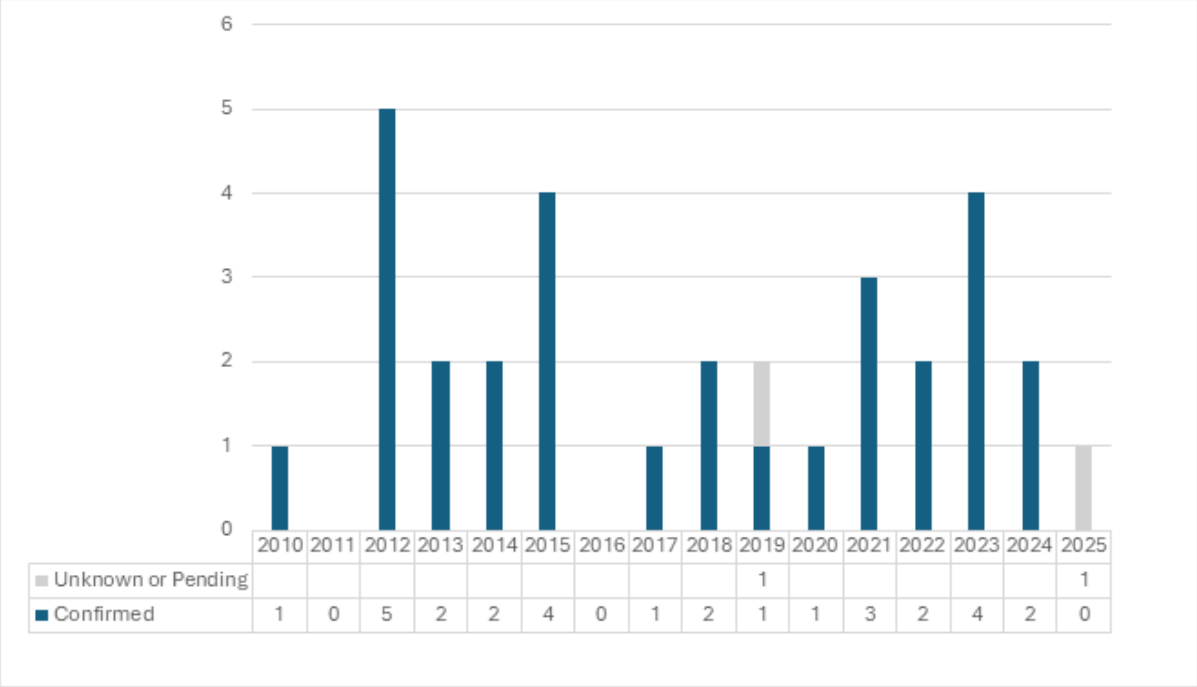
27 PG&E’s Public SIF Actual incident data largely come from the Enterprise
28 Health and Safety Serious Incidents Reports [created in CAP](#), which includes
29 a compilation of Law Department claims from PG&E’s Riskmaster database,
30 Electric Incident Reports, and other reportable incidents such as PG&E
31 Federal Energy Regulatory Commission (FERC) license compliance reports.
32 For the SOMs report, the incidents included in the Public SIF Actual Metric
33 must be determined by an authority having jurisdiction to have resulted
34 directly from: (1) incorrect operation of equipment, (2) failure or malfunction

1 of utility-owned equipment, or (3) the failure to comply with any Commission
 2 rule or standard. PG&E interprets authorities having jurisdiction to include
 3 agencies such as the CPUC, California Department of Forestry and Fire
 4 Protection, or the National Transportation Safety Board. The term authority
 5 having jurisdiction can also include PG&E itself if PG&E concludes that the
 6 definition of the SOM is met.

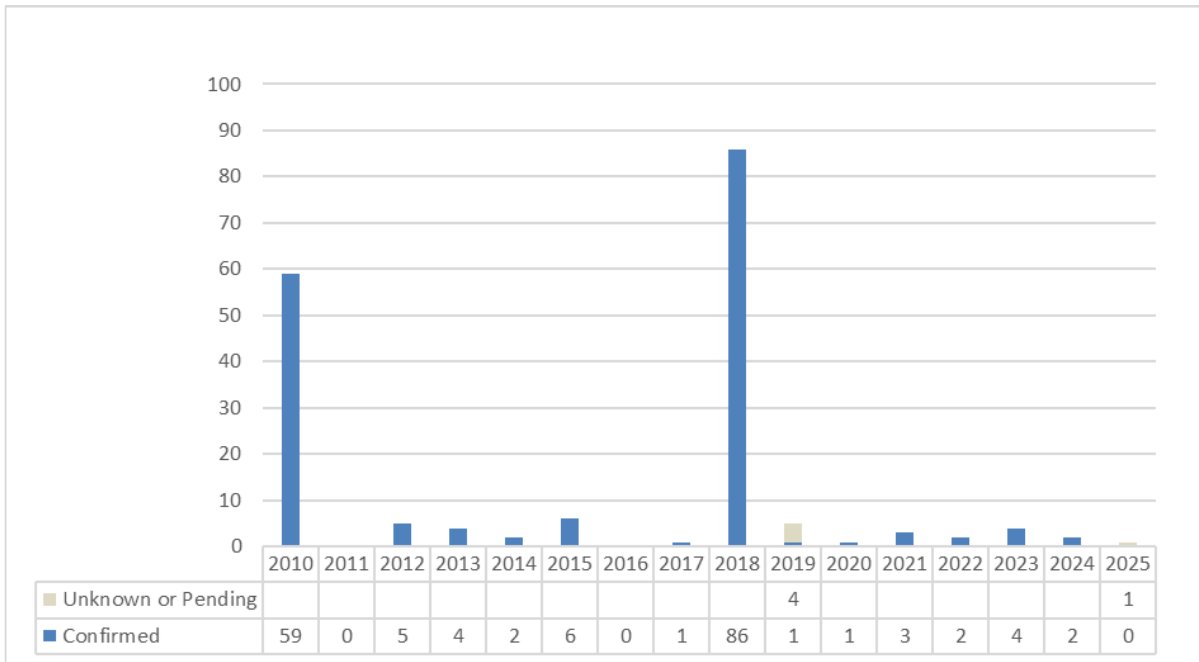
7 **3. Metric Performance for the Reporting Period**

8 The graphs included in Figures 1.3-1 and 1.3-2 are updated to include
 9 one third party MVI Public SIF incident that occurred on March 8, 2025.

**FIGURE 1.3-1
 NUMBER OF PUBLIC SIF ACTUAL INCIDENTS 2010 – 2025
 CONFIRMED AND PENDING**



**FIGURE 1.3-2
NUMBER OF PUBLIC SIF ACTUALS 2010 – 2025
CONFIRMED AND PENDING**



1 PG&E continues to evaluate its current and planned public safety work
 2 activities, as described in Section E below, further maturing its public
 3 incident investigation process. This includes the advancement of Public SIF
 4 Actual Metric definition requirements and learnings.

5 **C. (1.3) 1-Year Target and 5-Year Target**

6 **1. Updates to 1- and 5- Year Targets Since Last Report**

7 There have been no changes to the 1-year and 5-year targets since the
 8 last SOMs report filing for the Public SIF Actual metric, which is to
 9 demonstrate progress toward eliminating serious injuries and fatalities (zero
 10 Public SIF Actual incidents).

11 **2. Target Methodology**

12 With our stand of Everyone and Everything is Always Safe, our goal is
 13 the elimination of Public SIF Actual incidents resulting directly from incorrect
 14 operation of PG&E equipment, the failure, or malfunction of PG&E-owned
 15 equipment, or from PG&E’s failure to comply with any Commission rule or
 16 standard.

17 In consideration of the above, PG&E also reviewed the following factors:

- 1 • Historical Data and Current Reporting Period Trends: From 2010
2 through 2025, there were a total of 30 confirmed incidents where Public
3 SIF Actuals occurred (Figure 1.3-1), which resulted in a total of
4 176 public SIFs (Figure 1.3-2). There is one incident related to wildfire
5 where a serious injury or fatality to members of the public occurred that
6 is shown as “unknown” due to ongoing investigation and/or litigation.
7 Historical data will continue to inform PG&E’s plans and actions to
8 achieve its goal of zero public safety incidents.
- 9 • Benchmarking: Not available. As indicated in the SOMs third-party
10 audit final report, the definition of this metric is uniquely specific to the
11 Metric 1.3 reporting requirement, and there are no directly comparable
12 benchmarks at this time.
- 13 • Regulatory Requirements: CPUC, FERC, and Department of
14 Transportation (DOT), public safety reporting requirements
- 15 • Attainable Within Known Resources/Work Plan: Yes. PG&E’s work and
16 resource plan prioritizes public safety risk reduction. This includes
17 minimizing the risk of catastrophic wildfires in alignment with the
18 continued execution of the Wildfire Mitigation Plan and the maturation of
19 key wildfire mitigation strategies. It also includes mitigation of other
20 public safety risks related to the elimination of serious injuries and
21 fatalities (zero Public SIF Actual incidents).
- 22 • Appropriate/Sustainable Indicators for Enhanced Oversight
23 Enforcement: A 1-year goal of zero Public SIF Actuals was established
24 in 2022 and has not changed for 2026 through 2030 (5-year). The goal
25 reflects PG&E’s intent to immediately and continuously operate without
26 creating risk to the public; and
- 27 • Other Qualitative Considerations: PG&E’s approach is aligned to and
28 anchored on PG&E’s goal and commitment to “always” safe operations.

29 3. 2026 Target

30 As discussed above, PG&E’s 1-year target for the Public SIF Actual
31 Metric is to demonstrate progress toward eliminating serious injuries and
32 fatalities (zero Public SIF Actual incidents) resulting directly from the
33 incorrect operation of PG&E equipment, the failure, or malfunction of

1 PG&E-owned equipment, or PG&E’s failure to comply with any Commission
2 rule or standard.

3 **4. 2030 Target**

4 PG&E’s 5-year target for the Public SIF Actual metric is to demonstrate
5 progress toward eliminating serious injuries and fatalities (zero Public SIF
6 Actual incidents) resulting directly from the incorrect operation of PG&E
7 equipment, the failure, or malfunction of PG&E-owned equipment, or
8 PG&E’s failure to comply with any Commission rule or standard.

9 **D. (1.3) Performance Against Target**

10 **1. Progress Towards the 1-Year Directional Target**

11 [There are no confirmed Public SIF incidents for 2025 at this time.](#)

12 **2. Progress Towards the 5-Year Directional Target**

13 As discussed in Section E below, PG&E continues to deploy several
14 programs to maintain or improve the long-term performance of this metric
15 and to meet the Company’s 5-year performance target.

16 **E. (1.3) Current and Planned Work Activities**

17 Many of the current and planned activities to eliminate public safety
18 incidents are addressed by meeting key operational risk mitigations and are
19 discussed in other SOMs Chapters in this report. [Functional Areas incorporate
20 public safety into programs and initiatives, ensuring PG&E assets, equipment
21 and procedures address hazards that may impact the public.](#)

22 [Chapters 4.1 through 4.7 of this report discuss current and planned work
23 activities for reducing the risk of gas transmission and distribution system
24 equipment failure or malfunction.](#)

25 [Chapters 2.1 through 2.4, and Chapters 3.1 through 3.16 of this report
26 discuss current and planned work activities for reducing the risk of electric
27 transmission and distribution system equipment failure or malfunction.](#)

28 The current and planned work activities for reducing the risk of the power
29 generation hydroelectric system equipment failure or malfunction are included
30 below:

- 31 • [Power Generations Hydroelectric Programs](#): Hydroelectric programs
32 include procedures for planning for unusual water releases, along with
33 associated safety warnings.

- 1 • Power Generation Compliance Programs: Public Safety Plans are
2 published and routinely updated as required by PG&E hydroelectric facility
3 FERC licenses. FERC and the California Governor’s Office of Emergency
4 Services require an Emergency Action Plan (EAP) for all dams classified as
5 significant, high, or extremely high hazard. The Plans are tested annually
6 through drill, seminar, tabletop exercise, and/or functional exercise.
- 7 • Hydro Facility Unusual Water Releases and Water Safety Warning Standard
8 and Accompanying Procedure: Hydroelectric facility Unusual Water
9 Releases and Water Safety Warning documentation establishes Hydro
10 facility requirements for planning and making unusual water releases or high
11 flow events and their associated safety warnings. In 2025, a full
12 modernization of hydropower public safety signage was completed to
13 reduce public risk exposure. Updated signage improves hazard visibility,
14 strengthens legal enforceability, and enhances multilingual communication.
15 In addition, public safety has distributed hydroelectric safety brochures that
16 included dam safety, water safety, and recreational safety information. The
17 brochures notify the recipient that they live near a hydroelectric facility in order to
18 minimize potential reaction time and encourage them to be aware of dangerous
19 spring flows. In 2025, there were 5,810 hydro safety brochures mailed to
20 customers within a specified inundation zone.
- 21 • PG&E Dam Safety Surveillance and Monitoring Program: Dam surveillance
22 involves the collection of data by various means, including inspections and
23 instrumentation, whereas monitoring involves the review of the collected
24 data as obtained and over time for any adverse trends;
- 25 • Canals and Waterways Safety: PG&E Power Generation and external
26 public safety representatives successfully implemented rope systems
27 designed to enable members of the public who might accidentally fall into a
28 hydro canal to pull themselves out of danger. Since 2019, an additional
29 8.3 miles of barrier fencing has been installed along with
30 139 newly-designed escape ladders. In 2025, there were 1,023 canal safety
31 brochures mailed to customers that have canals bisecting their private
32 properties. 2025 improvements also include concrete vehicle barriers and
33 updated No Trespassing signage to prevent unauthorized OHV access to
34 the Towle Canal berm to prevent berm collapse hazards and enhance public

1 awareness of restricted areas, and the addition of glow tape on pylons and
2 grab cables at multiple escape ladder locations to improve nighttime visibility
3 of self-egress points.

- 4 • Recreation Safety Posters are posted for recreation sites identified below
5 time sensitive EAP dams. These recreation areas include campgrounds,
6 river access, trails, and boat ramps. Recreation safety posters illustrate
7 what to do in the event of a high flow event or dam safety emergency.
8 Posters provide the public with information on inundation areas, warning
9 signs of a dam safety emergency, safety precautions, and local agency
10 emergency contacts in order to prevent, moderate, or alleviate the effects of
11 an incident. Annually, public safety works with land agents to check all
12 locations and replace signage where needed.
- 13 • K through 8th grade safety awareness education. Power Gen oversees a
14 long-standing utility public safety awareness education initiative that offers
15 various interactive and educational materials and programs for K-8
16 educators, their students, and students' families. These resources help
17 increase student awareness of utility safety issues, including safety around
18 hydroelectric facilities and waterways. The content of the materials provided
19 to teachers are aligned with STEM (Science, Technology, Engineering, and
20 Math) standards. These classroom materials are offered to districts and
21 educators in all zip codes within PG&E's service territory. Educators are
22 made aware of these resources using a blend of direct mailing, and
23 one-on-one conversations between company representatives and
24 stakeholders. Results of a 2025 study to verify the impact of the educational
25 materials on students' understanding and awareness of key electrical,
26 hydropower, and natural gas safety guidelines and scientific concepts
27 indicated significant student test score improvements after the class
28 reviewed the materials. This supports that most students' awareness and
29 understanding of electrical, hydropower, and natural gas safety principles
30 and related scientific concepts were improved by exposure to the booklets,
31 regardless of their general academic proficiency.

32 Current and planned work activities for Transportation Safety include
33 PG&Es continued focus on eliminating Public SIF incidents with improvement in

1 2025 performance compared to 2024 due to continued cross-functional
2 collaboration.

- 3 • Federal and State motor vehicle safety compliance assurance. PG&E's
4 Transportation Safety organization ensures compliance with Federal DOT
5 and California Vehicle Code requirements which emphasize public and
6 workforce safety.
- 7 • Drivers Scorecard. Drivers Complaint Rate metric data is used to inform the
8 Drivers Scorecard, which provides leaders a continuous review of the
9 drivers' preventative motor vehicle incidents, and call Complaints. The
10 scorecard establishes point limits when action needs to be taken and also
11 contains motor vehicle training details. This scorecard is designed to
12 provide insights and ability for leaders to provide employees with timely
13 coaching and to reduce overall Motor Vehicle Safety Incident risk.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.1
SYSTEM AVERAGE INTERRUPTION
DURATION INDEX (SAIDI)
(UNPLANNED)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.1
SYSTEM AVERAGE INTERRUPTION
DURATION INDEX (SAIDI)
(UNPLANNED)

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2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 2.1**
4 **SYSTEM AVERAGE INTERRUPTION**
5 **DURATION INDEX (SAIDI)**
6 **(UNPLANNED)**

7 The material updates to this chapter since the September 30, 2025 report are
8 identified in blue font.

9 **A. (2.1) Overview**

10 **1. Metric Definition**

11 Safety and Operational Metric (SOM) 2.1 – System Average Interruption
12 Duration Index (SAIDI) (Unplanned) is defined as:

13 *SAIDI (Unplanned) = average duration of sustained interruptions per*
14 *metered customer due to all unplanned outages, excluding on Major Event*
15 *Days (MED), in a calendar year. “Average duration” is defined as: Sum of*
16 *(duration of interruption * # of customer interruptions)/Total number of*
17 *customers served. “Duration” is defined as: Customer hours of outages.*
18 *Includes all transmission and distribution outages. Excludes ISO outages.*

19 **2. Introduction of Metric**

20 SAIDI (Unplanned) measures the total number of minutes (or hours) of
21 sustained service interruptions the average Pacific Gas and Electric
22 Company (PG&E) customer experiences from unplanned outages in a year.
23 A sustained interruption is defined as an interruption lasting more than
24 5 minutes.

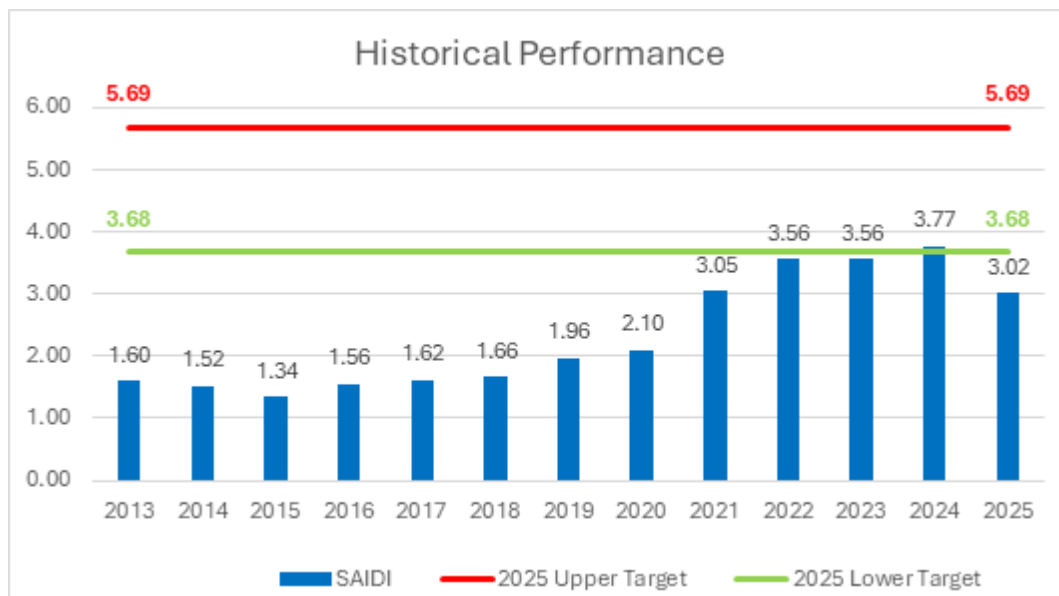
25 **B. (2.1) Metric Performance**

26 **1. Historical Data (2013 –2025)**

27 Historical performance for this metric covers periods 2013 through 2025.
28 SAIDI (Unplanned) performance for 2025 was 3.02 hours. This represents a
29 20 percent decrease from the prior year. The upward trend observed
30 beginning in the 2019-2021 timeframe was driven by the establishment and
31 expansion of wildfire mitigation practices, particularly EPSS implementation.
32 Performance over the total historical reporting period (2013-2025) also

1 reflects the ongoing impacts of system degradation consistent with
2 equipment aging, outages caused by vegetation, equipment, and third-party
3 damage (as top cause examples), and weather events. (See Figure 2.1-1
4 below).

**FIGURE 2.1-1
SAIDI (UNPLANNED)
HISTORICAL PERFORMANCE (2013- 2025)**



Note: The data in this figure is subject to change based on continuing review of prior period information.

2. Data Collection Methodology

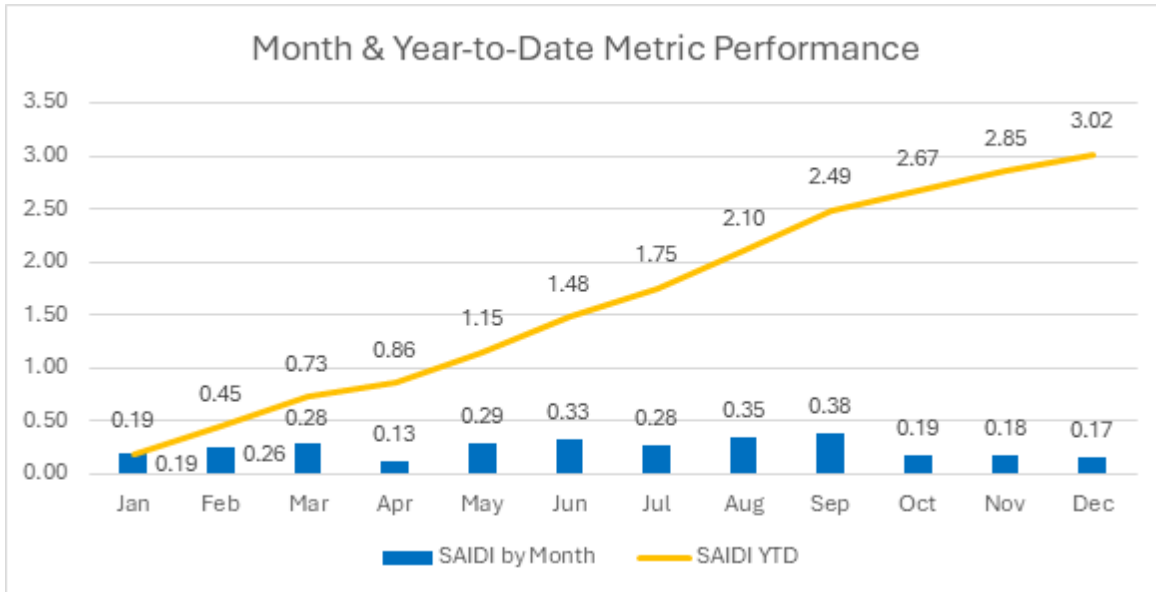
- PG&E’s outage reporting system consists of multiple components. A key component used for outage records is the Integrated Logging and Information System (ILIS).
- PG&E’s outage data reporting process, standards, and tools are documented and maintained in Utility procedure [TD-2200P-01 Outage Reporting Details and Accuracy Verification Process](#).
- Qualification of Customer Count Calculations: PG&E is executing a multi-year plan to align its reliability reporting practices with the IEEE 1366-2022 standard. As part of this plan, SOMs reliability metric data for 2025 is based on customer counts that reflect metered customers with active service agreements. Due to limitations in available data and ongoing efforts to improve methodologies for

1 determining accurate customer count estimates, PG&E has retained an
2 independent third party to refine how PG&E calculates the customer
3 minutes. The customer count from this analysis is the basis for the
4 SOMs metric calculations in this report and is subject to change as
5 methodologies are refined.

6 **3. Metric Performance for the Reporting Period**

7 SAIDI (Unplanned) performance for 2025 was 3.02 hours, which is
8 below the prior 3-year average. Improved restoration performance,
9 including faster restoration across storm and non-storm conditions, and
10 reduced EPSS-related customer impact under milder fire-weather conditions
11 were primary contributors. Reliability focused projects and inspections were
12 executed in 2025, including safe completion of ~1,300 high impact reliability
13 projects and sectionalization of ~90 worst performing circuits. These system
14 improvements seek to minimize the scale of sustained interruption
15 customers feel each year. As mentioned, outage restoration time (as
16 measured by CAIDI - Customer Average Interruption Duration Index) also
17 contributed to SAIDI results with improved performance in 2025 compared
18 to the prior 3 year average.

**FIGURE 2.1-2
SAIDI (UNPLANNED)
PERFORMANCE 2025**



Note: The data in this figure is subject to change based on continuing review of prior period information.

C. (2.1) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

The 1- and 5-year targets have shifted from being expressed as a range to a single upper target value. This upper target band remains unchanged while the lower target band has been removed.

2. Target Methodology

The target methodology remains unchanged from the 2025 approach. The target baseline is calculated using a three-year average of past performance from 2022 through 2024. The annual target is then set by applying a 50 percent increase to this baseline, resulting in a single fixed target value. The methodology continues to incorporate historical system performance, anticipated operational measures such as EPSS and DCD impacts, and weather-related variables to maintain consistency in evaluating performance under expected operational and environmental conditions.

- Historical Data and Trends: Considers past performance data and trends;
- Benchmarking: PG&E is currently in the fourth quartile;

- 1 • Regulatory Requirements: CPUC Decision (D.20-05-053);
- 2 • Appropriate/Sustainable Indicators for Enhanced Oversight and
- 3 Enforcement: The target for this metric is suitable for Enhanced
- 4 Oversight and Enforcement as it accounts for our current work plan and
- 5 the unknowns of EPSS;
- 6 • Attainable with Known Resources/Work Plan: Yes; and
- 7 • Other Considerations: None.

8 **3. 2026 Target**

9 The 2026 target is 5.69 hours. PG&E continues to monitor historical
10 and current system performance, year-over-year weather variables, and
11 deployment of operational measures. Targets are evaluated semi-annually
12 and have the potential to be adjusted in each subsequent reporting period.

13 **4. 2030 Target**

14 The 2030 target is 5.69 hours. PG&E continues to monitor historical
15 and current system performance, year-over-year weather variables, and
16 deployment of operational measures. Targets are evaluated semi-annually
17 and have the potential to be adjusted in each subsequent reporting period.

18 **D. (2.1) Performance Against Target**

19 **1. Progress Towards 1-Year Target**

20 Performance for 2025 recorded an average duration of 3.02 hours of
21 sustained interruptions due to unplanned outages per metered customer.
22 This performance is within target range. While weather and EPSS/DCD
23 settings are variables that may impact 2026 performance, PG&E expects
24 2026 performance to remain below the upper target band.

25 **2. Progress Towards 5-Year Target**

26 PG&E considers current and historical performance, current and future
27 planned work activities, and focuses on continuous improvement and
28 expects metric performance to perform under the 5-year target.

29 **E. (2.1) Current and Planned Work Activities**

30 PG&E implements a portfolio of ongoing and planned work activities
31 designed to reduce the frequency and duration of sustained customer outages,

1 thereby supporting improvements in System Average Interruption Duration Index
2 (SAIDI). These activities include the following but are not limited to:

- 3 • [Reliability Project Portfolio](#): This portfolio comprises ongoing grid reliability
4 construction, maintenance, and upgrade work that addresses drivers of
5 sustained outage frequency on the system. Activities include equipment
6 installations and replacements, fuse and sectionalizing improvements, and
7 corrective work to address identified condition issues.
- 8 • [Circuit Blitz](#): Circuit Blitz activities consist of focused inspections on
9 selected circuits with elevated interruption frequency and prioritizing
10 corrective work to reduce the likelihood of sustained interruptions. These
11 inspections identify vegetation encroachments, equipment deficiencies, and
12 condition issues that can initiate faults.
- 13 • [2+ Crew Dispatching](#): The 2+ crew dispatching model assigns one line crew
14 and two trouble men at outage initiation to accelerate fault location and
15 isolation. Faster identification and sectionalizing reduce the number of
16 customers experiencing sustained interruptions.
- 17 • [Vegetation Management](#): Vegetation-related faults are a primary contributor
18 to sustained outages. PG&E's vegetation management program focuses on
19 maintaining required clearances and addressing high-risk spans and circuits
20 to reduce vegetation contact and improve accessibility for restoration
21 activities.
- 22 • [Asset Replacement \(Overhead, Underground\)](#): PG&E's asset replacement
23 programs address aging infrastructure. Replacing overhead and
24 underground equipment prior to in-service failure reduces unplanned
25 outages and limits the need for complex repairs that can extend restoration
26 timelines.
- 27 • [Grid Design and System Hardening](#): Grid design improvements and system
28 hardening measures reduce the frequency of outages by strengthening
29 infrastructure against environmental and operational stressors.
- 30 • [Downed Conductor Detection](#): Downed conductor detection technologies
31 reduce the likelihood of extended or repeat interruptions by enabling rapid
32 identification and isolation of faulted segments. Early detection limits
33 secondary damage and reduces the potential for multiple customer
34 interruptions.

- 1 • Overhead/Underground Critical Operating Equipment Replacement Work:
2 Replacement and refurbishment of critical operating equipment improves
3 system operability and reliability. Modernized equipment supports more
4 effective sectionalizing and restoration during outage events.
- 5 • Overhead Fuse Installation: Overhead fuse installations are used to limit the
6 extent of outages by isolating faulted sections of the circuit. Properly
7 coordinated fusing reduces the number of customers affected during outage.
- 8 • Fault Location, Isolation, and Service Restoration: Fault Location, Isolation,
9 and Service Restoration capabilities support faster identification of fault
10 locations and more efficient switching. These technologies reduce reliance
11 on manual processes and reduce the potential for interruptions on
12 unaffected portions of the circuit.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.2
SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX
(SAIFI)
(UNPLANNED)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.2
SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)
(UNPLANNED)

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 2.2**
4 **SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)**
5 **(UNPLANNED)**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (2.2) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metric (SOM) 2.2 – System Average Interruption
11 Frequency (SAIFI)(Unplanned) is defined as:

12 *SAIFI (Unplanned) = average frequency of sustained interruptions due*
13 *to all unplanned outages per metered customer, except on Major Event*
14 *Days (MED), in a calendar year. “Average frequency” is defined as: Total #*
15 *of customer interruptions/Total # of customers served. Includes all*
16 *transmission and distribution outages.*

17 **2. Introduction of Metric**

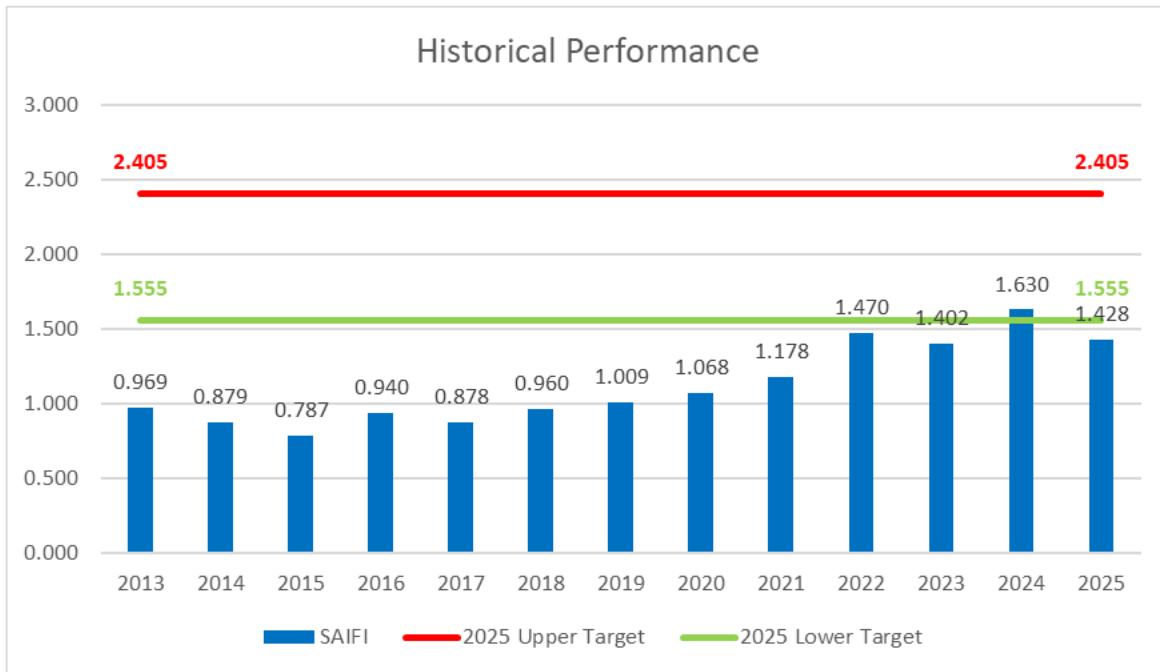
18 SAIFI (Unplanned) is a measure of the total number of unplanned
19 sustained service interruptions that the average Pacific Gas and Electric
20 Company (PG&E) customer experiences in year. A sustained interruption is
21 defined as an interruption lasting more than 5 minutes.

22 **B. (2.2) Metric Performance**

23 **1. Historical Data (2013 – 2025)**

24 Historical performance for SAIFI (Unplanned) covers periods 2013
25 through 2025. This represents a 12 percent decrease from the prior year.
26 The upward trend observed beginning in the 2019-2021 timeframe was
27 driven by the establishment and expansion of wildfire mitigation practices,
28 particularly EPSS implementation. Performance over the total historical
29 reporting period (2013-2025) also reflects the ongoing impacts of system
30 degradation consistent with equipment aging, outages caused by
31 vegetation, equipment, and third-party damage (as top cause examples),
32 and weather events. (See Figure 2.2-1 below).

**FIGURE 2.2-1
SAIFI (UNPLANNED)
HISTORICAL PERFORMANCE
2013- 2025**



Note: The data in this figure is subject to change based on continuing review of prior period information.

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2. Data Collection Methodology

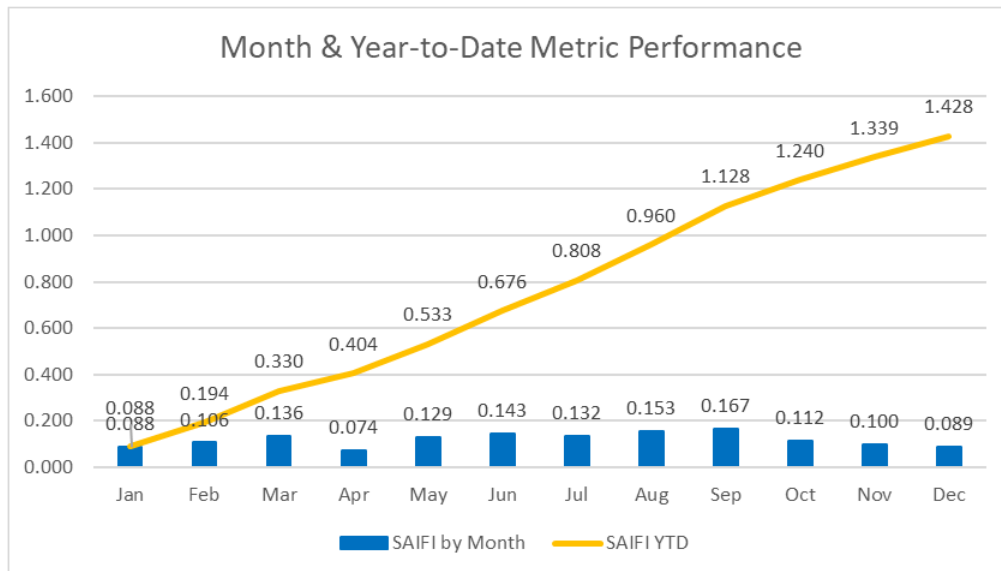
- PG&E’s outage reporting system consists of multiple components. A key component used for outage records is the Integrated Logging and Information System (ILIS).
- PG&E’s outage data reporting process, standards, and tools are documented and maintained in Utility procedure [TD-2200P-01 Outage Reporting Details and Accuracy Verification Process](#).
- Qualification of Customer Count Calculations: PG&E is executing a multi-year plan to align its reliability reporting practices with the IEEE 1366-2022 standard. As part of this plan, SOMs reliability metric data for 2025 is based on customer counts that reflect metered customers with active service agreements. Due to limitations in available data and ongoing efforts to improve methodologies for determining accurate customer count estimates, PG&E has retained an independent third party to refine how PG&E calculates the customer

1 minutes. The customer count from this analysis is the basis for the
2 SOMs metric calculations in this report and is subject to change as
3 methodologies are refined.

4 3. Metric Performance for the Reporting Period

5 SAIFI (Unplanned) performance for 2025 was 1.428, which is slightly
6 below the prior 3-year average. Generally, the total number of unplanned
7 outages in 2025 was on par with the prior three years, meaning lower SAIFI
8 (and SAIDI) results in 2025 are driven by less customers being impacted by
9 outages (and for shorter amounts of time.) Like other reliability metrics,
10 reduced EPSS impacts due to more mild fire-weather conditions compared
11 to prior years is a driver of overall customer outage impacts in 2025.
12 Reliability focused projects and inspections were executed in 2025,
13 including safe completion of ~1,300 high impact reliability projects and
14 sectionalization of ~90 worst performing circuits. These system
15 improvements seek to minimize the scale of sustained interruption
16 customers feel each year.

FIGURE 2.2-2
SAIFI (UNPLANNED)
METRIC PERFORMANCE
2025



Note: The data in this figure is subject to change based on continuing review of prior period information. Year-to-Date performance from January through June has been updated.

1 **C. (2.2) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 The 1- and 5-year targets have shifted from being expressed as a range
4 to a single upper target value. This upper target band value remains
5 unchanged while the lower target band has been removed.

6 **Target Methodology**

7 The target methodology remains unchanged from the 2025 approach.
8 The target baseline is calculated using a three-year average of past
9 performance from 2022 through 2024. The annual target is then set by
10 applying a 50 percent increase to this baseline, resulting in a single fixed
11 target value. The methodology continues to incorporate historical system
12 performance, anticipated operational measures such as EPSS and DCD
13 impacts, and weather-related variables to maintain consistency in evaluating
14 performance under expected operational and environmental conditions.

- 15 • Historical Data and Trends: Considers past performance data and
16 trends;
- 17 • Benchmarking: PG&E is currently in the fourth quartile;
- 18 • Regulatory Requirements: California Public Utilities Commission
19 Decision (D.20-05-053);
- 20 • Appropriate/Sustainable Indicators for Enhanced Oversight and
21 Enforcement: The target for this metric is suitable for Enhanced
22 Oversight and Enforcement as it accounts for our current work plan and
23 the unknowns of EPSS;
- 24 • Attainable with Known Resources/Work Plan: Yes; and
- 25 • Other Considerations: None.

26 **2. 2026 Target**

27 The 2026 target is 2.405. PG&E continues to monitor historical and
28 current system performance, year-over-year weather variables, and
29 deployment of operational measures. Targets are evaluated semi-annually
30 and have the potential to be adjusted in each subsequent reporting period.

31 **3. 2030 Target**

32 The 2030 target is 2.405. PG&E continues to monitor historical and
33 current system performance, year-over-year weather variables, and

1 deployment of operational measures. Targets are evaluated semi-annually
2 and have the potential to be adjusted in each subsequent reporting period.

3 **D. (2.2) Performance Against Target**

4 **1. Progress Towards 1-Year Target**

5 Performance for 2025 recorded an average frequency of 1.428
6 sustained interruptions due to unplanned outages per metered customer.
7 This performance is within target range. While weather and EPSS/DCD
8 settings are variables that may impact 2026 performance, PG&E expects
9 2026 performance to remain below the upper target band.

10 **2. Progress Towards 5-Year Target**

11 PG&E considers current and historical performance, current and future
12 planned work activities, and focuses on continuous improvement and
13 expects metric performance to perform under the 5-year target.

14 **E. (2.2) Current and Planned Work Activities**

15 PG&E implements a portfolio of ongoing and planned work activities that
16 address the leading causes of sustained customer interruptions, thereby
17 supporting improvements in System Average Interruption Frequency Index
18 (SAIFI). These activities include the following, but are not limited to:

- 19 • Reliability Project Portfolio: This portfolio comprises ongoing grid reliability
20 construction, maintenance, and upgrade work that addresses drivers of
21 sustained outage frequency on the system. Activities include equipment
22 installations and replacements, fuse and sectionalizing improvements, and
23 corrective work to address identified condition issues.
- 24 • Circuit Blitz: Circuit Blitz activities consist of focused inspections on
25 selected circuits with elevated interruption frequency and prioritizing
26 corrective work to reduce the likelihood of sustained interruptions. These
27 inspections identify vegetation encroachments, equipment deficiencies, and
28 condition issues that can initiate faults.
- 29 • Vegetation Management: Vegetation-related faults are a primary contributor
30 to sustained outages. PG&E's vegetation management program focuses on
31 maintaining required clearances and addressing high-risk spans and circuits
32 to reduce vegetation contact and improve accessibility for restoration
33 activities.

- 1 • Asset Replacement (Overhead, Underground): PG&E’s asset replacement
2 programs address aging infrastructure. Replacing overhead and
3 underground equipment prior to in-service failure reduces unplanned
4 outages and limits the need for complex repairs that can extend restoration
5 timelines.
- 6 • Grid Design and System Hardening: Grid design improvements and system
7 hardening measures reduce the frequency of outages by strengthening
8 infrastructure against environmental and operational stressors..
- 9 • Downed Conductor Detection: Downed conductor detection technologies
10 reduce the likelihood of extended or repeat interruptions by enabling rapid
11 identification and isolation of faulted segments. Early detection limits
12 secondary damage and reduces the potential for multiple customer
13 interruptions.
- 14 • Overhead/Underground Critical Operating Equipment Replacement Work:
15 Replacement and refurbishment of critical operating equipment improves
16 system operability and reliability. Modernized equipment supports more
17 effective sectionalizing and restoration during outage events.
- 18 • Overhead Fuse Installation: Overhead fuse installations are used to limit the
19 extent of outages by isolating faulted sections of the circuit. Properly
20 coordinated fusing reduces the number of customers affected during outage.
- 21 • Fault Location, Isolation, and Service Restoration (FLISR): FLISR
22 capabilities support faster identification of fault locations and more efficient
23 switching. These technologies reduce reliance on manual processes and
24 reduce the potential for interruptions on unaffected portions of the circuit.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.3
SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND
EQUIPMENT DAMAGE IN HFTD AREAS
(MAJOR EVENT DAYS)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.3
SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND
EQUIPMENT DAMAGE IN HFTD AREAS
(MAJOR EVENT DAYS)

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 2.3**
4 **SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND**
5 **EQUIPMENT DAMAGE IN HFTD AREAS**
6 **(MAJOR EVENT DAYS)**

7 The material updates to this chapter since the September 30, 2025 report are
8 identified in blue font.

9 **A. (2.3) Overview**

10 **1. Metric Definition**

11 Safety and Operational Metric (SOM) 2.3 – System Average Outages
12 Due to Vegetation and Equipment Damage in High Fire Threat District
13 (HFTD) Areas (Major Event Days (MED)) is defined as:

14 *Average number of sustained outages on MED per 100 circuit miles in*
15 *HFTD per metered customer, in a calendar year, where each sustained*
16 *outage is defined as: total number of customers interrupted / total number of*
17 *customers served.*

18 PG&E defines a sustained outage as an outage lasting more than
19 5 minutes in alignment with CPUC and IEEE 1366-2022 reporting
20 standards.

21 **2. Introduction of Metric**

22 Based on Pacific Gas and Electric Company’s (PG&E) understanding,
23 this metric is specific to Customers Experiencing Sustained Outages
24 (CESO) per 100 circuit miles in Tier 2 and Tier 3 HFTD areas, where the
25 basic cause is vegetation or equipment failure during MEDs.

26 **3. Audit Results**

27 In the Audit Report, Metric 2.3 received a Metric Accuracy Finding of
28 “Significant.” The Other Findings for this metric were “Discrepancy between
29 CESO data pulled monthly and annually.”¹ This finding is closed with
30 respect to 2025 and going forward, but remains open with respect to

1 Audit Report, p. 8, Table 1-1.

1 impacts of prior reporting years of the HFTD issues discussed below. PG&E
2 clarified CESO discrepancies and that not all outages may have been
3 officially closed at the time of the 2023 mid-year report, and outages may
4 still be reviewed and changed months after the fact due to internal findings.

5 Regarding HFTD discrepancies, the Outage Foundry Ontology dataset
6 has been joined with the latest HFTD version dataset in Foundry to create
7 an outage dataset with a single HFTD designation for our distribution level
8 outages coming from our Integrated Logging and Information System (ILIS)
9 source system.

10 However, this metric also counts distribution customer counts caused by
11 transmission level outages. Since those outages happen at the
12 transmission level, the source system used to derive the distribution
13 customer counts (ILIS) does not know the latitude and longitude of the
14 transmission outage event itself, but rather only the downstream distribution
15 customer impacts, which is needed for this metric. Our transmission level
16 outages are tracked in a different source system called Transmission
17 Operations Tracking and Logging (TOTL). This system has correct latitude
18 and longitude and correct HFTD assignments, but correlating the
19 transmission level outage to the correct distribution impacts across two
20 different source systems is a manual effort.

21 When a transmission level outage event happens today, operators
22 record them in Distribution Management System (DMS) on a substation
23 device. Frequently, this is a fictitious "Source" device used to simulate
24 transmission loss at a substation since transmission lines are not mapped in
25 DMS. Because "Source" devices do not exist in Geographic Information
26 System (GIS), they lack latitude/longitude data, which prevents HFTD
27 assignment. If a GIS-linked device (e.g., breaker or switcher) is used,
28 latitude/longitude is available and HFTD is applied.

29 PG&E will continue manual efforts to ensure that transmission level
30 event HFTD data captured in TOTL correctly correlates to the distribution
31 customer impact data found in ILIS. PG&E is exploring processes and tools
32 that may reduce this manual effort going forward.

33 PG&E believes this issue is resolved with respect to the 2025
34 performance and going forward. However, PG&E is also assessing

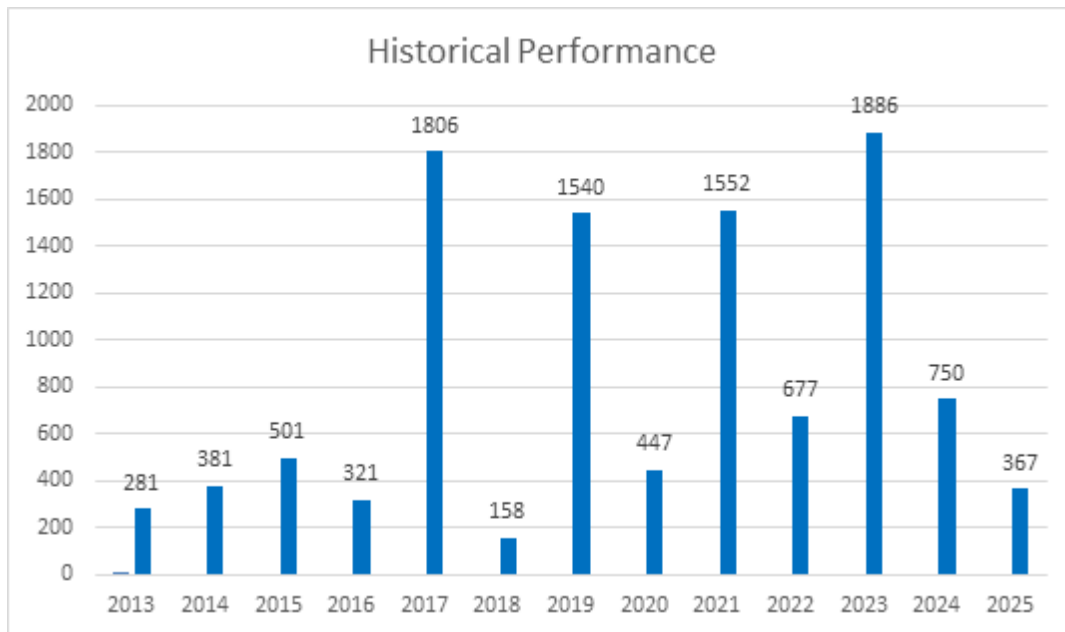
1 historical reporting and technical feasibility for applying any corrections that
2 may be needed.

3 **B. (2.3) Metric Performance**

4 **1. Historical Data (2013 – 2025)**

5 Historical performance exhibits year-to-year variability of frequency,
6 severity, and location of MED weather conditions. While ongoing mitigations
7 aim to reduce vegetation and equipment caused wildfire risk within HFTD,
8 variability in each year’s frequency of MED-level weather systems, and
9 therefore the number of MEDs registered in that year, is the largest driver of
10 and correlation to historical performance patterns.

**FIGURE 2.3-1
CESO PER 100 CIRCUIT MILES (HFTD) (MED)
VEG & EQUIP FAILURE
2013- 2025**



Note: The data in this figure is subject to change based on continuing review of prior period information. Historical data for 2022 has been updated to reflect accurate performance.

11 **2. Data Collection Methodology**

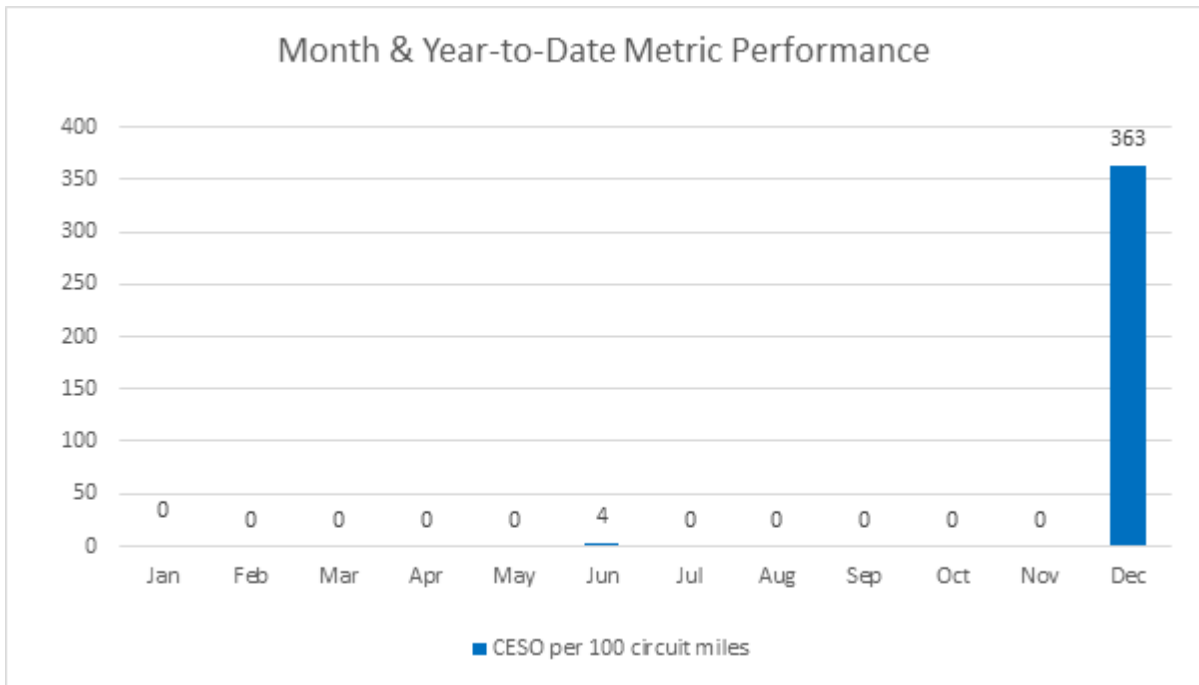
- 12 • PG&E’s outage reporting system consists of multiple components. A
13 key component used for outage records is the ILIS.

- 1 • PG&E's outage data reporting process, standards, and tools are
2 documented and maintained in Utility procedure
- 3 • [TD-2200P-01 Outage Reporting Details and Accuracy Verification](#)
4 [Process.](#)
- 5 • To determine whether an outage event occurs in a Tier 2/3 HFTD areas,
6 PG&E uses the latitude and longitude of the relevant operating device.
- 7 • Qualification of Customer Count Calculations: PG&E is executing a
8 multi-year plan to align its reliability reporting practices with the
9 IEEE 1366-2022 standard. As part of this plan, SOMs reliability metric
10 data for 2025 is based on customer counts that reflect metered
11 customers with active service agreements. Due to limitations in
12 available data and ongoing efforts to improve methodologies for
13 determining accurate customer count estimates, PG&E has retained an
14 independent third party to refine how PG&E calculates the customer
15 minutes. The customer count from this analysis is the basis for the
16 SOMs metric calculations in this report and is subject to change as
17 methodologies are refined.

18 **3. Metric Performance for the Reporting Period**

19 [Metric performance for 2025 recorded 367 CESO per 100 circuit miles in](#)
20 [HFTD areas during MEDs where vegetation and equipment failure were the](#)
21 [basic causes \(Figure 2.3-2\). Performance reflects a lower number of MED](#)
22 [days compared to prior years. PG&E's service territory experienced one](#)
23 [MED in June and four MEDs in late December, with five total for the year.](#)

**FIGURE 2.3-2
CESO PER 100 CIRCUIT MILES (HFTD) (MED)
VEG & EQUIP FAILURE
2025**



Note: The data in this figure is subject to change based on continuing review of prior period information.

1 **C. (2.3) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 No updates to the 1- and 5-year targets. This is directional-only metric
4 without a specific performance target.

5 **2. Target Methodology**

- 6 • Directional Only: Maintain (stay within historical range and assumes the
7 response stays the same in events);
- 8 • Historical Data and Trends: Considers past performance data and
9 trends;
- 10 • Benchmarking: Not benchmarkable
- 11 • Regulatory Requirements: California Public Utilities Commission
12 Decision (D.) (D.20-05-053);
- 13 • Appropriate/Sustainable Indicators for Enhanced Oversight and
14 Enforcement: The directional target for this metric is suitable for

1 Enhanced Oversight and Enforcement as it states we are to remain
2 within historical performance range while accounting for the randomness
3 of weather patterns and impacts of climate change;

- 4 • Attainable with Known Resources/Work Plan: Yes; and
- 5 • Other Considerations: None.

6 **D. (2.3) Performance Against Target Progress**

7 **1. Progress Towards the 1-Year Target**

8 This is a directional-only metric without a specific performance target.
9 Metric performance for 2025, performed within historical range. PG&E
10 service territories experienced five MEDs in 2025, one MED in June and
11 four MEDs in late December. See Figure 2.3-1 above.

12 **2. Progress Towards the 5-Year Target**

13 This is a directional-only metric without a specific performance target.

14 **E. (2.3) Current and Planned Work Activities**

15 PG&E operates a number of programs designed to reduce vegetation- and
16 equipment-caused outages for customers in HFTDs. These activities include
17 the following, but are not limited to:

- 18 • Reliability Project Portfolio: This portfolio comprises ongoing grid reliability
19 construction, maintenance, and upgrade work that addresses drivers of
20 sustained outage frequency on the system. Activities include equipment
21 installations and replacements, fuse and sectionalizing improvements, and
22 corrective work to address identified condition issues.
- 23 • Circuit Blitz: Circuit Blitz activities consist of focused inspections on
24 selected circuits with elevated interruption frequency and prioritizing
25 corrective work to reduce the likelihood of sustained interruptions. These
26 inspections identify vegetation encroachments, equipment deficiencies, and
27 condition issues that can initiate faults.
- 28 • Vegetation Management: Vegetation-related faults are a primary contributor
29 to sustained outages. PG&E's vegetation management program focuses on
30 maintaining required clearances and addressing high-risk spans and circuits
31 to reduce vegetation contact and improve accessibility for restoration
32 activities.

- 1 • Asset Replacement (Overhead, Underground): PG&E’s asset replacement
2 programs address aging infrastructure. Replacing overhead and
3 underground equipment prior to in-service failure reduces unplanned
4 outages and limits the need for complex repairs that can extend restoration
5 timelines.
- 6 • Grid Design and System Hardening: Grid design improvements and system
7 hardening measures reduce the frequency of outages by strengthening
8 infrastructure against environmental and operational stressors.
- 9 • Downed Conductor Detection: Downed conductor detection technologies
10 reduce the likelihood of extended or repeat interruptions by enabling rapid
11 identification and isolation of faulted segments. Early detection limits
12 secondary damage and reduces the potential for multiple customer
13 interruptions.
- 14 • Overhead/Underground Critical Operating Equipment Replacement Work:
15 Replacement and refurbishment of critical operating equipment improves
16 system operability and reliability. Modernized equipment supports more
17 effective sectionalizing and restoration during outage events.
- 18 • Overhead Fuse Installation: Overhead fuse installations are used to limit the
19 extent of outages by isolating faulted sections of the circuit. Properly
20 coordinated fusing reduces the number of customers affected during outage.
- 21 • Fault Location, Isolation, and Service Restoration: Fault Location, Isolation,
22 and Service Restoration capabilities support faster identification of fault
23 locations and more efficient switching. These technologies reduce reliance
24 on manual processes and reduce the potential for interruptions on
25 unaffected portions of the circuit.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.4
SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND
EQUIPMENT DAMAGE IN HFTD AREAS
(NON-MAJOR EVENT DAYS)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 2.4
SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND
EQUIPMENT DAMAGE IN HFTD AREAS
(NON-MAJOR EVENT DAYS)

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 2.4**
4 **SYSTEM AVERAGE OUTAGES DUE TO VEGETATION AND**
5 **EQUIPMENT DAMAGE IN HFTD AREAS**
6 **(NON-MAJOR EVENT DAYS)**

7 The material updates to this chapter since the September 30, 2025 report are
8 identified in blue font.

9 **A. (2.4) Overview**

10 **1. Metric Definition**

11 Safety and Operational Metric (SOM) 2.4 – System Average Outages
12 due to Vegetation and Equipment Damage in High Fire Threat District
13 (HFTD) Areas (Non-Major Event Days) is defined as:

14 *Average number of sustained outages on Non-Major Event Days (MED)*
15 *per 100 circuit miles in High Fire Threat District (HFTD) per metered*
16 *customer, in a calendar year, where each sustained outage is defined as:*
17 *total number of customers interrupted/total number of customers served.*

18 PG&E defines a sustained outage as an outage lasting more than
19 5 minutes in alignment with CPUC and IEEE 1366-2022 reporting
20 standards.

21 **2. Introduction of Metric**

22 Based on Pacific Gas and Electric Company’s (PG&E) understanding,
23 this metric is specific to Customers Experiencing Sustained Outages
24 (CESO) per 100 circuit miles in Tier 2/3 HFTD areas, where the basic cause
25 is vegetation or equipment failure during non-MEDs.

26 **3. Audit Results**

27 In the Audit Report, Metric 2.4 received a Metric Accuracy Finding of
28 “Significant.” The Other Findings for this metric were “Discrepancy between
29 CESO data pulled monthly and annually.”¹ This finding is closed with
30 respect to 2025 and going forward, but remains open with respect to

1 Audit Report, p. 8, Table 1-1.

1 impacts of prior reporting years of the HFTD issues discussed below. PG&E
2 clarified CESO discrepancies and that not all outages may have been
3 officially closed at the time of the 2023 mid-year report, and outages may
4 still be reviewed and changed months after the fact due to internal findings.

5 Regarding HFTD discrepancies, the Outage Foundry Ontology dataset
6 has been joined with the latest HFTD version dataset in Foundry to create
7 an outage dataset with a single HFTD designation for our distribution level
8 outages coming from our Integrated Logging and Information System (ILIS)
9 source system.

10 However, this metric also counts distribution customer counts caused by
11 transmission level outages. Since those outages happen at the
12 transmission level, the source system used to derive the distribution
13 customer counts (ILIS) does not know the latitude and longitude of the
14 transmission outage event itself, but rather only the downstream distribution
15 customer impacts, which is needed for this metric. Our transmission level
16 outages are tracked in a different source system called Transmission
17 Operations Tracking and Logging (TOTL). This system has correct latitude
18 and longitude and correct HFTD assignments, but correlating the
19 transmission level outage to the correct distribution impacts across two
20 different source systems is a manual effort.

21 When a transmission level outage event happens today, operators
22 record them in Distribution Management System (DMS) on a substation
23 device. Frequently, this is a fictitious "Source" device used to simulate
24 transmission loss at a substation since transmission lines are not mapped in
25 DMS. Because "Source" devices do not exist in Geographic Information
26 System (GIS), they lack latitude/longitude data, which prevents HFTD
27 assignment. If a GIS-linked device (e.g., breaker or switcher) is used,
28 latitude/longitude is available and HFTD is applied.

29 PG&E will continue manual efforts to ensure that transmission level
30 event HFTD data captured in TOTL correctly correlates to the distribution
31 customer impact data found in ILIS. PG&E is exploring processes and tools
32 that may reduce this manual effort going forward.

33 PG&E believes this issue is resolved with respect to the 2025
34 performance and going forward. However, PG&E is also assessing

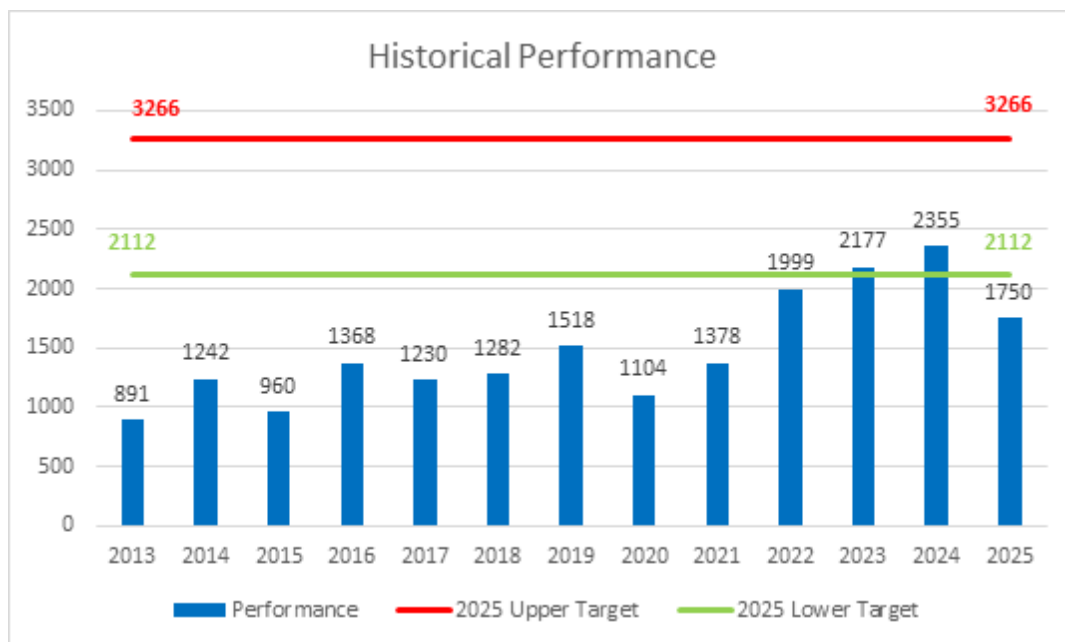
1 historical reporting and technical feasibility for applying any corrections that
2 may be needed.

3 **B. (2.4) Metric Performance**

4 **1. Historical Data (2013 –2025)**

5 Historical performance for this metric covers periods 2013 through 2025.
6 This represents a 26 percent decrease from the prior year. The upward
7 trend observed beginning in the 2019-2021 timeframe was driven by the
8 establishment and expansion of wildfire mitigation practices, particularly
9 EPSS implementation. Performance over the total historical reporting period
10 (2013-2025) also reflects the ongoing impacts of system degradation
11 consistent with equipment aging and weather events.

FIGURE 2.4-1
CESO PER 100 CIRCUIT MILES (HFTD) (NON-MED)
VEG & EQUIP FAILURE
2013- 2025



Note: The data in this figure is subject to change based on continuing review of prior period information.

12 **2. Data Collection Methodology**

13 Data Sources:

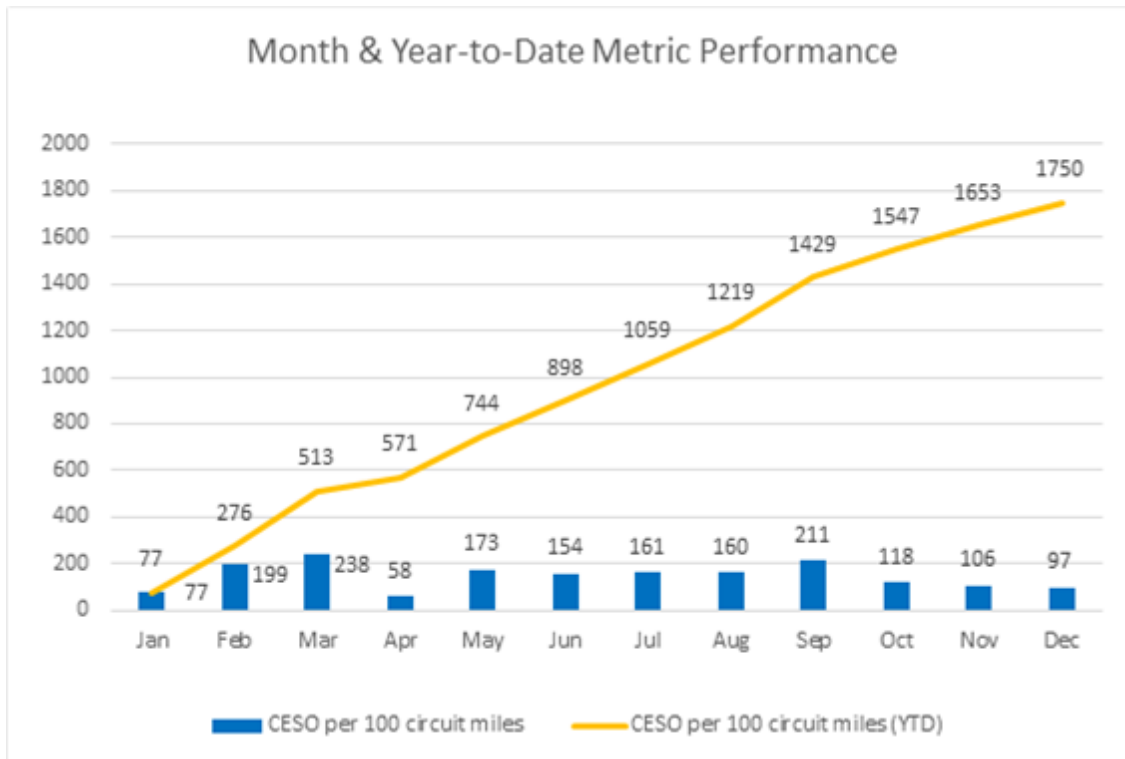
- 1 • PG&E's outage reporting system consists of multiple components. A
2 key component used for outage records is the ILIS.
- 3 • PG&E's outage data reporting process, standards, and tools are
4 documented and maintained in Utility procedure [TD-2200P-01 Outage](#)
5 [Reporting Details and Accuracy Verification Process](#).
- 6 • To determine whether an outage event occurs in a Tier 2/3 HFTD areas,
7 PG&E uses the latitude and longitude of the relevant operating device.
- 8 • Qualification of Customer Count Calculations: PG&E is executing a
9 multi-year plan to align its reliability reporting practices with the
10 IEEE 1366-2022 standard. As part of this plan, SOMs reliability metric
11 data for 2025 is based on customer counts that reflect metered
12 customers with active service agreements. Due to limitations in
13 available data and ongoing efforts to improve methodologies for
14 determining accurate customer count estimates, PG&E has retained an
15 independent third party to refine how PG&E calculates the customer
16 minutes. The customer count from this analysis is the basis for the
17 SOMs metric calculations in this report and is subject to change as
18 methodologies are refined

19 **3. Metric Performance for the Reporting Period**

20 [Metric performance for 2025 recorded 1,750 CESO per 100 circuit miles](#)
21 [in HFTD areas, excluding MEDs, where vegetation and equipment failure](#)
22 [were the basic causes \(Figure 2.4-2\).](#)

23 [2025's performance is lower than the prior 3-year average. While](#)
24 [reduced EPSS-related outage impacts due to milder fire-weather were seen](#)
25 [in 2025, particularly impacting HFTD areas, vegetation caused outages also](#)
26 [declined across PG&E's service territory compared to the prior three-year](#)
27 [average.](#)

**FIGURE 2.4-2
CESO PER 100 CIRCUIT MILES (HFTD) (NON-MED)
VEG & EQUIP FAILURE**



Note: The data in this figure is subject to change based on continuing review of prior period information. CESO YTD values from Jan-Jun has been updated since last reporting period.

1 **C. (2.4) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 The 1- and 5-year targets have shifted from being expressed as a range
4 to a single upper target value. This upper target band value remains
5 unchanged while the lower target band has been removed.

6 **2. Target Methodology**

7 The target methodology remains unchanged from the 2025 approach.
8 The target baseline is calculated using a three-year average of past
9 performance from 2022 through 2024. The annual target is then set by
10 applying a 50 percent increase to this baseline, resulting in a single fixed
11 target value. The methodology continues to incorporate historical system
12 performance, anticipated operational measures such as EPSS and DCD

1 impacts, and weather-related variables to maintain consistency in evaluating
2 performance under expected operational and environmental conditions.

- 3 • Historical Data and Trends: Considers past performance data and
4 trends;
- 5 • Benchmarking: Not benchmarkable
- 6 • Regulatory Requirements: California Public Utilities Commission
7 Decision (D.) (D.20-05-053);
- 8 • Appropriate/Sustainable Indicators for Enhanced Oversight and
9 Enforcement: The target for this metric is suitable for Enhanced
10 Oversight and Enforcement as it aligns with unplanned SAIFI target
11 range and accounts for our current work plan and the unknowns of
12 EPSS;
- 13 • Attainable with Known Resources/Work Plan: Yes; and
- 14 • Other Considerations: None.

15 3. 2026 Target

16 The 2026 target is 3,266. PG&E continues to monitor historical and
17 current system performance, year-over-year weather variables, and
18 deployment of operational measures. Targets are evaluated semi-annually
19 and have the potential to be adjusted in each subsequent reporting period.

20 4. 2030 Target

21 The 2030 target is 3,266. PG&E continues to monitor historical and
22 current system performance, year-over-year weather variables, and
23 deployment of operational measures. Targets are evaluated semi-annually
24 and have the potential to be adjusted in each subsequent reporting period.

25 D. (2.4) Progress Towards 1- and 5-Year Target

26 1. Progress Towards the 1-Year Target

27 Performance for 2025 recorded 1750 CESO per 100 circuit miles in
28 HFTD areas, excluding MEDs. This performance is within target range.
29 While weather and EPSS/DCD settings are variables that may impact 2026
30 performance, PG&E expects 2026 performance to remain below the upper
31 target band.

2. Progress Towards the 5-Year Target

PG&E considers current and historical performance, current and future planned work activities, and focuses on continuous improvement, and expects metric performance to remain within the 5-year target.

E. (2.4) Current and Planned Work Activities

PG&E operates a number of programs designed to reduce vegetation- and equipment-caused outages for customers in High Fire Threat Districts. These activities include the following, but are not limited to:

- [Reliability Project Portfolio](#): This portfolio comprises ongoing grid reliability construction, maintenance, and upgrade work that addresses drivers of sustained outage frequency on the system. Activities include equipment installations and replacements, fuse and sectionalizing improvements, and corrective work to address identified condition issues.
- [Circuit Blitz](#): Circuit Blitz activities consist of focused inspections on selected circuits with elevated interruption frequency and prioritizing corrective work to reduce the likelihood of sustained interruptions. These inspections identify vegetation encroachments, equipment deficiencies, and condition issues that can initiate faults.
- [Vegetation Management](#): Vegetation-related faults are a primary contributor to sustained outages. PG&E's vegetation management program focuses on maintaining required clearances and addressing high-risk spans and circuits to reduce vegetation contact and improve accessibility for restoration activities.
- [Asset Replacement \(Overhead, Underground\)](#): PG&E's asset replacement programs address aging infrastructure. Replacing overhead and underground equipment prior to in-service failure reduces unplanned outages and limits the need for complex repairs that can extend restoration timelines.
- [Grid Design and System Hardening](#): Grid design improvements and system hardening measures reduce the frequency of outages by strengthening infrastructure against environmental and operational stressors..
- [Downed Conductor Detection](#): Downed conductor detection technologies reduce the likelihood of extended or repeat interruptions by enabling rapid identification and isolation of faulted segments. Early detection limits

- 1 secondary damage and reduces the potential for multiple customer
2 interruptions.
- 3 • Overhead/Underground Critical Operating Equipment Replacement Work:
4 Replacement and refurbishment of critical operating equipment improves
5 system operability and reliability. Modernized equipment supports more
6 effective sectionalizing and restoration during outage events.
 - 7 • Overhead Fuse Installation: Overhead fuse installations are used to limit the
8 extent of outages by isolating faulted sections of the circuit. Properly
9 coordinated fusing reduces the number of customers affected during outage.
 - 10 • Fault Location, Isolation, and Service Restoration: Fault Location, Isolation,
11 and Service Restoration capabilities support faster identification of fault
12 locations and more efficient switching. These technologies reduce reliance
13 on manual processes and reduce the potential for interruptions on
14 unaffected portions of the circuit.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.1
WIRES DOWN MAJOR EVENT DAYS IN HFTD AREAS
(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.1
WIRES DOWN MAJOR EVENT DAYS IN HFTD AREAS
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 3.1**
4 **WIRES DOWN MAJOR EVENT DAYS IN HFTD AREAS**
5 **(DISTRIBUTION)**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.1) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metric 3.1 – Wires Down Major Event Days
11 (MED) in High Fire Threat District (HFTD) Areas (Distribution) is defined as:

12 *Number of Wires Down events on MED involving overhead (OH)*
13 *primary or secondary distribution circuits divided by total circuit miles of OH*
14 *primary distribution lines x 1,000, in HFTD Areas in a calendar year.*

15 **2. Introduction of Metric**

16 In 2012, Pacific Gas and Electric Company (PG&E) initiated the Electric
17 Wires Down Program, including introduction of the electric wires down
18 metric, to advance PG&E's focus on public safety by reducing the number of
19 electric wire conductors that fail and result in contact with the ground, a
20 vehicle, or other object.

21 This metric is associated with our Failure of Electric Distribution OH
22 Asset Risk and Wildfire Risk, which are part of our 2024 Risk Assessment
23 and Mitigation Phase Report filing.

24 **3. Audit Results**

25 In the Audit Report, Metric 3.1 received a Metric Accuracy Finding of
26 “Significant.” The Other Findings for this metric were “ILIS as the database
27 of record impacts event counts.”¹ *These findings have been resolved.*

28 *With respect to the significant finding, which identified HFTD*
29 *discrepancies, the Outage Foundry Ontology dataset has been joined with*
30 *the latest HFTD version dataset in Foundry to create an outage dataset with*

1 Audit Report, p. 8, Table 1-1.

1 a single HFTD designation for our distribution level outages coming from our
2 Integrated Logging and Information System (ILIS) source system.

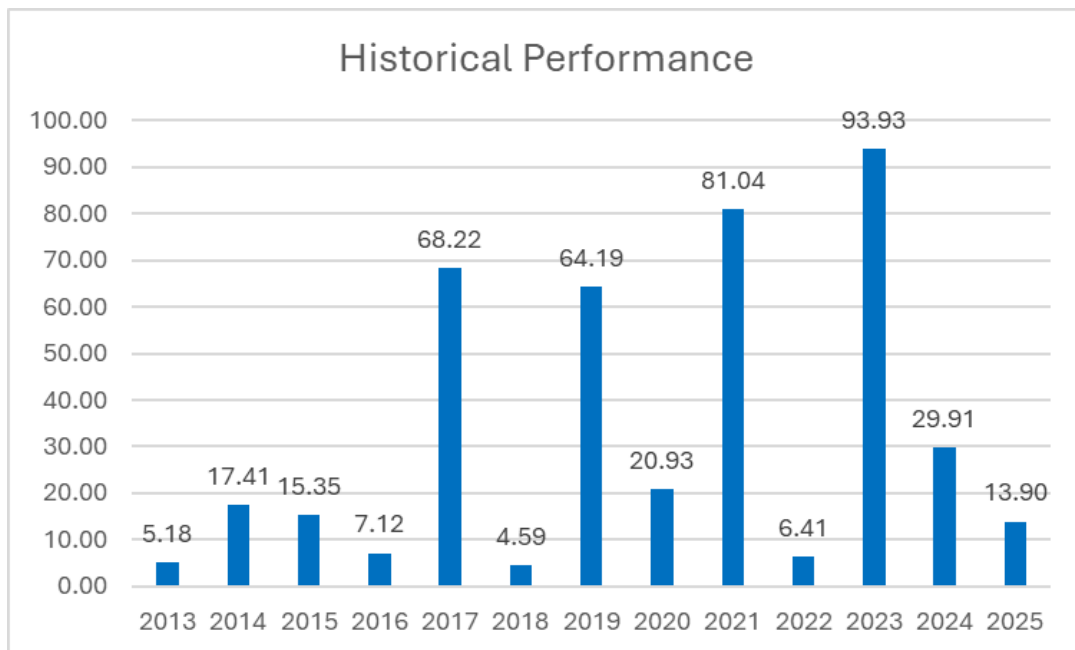
3 With respect to the other finding, ILIS continues to be the database of
4 record. However, this does not impact the ability to report this metric
5 accurately.

6 **B. (3.1) Metric Performance**

7 **1. Historical Data (2013–2025)**

8 Historical performance for wire down events occurring on MEDs within
9 HFTDs covers periods 2013 through 2025 (see Figure 3.1-1 below).
10 Historical metric performance has consistently remained below target
11 thresholds. Additionally, PG&E has tracked and recorded MEDs during the
12 same period (see Table 3.1-2 below). Due to the unpredictability of weather
13 and the inability to forecast the volume of MEDs each year, year-to-year
14 fluctuations in performance make it difficult to discern performance trends.

**FIGURE 3.1-1
HISTORICAL PERFORMANCE
WIRES DOWN HFTD (MED)
(2013- 2025)**



Note: The data in this figure is subject to change based on continuing review of prior period outages.

**TABLE 3.1-1
MAJOR EVENT DAYS TABLE**

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
4	5	10	3	30	7	31	14	25	5	20	5	5

Note: The data in this table is subject to change based on continuing review of prior period outages.

**TABLE 3.1-2
DISTRIBUTION HFTD CIRCUIT MILEAGE TABLE**

Line No.	Distribution HFTD Circuit Mileage	
1	2013-2022 HFTD Circuit Miles (D) ^(a)	25,271
2	2023 HFTD Circuit Miles (D)	25,060
3	2024 HFTD Circuit Miles (D)	24,878
4	2025 HFTD Circuit Miles (D)	24,673
5	2026 HFTD Circuit Miles (D)	24,410

(a) Performance from 2013 2022 uses 2021 HFTD circuit.

1 **2. Data Collection Methodology**

2 PG&E uses the ILIS – Operations Database, to track and count the
3 number of wire down incidents, as well as our Electric Distribution
4 Geographical Information System (EDGIS) to determine if the wire down
5 incident was in an HFTD locations. Although our outage database does not
6 specifically identify precise location of the downed wire, we use the Latitude
7 and Longitude (e.g., Lat/Long) of the device used to isolate the involved
8 electric power line section as a proxy. We also use our EDGIS application
9 to determine if that device (via: Lat/Long information) is in the HFTD
10 (e.g., Tier 2 or Tier 3 location). We have improved our existing processes
11 and transmitted the Lat/Long to our Data & Analytics team to spatially align
12 the wire down events against EDGIS to report accurate HFTD designations.
13 Outage information is entered into ILIS by our electric distribution operators
14 based on information from field personnel and devices such as Supervisory

1 Control and Data Acquisition alarms and SmartMeter™² devices. We last
2 upgraded our outage reporting tools in 2015 and integrated SmartMeter
3 information to identify potential outage reporting errors and to initiate a
4 subsequent review and correction.

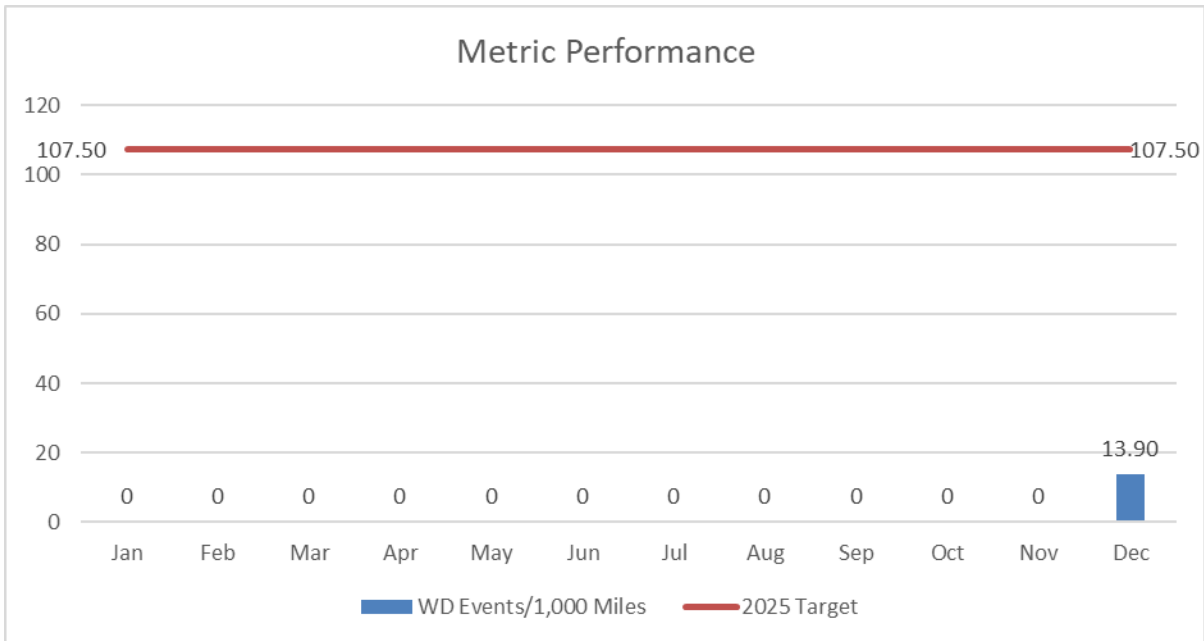
5 PG&E defines the number of wire down events as the number of
6 outages caused by one or more wire down faults. For example, if a single
7 wire down fault causes two protective devices to operate, such as a Line
8 Recloser momentary trip and a downstream fuse burning open, this will be
9 recorded as two separate outages and two wire down events. Alternatively,
10 one protective device operating for a fault caused by multiple spans or
11 phases of wire coming down, will be recorded as one wire down event. This
12 is due to limitations of what can be recorded in the outage logging system.
13 While we are not making any immediate changes to our reporting process,
14 we are evaluating our procedure to determine if our calculation of this metric
15 can be adjusted to address these limitations.

16 **3. Metric Performance for the Reporting Period**

17 Metric performance for this reporting period recorded 13.90 wire down
18 events per 1,000 distribution circuit miles located within HFTD areas,
19 including MEDs (see Figure 3.1-2 below). PG&E's service territory
20 experienced one MED in June and four MEDs in December (see Table 3.1-1
21 above). The number of MEDs experienced during this reporting period
22 highlights the significant year-to-year variability driven by weather conditions
23 and the severity of each event, which impacts the frequency of wire down
24 events.

² SmartMeter is a PG&E registered trademark. All further references to SmartMeters in PG&E's testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

**FIGURE 3.1-2
METRIC PERFORMANCE
WIRES DOWN EVENTS/HFTD CIRCUIT MILES *1000 (MED)
2025**



1 **C. (3.1) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 Directional 1- and 5-year targets have been updated to 107.58. Target
4 methodology remains unchanged since the last report.

5 **2. Target Methodology**

- 6 • Directional Only: Maintain (stay within historical range, and assumes
7 response stays the same in events).

8 Based on the historical performance of this metric, PG&E interprets
9 “Maintain” as staying within two standard deviations from the 10-year
10 average. This equates to an upper limit of 107.58;

- 11 • Historical Data and Trends: This metric is expected to remain within the
12 historical performance levels, but will vary based on the number of
13 MEDs and severity of weather experienced in a year;
14 • Benchmarking: Not available to the best of our knowledge;
15 • Regulatory Requirements: None;
16 • Appropriate/Sustainable Indicators for Enhanced Oversight and
17 Enforcement: The directional target for this metric is suitable for

1 Enhanced Oversight and Enforcement as it states performance will
2 remain within the historical range which accounts for unknown factors
3 which may vary, such as the frequency and severity of weather;

- 4 • Attainable Within Known Resources/Work Plan: Yes, targets are
5 attainable within known resources, however, this metric is impacted by
6 the variability in conditions outside of PG&E's control, such as the
7 volume and severity of weather on MED; and
- 8 • Other Considerations: None.

9 **3. 2026 Target**

10 The updated 2026 target is 107.58. This target is 2-standard deviations
11 above the 10-year average.

12 **4. 2030 Target**

13 The 2030 target is the same as the 1-year target and is expected to
14 maintain within historical performance levels.

15 **D. (3.1) Performance Against Target**

16 **1. Progress Towards the 1-Year Target**

17 Metric performance towards the 1-year target recorded 13.90 wire down
18 events per 1,000 distribution circuit miles within HFTD areas, including
19 MEDs (see Figure 3.1-4 above). PG&E's service territory experienced five
20 MEDs during this period; one MED in June and four MEDs in December
21 (see Table 3.1-2 above). If favorable weather persists, metric performance
22 is expected to remain below the 2026 target threshold.

23 **2. Progress Towards the 5-Year Target**

24 PG&E's commitment to public safety and service reliability drives the
25 initiatives, programs, and work efforts mentioned in Section E below.

26 **E. (3.1) Current and Planned Work Activities**

27 PG&E will continue to execute many ongoing activities to reduce wires
28 down, including the following programs:

- 29 • Covered Conductor Installation – OH hardening helps mitigate transient
30 outages caused by temporary faults, vegetation contact (e.g., eucalyptus
31 bark, palm fronds), wildlife, and mylar balloons. It often includes hardening
32 pole equipment, such as installing covered jumpers and animal protection

1 with covered conductors, reducing exposed energized components and
2 preventing many phase-to-ground outages. This approach can also be
3 applied in buffer zones near HFTD/ High Fire Risk Area (HFRA) boundaries
4 or in non-HFTD/non-HFRA areas with recurring vegetation-related outages
5 that may indicate wildfire risk.

- 6 • Undergrounding of Electric Lines and/or Equipment – PG&E identifies
7 distribution miles in its long-term undergrounding portfolio that share a pole
8 or other structure with transmission. Depending on the conditions in the
9 field, the distribution underbuilt on transmission lines that are identified for
10 hardening may be OH hardened or undergrounded.
- 11 • Remote Grids – Remote grids provide utility service to small loads in remote
12 locations on the outskirts of the distribution system, in lieu of traditional
13 wires. This activity aims to remove distribution feeders and serve customers
14 from a remote grid when that is the most cost-effective way to reduce risk.
- 15 • Line Removal – Line removal is the preferred method for risk reduction and
16 is considered for all system hardening locations where feasible.
- 17 • Downed Conductor Detection (DCD) Devices – DCD is a component of
18 Enhanced Powerline Safety Settings (EPSS) that adds an additional
19 protection element to address fault types not fully mitigated through the
20 EPSS Program.
- 21 • Fuse Saver – Fuse saver installations mitigate against fire risk associated
22 with downed wire events on tap lines through ganged operated
23 de-energization preventing certain types of high impedance faults from
24 occurring.
- 25 • Asset Inspections – PG&E performs detailed visual inspections via aerial
26 method (drone, helicopter, or aerial lift) paired with desktop image review or
27 by an inspector on the ground. These routine inspections seek to visually
28 identify asset conditions that could lead to an ignition.
- 29 • Vegetation Management – The distribution routine patrol program performs
30 inspections on OH electric facilities (excluding service drops) to maintain
31 radial clearance between vegetation and conductors. PG&E's distribution
32 hazard patrol (previously second patrol, tree mortality) program consists of
33 additional proactive inspections conducted in high-risk areas based on a
34 risk-prioritized approach.

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SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.2
WIRES DOWN NON-MAJOR EVENT DAYS IN HFTD AREAS
(DISTRIBUTION)

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5 **(DISTRIBUTION)**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.2) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metric (SOM) 3.2 – Wires Down Non-Major
11 Event Days (Non-MED) in High Fire Threat District (HFTD) Areas
12 (Distribution) is defined as:

13 *Number of Wires Down events on Non-MED involving overhead (OH)*
14 *primary distribution circuits divided by the total circuit miles of OH primary*
15 *distribution lines x 1,000, in HFTD areas, in a calendar year.*

16 **2. Introduction to the Metric**

17 In 2012, Pacific Gas and Electric Company (PG&E or the Company)
18 initiated the Electric Wires Down Program, including introduction of the
19 electric wires down metric, to advance the Company’s focus on public safety
20 by reducing the number of electric wire conductors that fail and result in
21 contact with the ground, a vehicle, or other object.

22 This metric is associated with our Failure of Electric Distribution OH
23 Asset Risk and Wildfire Risk, which are part of our 2024 Risk Assessment
24 and Mitigation Phase Report filing.

25 **3. Audit Results**

26 In the Audit Report, Metric 3.2 received a Metric Accuracy Finding of
27 “Significant.” The Other Findings for this metric were “[Integrated Logging](#)
28 [and Information System \(ILIS\)](#) as the database of record impacts event
29 counts.”¹ [These findings have been resolved.](#)

1 Audit Report, p. 8, Table 1-1.

1 With respect to the significant finding, which identified HFTD
2 discrepancies, the Outage Foundry Ontology dataset has been joined with
3 the latest HFTD version dataset in Foundry to create an outage dataset with
4 a single HFTD designation for our distribution level outages coming from our
5 ILIS source system.

6 With respect to the other finding, ILIS continues to be the database of
7 record. However, this does not impact the ability to report this metric
8 accurately.

9 **B. (3.2) Metric Performance**

10 **1. Historical Data (2013 – 2025)**

11 Historical performance for wire down events occurring on non-MEDs
12 within HFTDs covers 2013 through 2025 (see Figure 3.2-1 below).
13 Historical metric performance has consistently remained below target
14 thresholds.

**FIGURE 3.2-1
HISTORICAL PERFORMANCE
WIRES DOWN HFTD (NON-MED)
(2025)**



Note: The data in this figure is subject to change based on continuing review of prior period outages.

**TABLE 3.2-1
DISTRIBUTION HFTD CIRCUIT MILEAGE TABLE**

Line No.	Distribution HFTD Circuit Mileage	
1	2013-2022 HFTD Circuit Miles (D) ^(a)	25,271
2	2023 HFTD Circuit Miles (D)	25,060
3	2024 HFTD Circuit Miles (D)	24,878
4	2025 HFTD Circuit Miles (D)	24,673
5	2026 HFTD Circuit Miles (D)	24,410

(a) Performance from 2013- 2022 uses 2021 HFTD circuit

1 **2. Data Collection Methodology**

2 PG&E uses its ILIS-Operations Database to track and count the number
3 of wire down incidents, as well as its electric distribution geographical
4 information systems (EDGIS) to determine if the wire down incident was in
5 an HFTD locations. Although the outage database does not specifically
6 identify precise location of the downed wire, the Latitude and Longitude
7 (e.g., Lat/Long) of the device is used to isolate the involved electric power
8 line section as a proxy. We also use our EDGIS application to determine if
9 that device (via: Lat/Long information) is in the HFTD (e.g., Tier 2 or Tier 3
10 location). We have improved our existing processes and transmitted the
11 Lat/Long to our Data & Analytics team to spatially align the wire down
12 events against EDGIS to report accurate HFTD designations. Outage
13 information is entered into ILIS by our electric distribution operators based
14 on information from field personnel and devices such as Supervisory Control
15 and Data Acquisition alarms and SmartMeter™² devices. We last upgraded
16 our outage reporting tools in 2015 and integrated SmartMeter information to
17 identify potential outage reporting errors and to initiate a subsequent review
18 and correction.

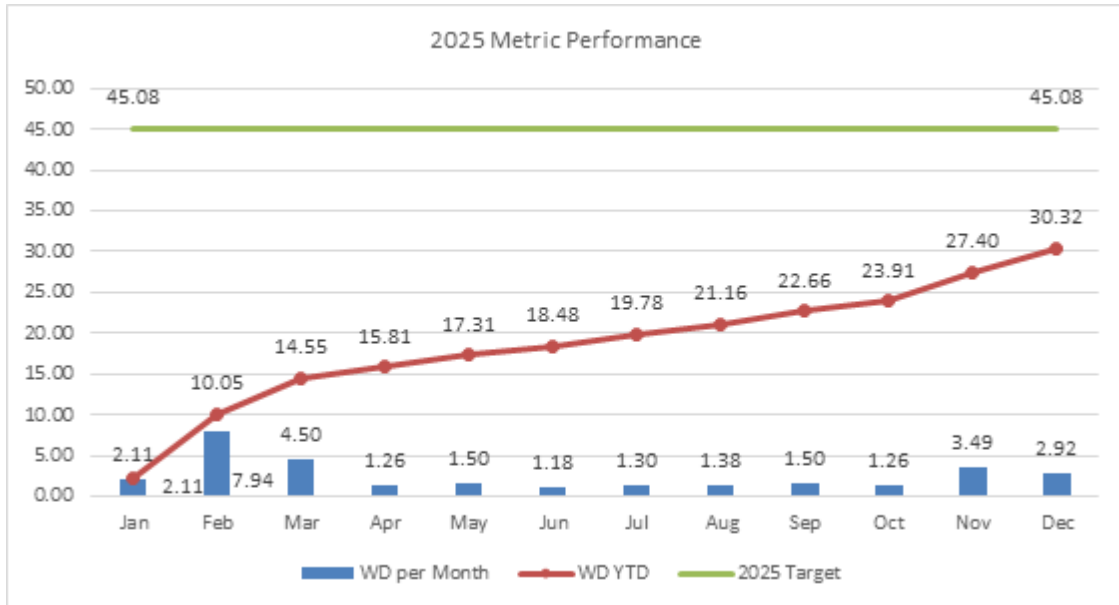
2 SmartMeter is a PG&E registered trademark. All further references to SmartMeters in PG&E’s testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

1 PG&E defines the number of wire down events as the number of
2 outages caused by one or more wire down faults. For example, if a single
3 wire down fault causes two protective devices to operate, such as a Line
4 Recloser momentary trip and a downstream fuse burning open, this will be
5 recorded as two separate outages and two wire down events. Alternatively,
6 one protective device operating for a fault caused by multiple spans or
7 phases of wire coming down, will be recorded as one wire down event. This
8 is due to limitations of what can be recorded in the outage logging system.
9 While we are not making any immediate changes to our reporting process,
10 we are evaluating our procedure to determine if our calculation of this metric
11 can be adjusted to address these limitations.

12 **3. Metric Performance for the Reporting Period**

13 Metric performance for this reporting period recorded 30.32 wire down
14 events per 1,000 distribution circuit miles within HFTD areas, excluding
15 MEDs (see Figure 3.2-2 below). The metric drivers were due to a severe
16 atmospheric river event in February 2025 and another set of atmospheric
17 river events in December 2025 that impacted PG&E service territories. The
18 remainder of the year had favorable weather patterns which resulted in an
19 overall reduction to the 2025 metric.

**FIGURE 3.2-2
METRIC PERFORMANCE
WIRES DOWN EVENTS/1000 MILES HFTD (NON-MED)
2025**



Note: The data in this figure is subject to change based on continuing review of prior period outages. Wires Down events Year-to Date for the month of June has been updated.

C. (3.2) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

Directional 1- and 5-year targets have been updated to 45.12. Target methodology remains unchanged since the last report.

2. Target Methodology

- Directional Only: Maintain (stay within historical range, and assumes response stays the same in events).

Based on the historical performance of this metric, PG&E interprets “Maintain” as staying within 1 standard deviation from the 10-year average. This equates to an upper limit of 45.12;

- Historical Data and Trends: This metric is expected to remain within the historical performance levels, but will vary based on the number of MEDs and severity of weather experienced in a year;
- Benchmarking: Not available to the best of our knowledge;
- Regulatory Requirements: None;

- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: The directional target for this metric is suitable for Enhanced Oversight and Enforcement as it states performance will remain within the historical range which accounts for unknown factors which may vary, such as the frequency and severity of weather;
- Attainable Within Known Resources/Work Plan: Yes, targets are attainable within known resources, however this metric is impacted by the variability in conditions outside of PG&E’s control, such as the weather conditions on non-MEDs; and
- Other Considerations: None.

3. 2026 Target

The updated 2026 target is 45.12. This target is 1-standard deviation above the 10-year average.

4. 2030 Target

The 2030 target is the same as the 1-year target and is expected to maintain within historical performance levels.

D. (3.2) Performance Against Target

1. Progress Towards the 1-Year Target

Metric performance towards the 1-year target recorded 30.32 wire down events per 1,000 distribution circuit miles within HFTD areas, excluding MEDs (see Figure 3.2-2 above). If favorable weather persists, metric performance is expected to remain below the 2026 target threshold.

2. Progress Towards the 5-year Target

PG&E’s commitment to public safety and service reliability drives the initiatives, programs, and work efforts mentioned in Section E below.

E. (3.2) Current and Planned Work Activities

PG&E will continue to execute many ongoing activities to reduce wires down, including the following programs:

- Covered Conductor Installation – Overhead hardening helps mitigate transient outages caused by temporary faults, vegetation contact (e.g., eucalyptus bark, palm fronds), wildlife, and mylar balloons. It often includes hardening pole equipment, such as installing covered jumpers and

1 animal protection with covered conductors, reducing exposed energized
2 components and preventing many phase-to-ground outages. This approach
3 can also be applied in buffer zones near HFTD/High Fire Risk Area (HFRA)
4 boundaries or in non-HFTD/non-HFRA areas with recurring
5 vegetation-related outages that may indicate wildfire risk.

- 6 • Undergrounding of Electric Lines and/or Equipment – PG&E identifies
7 distribution miles in its long-term undergrounding portfolio that share a pole
8 or other structure with transmission. Depending on the conditions in the
9 field, the distribution underbuilt on transmission lines that are identified for
10 hardening may be overhead hardened or undergrounded.
- 11 • Remote Grids – Remote grids provide utility service to small loads in remote
12 locations on the outskirts of the distribution system, in lieu of traditional
13 wires. This activity aims to remove distribution feeders and serve customers
14 from a remote grid when that is the most cost-effective way to reduce risk.
- 15 • Line Removal – Line removal is the preferred method for risk reduction and
16 is considered for all system hardening locations where feasible.
- 17 • Downed Conductor Detection (DCD) Devices –DCD is a component of
18 Enhanced Powerline Safety Settings (EPSS) that adds an additional
19 protection element to address fault types not fully mitigated through the
20 EPSS Program.
- 21 • Fuse Saver – Fuse saver installations mitigate against fire risk associated
22 with downed wire events on tap lines through ganged operated
23 de-energization preventing certain types of high impedance faults from
24 occurring.
- 25 • Asset Inspections – PG&E performs detailed visual inspections via aerial
26 method (drone, helicopter, or aerial lift) paired with desktop image review or
27 by an inspector on the ground. These routine inspections seek to visually
28 identify asset conditions that could lead to an ignition.
- 29 • Vegetation Management – The distribution routine patrol program performs
30 inspections on overhead electric facilities (excluding service drops) to
31 maintain radial clearance between vegetation and conductors. PG&E's
32 distribution hazard patrol (previously second patrol, tree mortality) program
33 consists of additional proactive inspections conducted in high-risk areas
34 based on a risk-prioritized approach.

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6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.3) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metric 3.3 – Wires Down Major Event Days
11 (MED) in High Fire Threat District (HFTD) Areas (Transmission) is defined
12 as:

13 *Number of Wires Down events on MED involving overhead transmission*
14 *circuits divided by total circuit miles of overhead transmission lines x 1,000,*
15 *in HFTD Areas in a calendar year.*

16 **2. Introduction of Metric**

17 This metric is a measure of how Pacific Gas and Electric Company
18 (PG&E or the Company) provides safe and reliable electric services to its
19 customers. It is also a measure of how available PG&E’s electric
20 transmission (ET) grid is to the market for the buying and selling of electricity
21 as managed by the California Independent System Operator (CAISO).

22 This metric is associated with PG&E’s Failure of ET Overhead Asset
23 Risk and Wildfire Risk, which are part of the Company’s 2020 Risk
24 Assessment and Mitigation Phase Report filing.

25 **B. (3.3) Metric Performance**

26 **1. Historical Data (2013 –2025)**

27 Historical performance for this metric covers 2013 through 2025.

28 Although PG&E started measuring wire down incidents in 2012, 2013 was
29 the first full year uniformly measuring the number of transmission wire down
30 events. This metric is normalized by the transmission circuit miles within
31 Tier 2 and Tier 3 HFTDs. The HFTD boundaries are a recent development
32 and were not defined for several years within the historical data timeframe.

1 Hence, for all years prior to and including 2022, PG&E uses
2 5,525.9 overhead transmission circuit miles in Tier 2/3 HFTD areas and
3 assumes any variances in prior years are negligible. Moving forward, HFTD
4 mileage will be refreshed at the beginning of each year. Table 3.3-1
5 provides the HFTD miles used for each year.

**TABLE 3.3-1
HFTD MILES**

<u>Line No.</u>	<u>Year</u>	<u>HFTD Miles</u>
1	Prior to 2023	5525.9
2	2023	5437.7
3	2024	5402.3
4	2025	5377.4

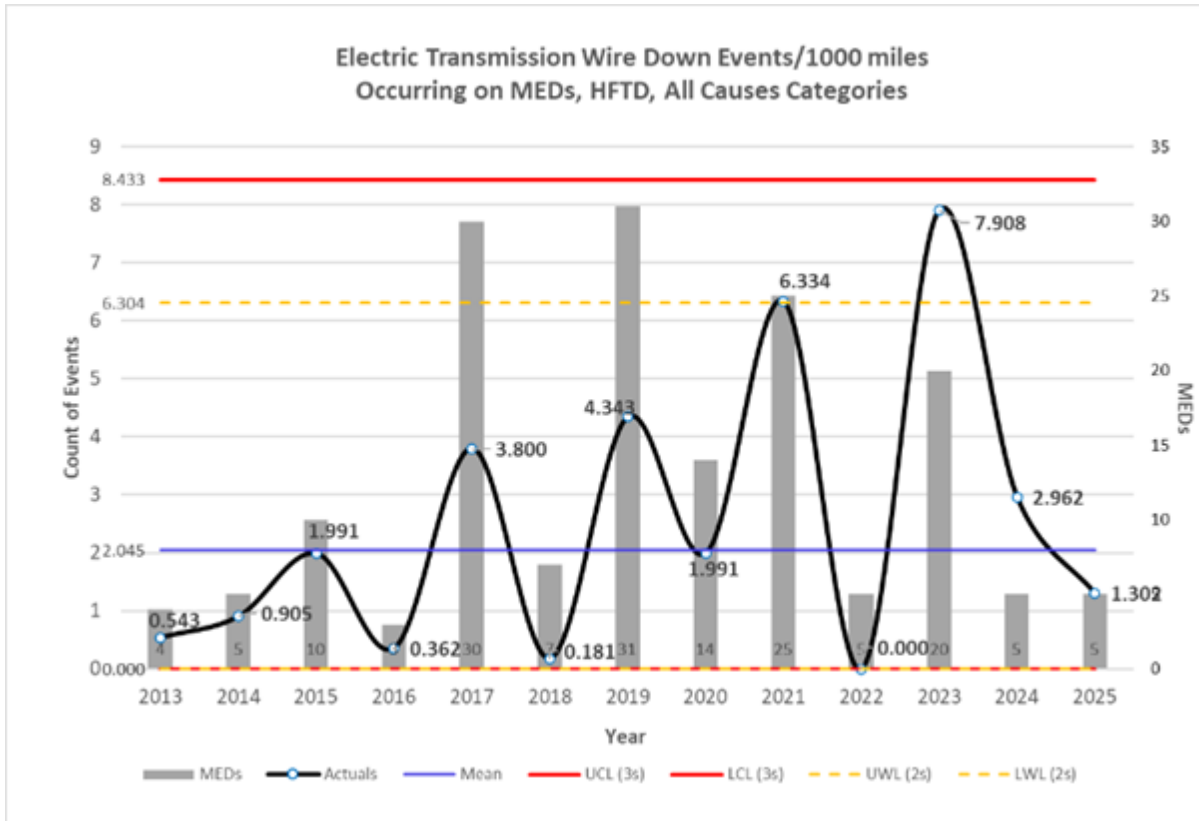
6 **2. Data Collection Methodology**

7 Unplanned ET outages are documented by PG&E’s Transmission
8 Operations Department using its Transmission Operations Tracking and
9 Logging (TOTL) application. If distribution-served customers are affected by
10 a particular transmission wire down event, the data captured in TOTL is
11 merged with respective data from PG&E’s distribution outage reporting
12 application (Integrated Logging Information System) in a separate dataset
13 known as the Transmission Outage database. PG&E uses the Lat/Long of
14 the device used to operate/isolate the involved line section as a proxy,
15 supplemented with findings from fault patrols, and then uses its Electric
16 Transmission Geographic Information System application to determine if
17 that point is in a Tier 2 or Tier 3 HFTD area.

18 **3. Metric Performance for the Reporting Period**

19 Figure 3.3-1 below is a control chart showing historical annual
20 performances through 2025. [For the reporting period, the metric
21 performance is 1.302.](#)

**FIGURE 3.3-1
ELECTRIC TRANSMISSION WIRES DOWN EVENTS OCCURRING
ON MEDS PER 1,000 CIRCUIT MILES HFTD (2013- 2025)**



1 **C. (3.3) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 There are no updates to the directional 1- and 5-Year Targets since last
 4 report, to maintain performance within the historical range, i.e., the target is
 5 to stay below the Upper Control Limit (UCL). The UCL for 2025 (1 Year)
 6 and 2029 (5 Year) is 8.433.

7 **2. Target Methodology**

8 All systems and processes and their outputs exhibit variability. Control
 9 charts help monitor variability and can be used to differentiate common
 10 causes of variability from special causes. Common, or chance, causes are
 11 numerous small causes of variability that are inherent to a system and
 12 operate randomly. Special, or assignable, causes can have relatively large
 13 effects on the process and may lead to a state that is out of statistical
 14 control.

1 PG&E's control charts are set up using a static time window of
2 2013-2022. Using the actual data from those years allows us to calculate
3 the following values that are used in the control charts:

- 4 • Mean: Average value of the metric.
- 5 • Standard Deviation: Amount of variation of the metric calculated by
6 taking the square root of the variance of the dataset.
- 7 • UCL: The maximum value that can be attributed to natural fluctuations
8 calculated by mean plus three standard deviations.
- 9 • Lower Control Limit (LCL): The minimum value that can be attributed to
10 natural fluctuations calculated by mean minus three standard deviations.
- 11 • Upper Warning Limit: The warning value that should raise a flag to take
12 a proactive response to prevent the metric from approaching the UCL
13 calculated by mean plus two standard deviations.
- 14 • Lower Warning Limit: The warning value that should raise a flag to take
15 a proactive response to prevent the metric from approaching the LCL
16 calculated by mean minus two standard deviations.

17 The probability that a point falls above the UCL, which for most control
18 chart designs, is approximately 0.00135 and an indicator of significant
19 process degradation if only common causes are operating. It is therefore
20 unlikely to have performance fall beyond the control limits when no special
21 cause is operating.

22 To establish the 1-Year and 5-Year targets, PG&E considered the
23 following:

- 24 • Historical Data and Trends: 1-Year and 5-Year Targets are set to
25 maintain performance within a three-standard deviation range using the
26 available historical data. A three-standard deviation remains consistent
27 with other ET external report filings with the CAISO.
- 28 • Benchmarking: Not available to best of our knowledge;
- 29 • Regulatory Requirements: None;
- 30 • Appropriate/Sustainable Indicators for Enhanced Oversight and
31 Enforcement: The directional target for this metric is suitable for
32 Enhanced Oversight and Enforcement as it states metric performance
33 will remain in historical range;

- Attainable Within Known Resources/Work Plan: Yes, this metric is attainable within known resources, however this metric is impacted by the variability in conditions outside of PG&E's control, such as the severity of inclement weather on MED; and
- Other Considerations: None.

3. 2026 Target

Not to exceed 8.433 (UCL), which represents maintaining within a 3-standard deviation historical range.

4. 2030 Target

Not to exceed 8.433 (UCL), which represents maintaining within a three-standard deviation historical range.

D. (3.3) Performance Against Target

1. Progress Towards the 1-Year Target

In 2025, PG&E experienced seven wire down events per 1,000 circuit miles in HFTDs on MEDs resulting in a performance of 1.302.

2. Progress Towards the 5-Year Target

As discussed in Section E below, PG&E is deploying a number of programs to maintain or improve long-term performance of this metric to meet the Company's 5-year directional performance target.

E. (3.3) Current and Planned Work Activities

Wire down events can be caused by a variety of factors, including, but not limited to asset failure, third-party contact, or vegetation contact. The following work activities may provide future resiliency for certain wire down event causes, though the effectiveness of the work is dependent upon the circumstances of the wire down event (e.g., new assets may still be prone to a wire down event that occur due to extreme weather events outside of standard design guidance).

- Pole/Tower Replacement and Reinforcements – Transmission Pole/Tower Replacement Program addresses remediation, adjustments, or installations of new equipment to improve or replace existing transmission wood poles and towers.
- Traditional Overhead Hardening – Traditional overhead hardening of transmission conductor can occur through asset replacement and

1 maintenance programs. These activities include Dispersed Conductor
2 (Splice) Hardening and Conductor Segment Replacements

- 3 • Asset Inspections – PG&E performs detailed visual inspections via aerial
4 method (drone, helicopter, or aerial lift) paired with desktop image review or
5 by an inspector on the ground. These routine inspections seek to visually
6 identify asset conditions that could lead to an ignition.
- 7 • Vegetation Management – PG&E’s Transmission Routine Patrol Program
8 spans all transmission lines across PG&E’s service territory and consists of
9 several different methods for inspecting vegetation in proximity to
10 transmission facilities. The program scope is organized into North American
11 Electric Reliability Corporation (NERC) and non-NERC inspections.

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3 **CHAPTER 3.4**
4 **WIRES DOWN NON-MAJOR EVENT DAYS IN HFTD AREAS**
5 **(TRANSMISSION)**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.4) Introduction**

9 **1. Metric Definition**

10 Safety and Operational Metric (SOM) 3.4 – Wires Down Non-Major
11 Even Days in High Fire Threat District (HFTD) Areas (Transmission) is
12 defined as:

13 *Number of Wires Down events on Non-Major Event Days (MED)*
14 *involving overhead transmission circuits divided by total circuit miles of*
15 *overhead transmission lines x 1,000, in HFTD Areas in a calendar year.*

16 **2. Introduction of Metric**

17 This metric is a measure of how Pacific Gas and Electric Company
18 (PG&E or the Company) provides safe and reliable electric services to its
19 customers. It is also a measure of how available PG&E's Electric
20 Transmission (ET) grid is to the market for the buying and selling of
21 electricity as managed by the California Independent System Operator
22 (CAISO).

23 This metric is associated with PG&E's Failure of ET Overhead Asset
24 Risk and Wildfire Risk, which are part of the Company's 2020 Risk
25 Assessment and Mitigation Phase Report filing.

26 **B. (3.4) Metric Performance**

27 **1. Historical Data (2013 –2025)**

28 Historical performance for this metric cover 2013 through 2025.

29 Although PG&E started measuring wire down events in 2012, 2013 was the
30 first full year uniformly measuring the number of transmission wire down
31 incidents. This metric is normalized by the transmission circuit miles within
32 Tier 2 and Tier 3 HFTDs. The HFTD boundaries are a recent development

1 and were not defined for several years within the historical data timeframe.
 2 Hence, for all years prior to and including 2022, PG&E uses
 3 5,525.9 overhead transmission circuit miles in Tier 2/3 HFTD areas and
 4 assumes any variances in prior years are negligible. Moving forward, HFTD
 5 mileage will be refreshed at the beginning of each year. Table 3.4-1
 6 provides the HFTD miles used for each year.

**TABLE 3.4-1
 HFTD MILES**

Line No.	Year	HFTD Miles
1	Prior to 2023	5525.9
2	2023	5437.7
3	2024	5402.3
4	2025	5377.4

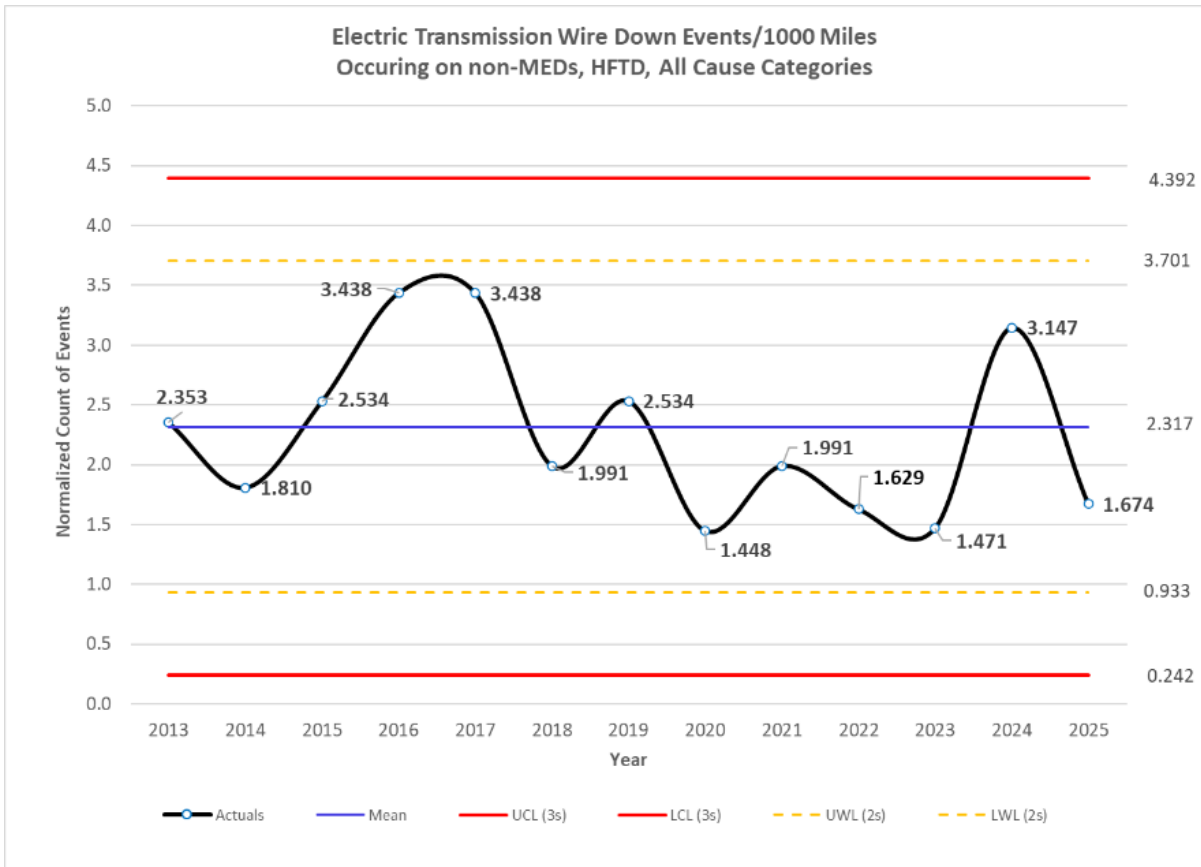
7 **2. Data Collection Methodology**

8 Unplanned ET outages are documented by PG&E’s Transmission
 9 Operations Department using its Transmission Operations Tracking &
 10 Logging (TOTL) application. If distribution-served customers are affected by
 11 a particular transmission wire down event, the data captured in TOTL is
 12 merged with respective data from PG&E’s distribution outage reporting
 13 application (Integrated Logging Information System) in a separate dataset
 14 known as the Transmission Outage database. PG&E uses the Lat/Long of
 15 the device used to operate/isolate the involved line section as a proxy,
 16 supplemented with findings from fault patrols, and then uses its Electric
 17 Transmission Geographic Information System application to determine if
 18 that point is in a Tier 2 or Tier 3 HFTD area.

19 **3. Metric Performance for the Reporting Period**

20 Figure 3.4-1 below is a control chart showing historical annual
 21 performances through 2025. [For the reporting period, the metric](#)
 22 [performance is 1.674.](#)

**FIGURE 3.4-1
ELECTRIC TRANSMISSION WIRES DOWN EVENTS
OCCURRING ON NON-MEDS PER 1,000 CIRCUIT MILES HFTD
2013- 2025**



1 **C. (3.4) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 There are no updates to the directional 1- and 5-Year Targets since last
 4 report, to maintain performance within the historical range, i.e., the target is
 5 to stay below the Upper Control Limit (UCL). The UCL for 2025 (1 Year)
 6 and 2029 (5 Year) is 4.392.

7 **2. Target Methodology**

8 All systems and processes and their outputs exhibit variability. Control
 9 charts help monitor variability and can be used to differentiate common
 10 causes of variability from special causes. Common, or chance, causes are
 11 numerous small causes of variability that are inherent to a system and
 12 operate randomly. Special, or assignable, causes can have relatively-large

1 effects on the process and may lead to a state that is out of statistical
2 control.

3 PG&E's control charts are set up using a static time window of
4 2013-2022. Using the actual data from those years allows us to calculate
5 the following values that are used in the control charts:

- 6 • Mean: Average value of the metric.
- 7 • Standard Deviation: Amount of variation of the metric calculated by
8 taking the square root of the variance of the dataset.
- 9 • Upper Control Limit (UCL): The maximum value that can be attributed
10 to natural fluctuations calculated by mean plus 3 standard deviations.
- 11 • Lower Control Limit (LCL): The minimum value that can be attributed to
12 natural fluctuations calculated by mean minus 3 standard deviations.
- 13 • Upper Warning Limit (UWL): The warning value that should raise a flag
14 to take a proactive response to prevent the metric from approaching the
15 UCL calculated by mean plus 2 standard deviations.
- 16 • Lower Warning Limit (LWL): The warning value that should raise a flag
17 to take a proactive response to prevent the metric from approaching the
18 LCL calculated by mean minus 2 standard deviations.

19 The probability that a point falls above the UCL, which for most control
20 chart designs, is approximately 0.00135 and an indicator of significant
21 process degradation if only common causes are operating. It is therefore
22 unlikely to have performance fall beyond the control limits when no special
23 cause is operating.

24 To establish the 1-Year and 5-Year targets, PG&E considered the
25 following:

- 26 • Historical Data and Trends: 1-Year and 5-Year Targets are set to
27 maintain performance within a 3-standard deviation range using the
28 available historical data. A 3-standard deviation remains consistent with
29 other ET external report filings with the CAISO.
- 30 • Benchmarking: Not available to the best of our knowledge;
- 31 • Regulatory Requirements: None;
- 32 • Appropriate/Sustainable Indicators for Enhanced Oversight and
33 Enforcement: The target for this metric is suitable for Enhanced

Oversight and Enforcement as it suggests that future results will remain within the historic performance levels;

- Attainable Within Known Resources/Work Plan: Metric targets are attainable within known resources, however this metric is impacted by the variability in conditions outside of PG&E's control, such as the severity of inclement weather on days that do not register as MEDs; and
- Other Considerations: None.

3. 2026 Target

Not to exceed 4.392 (UCL), which represents maintaining within a 3-standard deviation range.

4. 2030 Target

Not to exceed 4.392 (UCL), which represents maintaining within a 3-standard deviation range.

D. (3.4) Performance Against Target

1. Progress Towards the 1-year Target

In 2025, PG&E experienced nine wires down events per 1,000 circuit miles in HFTDs on non-MEDs resulting in a performance of 1.674.

2. Progress Towards the 5-year Target

As discussed in Section E below, PG&E is deploying a number of programs to maintain or improve long-term performance of this metric to meet the Company's 5-year performance target.

E. (3.4) Current and Planned Work Activities

Wire down events can be caused by a variety of factors, including, but not limited to asset failure, third-party contact, or vegetation contact. The following work activities may provide future resiliency for certain wire down event causes, though the effectiveness of the work is dependent upon the circumstances of the wire down event (e.g., new assets may still be prone to a wire down event that occur due to extreme weather events outside of standard design guidance).

- Pole/Tower Replacement and Reinforcements – Transmission Pole/Tower Replacement Program addresses remediation, adjustments,

1 or installations of new equipment to improve or replace existing
2 transmission wood poles and towers.

- 3 • Traditional Overhead Hardening – Traditional overhead hardening of
4 transmission conductor can occur through asset replacement and
5 maintenance programs. These activities include Dispersed Conductor
6 (Splice) Hardening and Conductor Segment Replacements
- 7 • Asset Inspections – PG&E performs detailed visual inspections via
8 aerial method (drone, helicopter, or aerial lift) paired with desktop image
9 review or by an inspector on the ground. These routine inspections
10 seek to visually identify asset conditions that could lead to an ignition.
- 11 • Vegetation Management – PG&E’s Transmission Routine Patrol
12 Program spans all transmission lines across PG&E’s service territory
13 and consists of several different methods for inspecting vegetation in
14 proximity to transmission facilities. The program scope is organized into
15 North American Electric Reliability Corporation (NERC) and non-NERC
16 inspections.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.5
WIRES DOWN RED FLAG WARNING DAYS IN HFTD AREAS
(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 3.5**
4 **WIRES DOWN RED FLAG WARNING DAYS IN HFTD AREAS**
5 **(DISTRIBUTION)**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.5) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metric (SOM) 3.5 – Wires Down Red Flag
11 Warning (RFW) Days in High Fire Threat District (HFTD) Areas (Distribution)
12 is defined as:

13 *Number of Wires Down events in HFTD Areas on RFW Days involving*
14 *overhead (OH) primary distribution circuits divided by RFW Distribution*
15 *Circuit-Mile Days in HFTD Areas, in a calendar year.*

16 **2. Introduction of Metric**

17 This metric measures the number of distribution wire down events
18 located in the Tier 2 and Tier 3 HFTD areas that occurred on RFW Days and
19 is divided by sum of days and line miles (of the Tier 2 and Tier 3 HFTD OH
20 distribution line miles involved on each RFW Day).

21 In 2012, Pacific Gas and Electric Company (PG&E or the Company)
22 initiated the Electric Wires Down Program, including introduction of the
23 electric wires down metric, to advance the Company’s focus on public safety
24 by reducing the number of electric wire conductors that fail and result in
25 contact with the ground, a vehicle, or other object.

26 This metric is associated with our Failure of Electric Distribution OH
27 Asset Risk and Wildfire Risk, which are part of our 2024 Risk Assessment
28 and Mitigation Phase Report (RAMP) filing.

1 **3. Audit Results**

2 In the Audit Report, Metric 3.5 received a Metric Accuracy Finding of
3 “Significant.” The Other Findings for this metric were “ILIS as the database
4 of record impacts event counts.”¹ *These findings have been resolved.*

5 *With respect to the significant finding, which identified HFTD*
6 *discrepancies, the Outage Foundry Ontology dataset has been joined with*
7 *the latest HFTD version dataset in Foundry to create an outage dataset with*
8 *a single HFTD designation for our distribution level outages coming from our*
9 *Integrated Logging and Information System (ILIS) source system.*

10 *With respect to the other finding, ILIS continues to be the database of*
11 *record. However, this does not impact the ability to report this metric*
12 *accurately.*

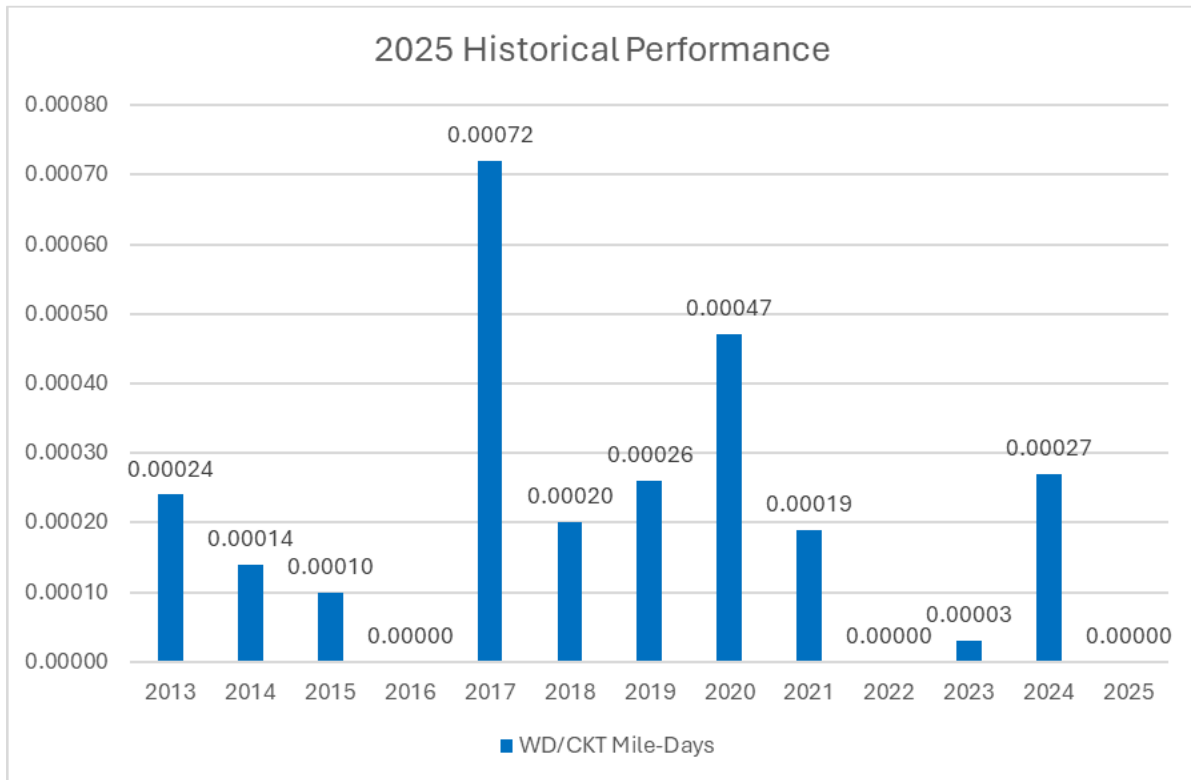
13 **B. (3.5) Metric Performance**

14 **1. Historical Data (2013 –2025)**

15 Historical performance for wire down events on RFW Days within HFTD
16 areas cover periods 2013 through 2025 (see Figure 3.5-1 below). Historical
17 metric performance has consistently remained below target thresholds.

¹ Audit Report, p. 8, Table 1-1.

**FIGURE 3.5-1
HISTORICAL PERFORMANCE
WIRES DOWN HFTD (RFW DAYS)
(2013- 2025)**



Note: The data in this figure is subject to change based on continuing review of prior period outages.

2. Data Collection Methodology

PG&E uses its ILIS – Operations Database to track and count the number of wire down incidents, as well as its Electric Distribution Geographical Information System (EDGIS) to determine if the wire down incident was in an HFTD locations. Although the outage database does not specifically identify precise location of the downed wire, the Latitude and Longitude (e.g., Lat/Long) of the device is used to isolate the involved electric power line section as a proxy. We also use our EDGIS application to determine if that device (via: Lat/Long information) is in the HFTD (e.g., Tier 2 or Tier 3 location). We have improved our existing processes and transmitted the Lat/Long to our Data & Analytics team to spatially align the wire down events against EDGIS to report accurate HFTD designations. Outage information is entered into ILIS by our electric distribution operators

1 based on information from field personnel and devices such as Supervisory
2 Control and Data Acquisition alarms and SmartMeter™² devices. We last
3 upgraded our outage reporting tools in 2015 and integrated SmartMeter
4 information to identify potential outage reporting errors and to initiate a
5 subsequent review and correction.

6 PG&E defines the number of wire down events as the number of
7 outages caused by one or more wire down faults. For example, if a single
8 wire down fault causes two protective devices to operate, such as a Line
9 Recloser momentary trip and a downstream fuse burning open, this will be
10 recorded as two separate outages and two wire down events. Alternatively,
11 one protective device operating for a fault caused by multiple spans or
12 phases of wire coming down, will be recorded as one wire down event. This
13 is due to limitations of what can be recorded in the outage logging
14 system. While we are not making any immediate changes to our reporting
15 process, we are evaluating our procedure to determine if our calculation of
16 this metric can be adjusted to address these limitations.

17 PG&E's meteorology group maintains a database tracking RFW dates,
18 time, and involved areas and determines RFW Circuit Miles Days as follows:

- 19 • The National Weather Service (NWS) will issue a RFW and their
20 associated polygons under specific polygon/shapefiles called Fire
21 Zones.
- 22 • PG&E's geographic information system team has calculated all OH
23 Distribution and Transmission lines for all the Fire Zone shapefile
24 boundaries that intersect PG&E territory. For each NWS Fire Zone
25 PG&E has the number of OH line miles for Distribution and
26 Transmission and the number of OH line miles for Transmission, which
27 is then also split into the specific HFTD and non HFTD tiers and zones.
- 28 • Meteorology then compiles all the archived RFW shapefiles for
29 California, and from all the RFW events, determines which zones there
30 was a RFW under and the duration of time it lasted.

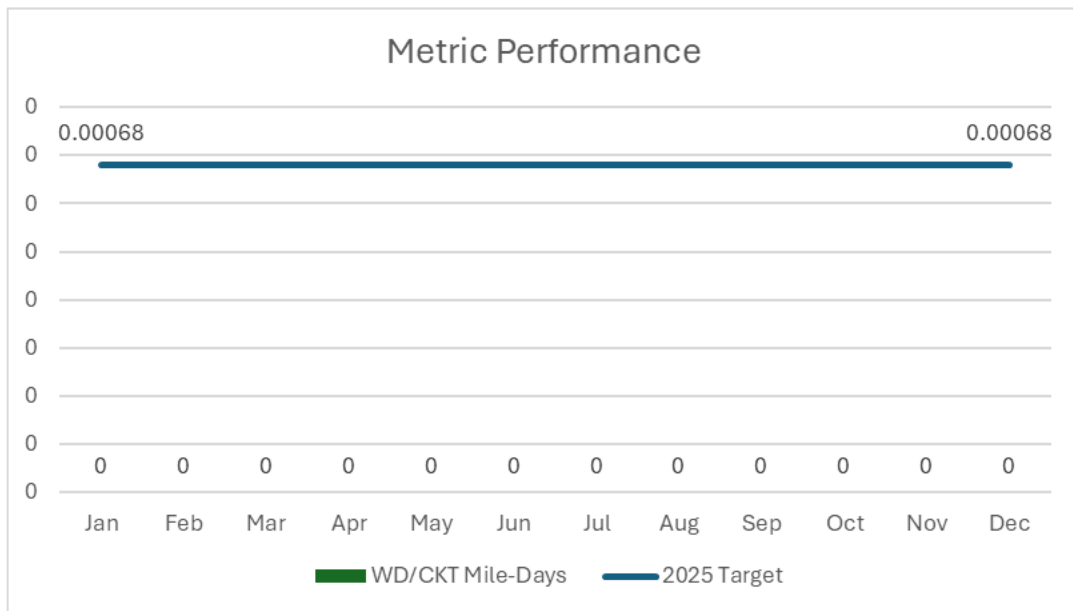
2 SmartMeter is a PG&E registered trademark. All further references to SmartMeters in PG&E's testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

- RFW Circuit Mile Days= RFW days x Circuit line miles.

3. Metric Performance for the Reporting Period

Metric performance for this reporting period recorded zero wire down events in HFTD areas on RFW Days involving OH primary distribution circuits (See Figure 3.5-2 below). PG&E service areas experienced favorable weather patterns in 2025.

**FIGURE 3.5-2
METRIC PERFORMANCE
WIRES DOWN EVENTS/RFW CIRCUIT MILE-DAYS HFTD
2025**



C. (3.5) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

Directional 1- and 5-year targets have been updated to 0.00069. Target methodology remains unchanged since the last report.

2. Target Methodology

- Directional Only: Maintain (stay within historical range, and assumes response stays the same in events);

Based on the historical performance of this metric, PG&E interprets “Maintain” as staying within two standard deviations from the 10-year average. This equates to an upper limit of 0.00069;

- 1 • Historical Data and Trends: This metric is expected to remain within the
2 historical performance levels, but will vary based on the number of
3 RFWs and severity of weather experienced in a year;
- 4 • Benchmarking: Not available to the best of our knowledge;
- 5 • Regulatory Requirements: None;
- 6 • Appropriate/Sustainable Indicators for Enhanced Oversight and
7 Enforcement: The directional target for this metric is suitable for
8 Enhanced Oversight and Enforcement as it states performance will
9 remain within the historical range which accounts for unknown factors
10 which may vary, such as the frequency and severity of weather;
- 11 • Attainable Within Known Resources/Work Plan: Yes, targets are
12 attainable within known resources, however this metric is impacted by
13 the variability in conditions outside of PG&E's controls, such as the
14 volume and severity of weather on RFWs;
- 15 • Other Considerations: None.

16 3. 2026 Target

17 The updated 2026 target is 0.00069. This target maintains within
18 historical performance levels.

19 4. 2030 Target

20 The 2030 target is the same as the 1-year target and is expected to
21 maintain within historical performance levels.

22 D. (3.5) Performance Against Target

23 1. Progress Towards the 1-year Target

24 Metric performance towards the 1-year target recorded zero wire down
25 events on RFW Days involving OH primary distribution circuits (See
26 Figure 3.5-2 above). If favorable weather persists, metric performance is
27 expected to remain below the 2026 target threshold.

28 2. Progress Towards the 5-year Target

29 PG&E's commitment to public safety and service reliability drives the
30 initiatives, programs, and work efforts mentioned in Section E below.

1 **E. (3.5) Current and Planned Work Activities**

2 PG&E will continue to execute many ongoing activities to reduce wires
3 down, including the following programs:

- 4 • Covered Conductor Installation – Overhead hardening helps mitigate
5 transient outages caused by temporary faults, vegetation contact
6 (e.g., eucalyptus bark, palm fronds), wildlife, and mylar balloons. It often
7 includes hardening pole equipment, such as installing covered jumpers and
8 animal protection with covered conductors, reducing exposed energized
9 components and preventing many phase-to-ground outages. This approach
10 can also be applied in buffer zones near HFTD/HFRA boundaries or in
11 non-HFTD/non-HFRA areas with recurring vegetation-related outages that
12 may indicate wildfire risk.
- 13 • Undergrounding of Electric Lines and/or Equipment – PG&E identifies
14 distribution miles in its long-term undergrounding portfolio that share a pole
15 or other structure with transmission. Depending on the conditions in the
16 field, the distribution underbuilt on transmission lines that are identified for
17 hardening may be overhead hardened or undergrounded.
- 18 • Remote Grids – Remote grids provide utility service to small loads in remote
19 locations on the outskirts of the distribution system, in lieu of traditional
20 wires. This activity aims to remove distribution feeders and serve customers
21 from a remote grid when that is the most cost-effective way to reduce risk.
- 22 • Line Removal – Line removal is the preferred method for risk reduction and
23 is considered for all system hardening locations where feasible.
- 24 • Downed Conductor Detection (DCD) Devices –DCD is a component of
25 Enhanced Powerline Safety Settings (EPSS) that adds an additional
26 protection element to address fault types not fully mitigated through the
27 EPSS Program.
- 28 • Fuse Saver – Fuse saver installations mitigate against fire risk associated
29 with downed wire events on tap lines through ganged operated
30 de-energization preventing certain types of high impedance faults from
31 occurring.
- 32 • Asset Inspections – PG&E performs detailed visual inspections via aerial
33 method (drone, helicopter, or aerial lift) paired with desktop image review or

1 by an inspector on the ground. These routine inspections seek to visually
2 identify asset conditions that could lead to an ignition.

- 3 • Vegetation Management – The distribution routine patrol program performs
4 inspections on overhead electric facilities (excluding service drops) to
5 maintain radial clearance between vegetation and conductors. PG&E’s
6 distribution hazard patrol (previously second patrol, tree mortality) program
7 consists of additional proactive inspections conducted in high-risk areas
8 based on a risk-prioritized approach.

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5 **(TRANSMISSION)**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.6) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metric 3.6 – Wires Down Red Flag Warning
11 Days in High Fire Threat District (HFTD) Areas (Transmission) is defined as:
12 *Number of Wires Down events in HFTD Areas on Red Flag Warning*
13 *(RFW) Days involving overhead (OH) transmission circuits divided by RFW*
14 *Transmission Circuit-Mile Days in HFTD Areas, in a calendar year.*

15 **2. Introduction of Metric**

16 This metric measures the count of Transmission Wire Down events
17 occurring on RFW Days and provides a partial indicator for electric system
18 safety and overall electric service reliability for end-use customers.

19 This metric is associated with Pacific Gas and Electric Company’s
20 (PG&E or the Company) Failure of Electric Transmission Overhead Asset
21 Risk and Wildfire Risk, which are part of the Company’s 2020 Risk
22 Assessment and Mitigation Phase Report filing.

23 **B. (3.6) Metric Performance**

24 **1. Historical Data (2013 – 2025)**

25 Historical data for this metric covers 2013 through 2025. Although
26 PG&E started measuring wire down events in 2012, 2013 was the first full
27 year, uniformly measuring the number of transmission wire down incidents.
28 When calculating this metric, both the HFTD OH line miles and number of
29 wires down events are measured based on the area subjected by each
30 specific RFW Day event and summed for each specific year.

31 The HFTD boundaries are a recent development and were not defined
32 for several years. Hence, for all years prior to and including 2022, PG&E

1 uses 5,525.9 OH transmission circuit miles in Tier 2/3 HFTD areas and
 2 assumes any variances in prior years are negligible. Moving forward, HFTD
 3 mileage will be refreshed at the beginning of each year. Table 3.6-1
 4 provides the HFTD miles used for each year.

**TABLE 3.6-1
 HFTD MILES**

Line No.	Year	HFTD Miles
1	Prior to 2023	5525.9
2	2023	5437.7
3	2024	5402.3
4	2025	5377.4

5 **2. Data Collection Methodology**

6 Unplanned ET outages are documented by PG&E’s Transmission
 7 Operations Department using its Transmission Operations Tracking &
 8 Logging (TOTL) application. If distribution-served customers are affected by
 9 a particular transmission wire down event, the data captured in TOTL is
 10 merged with respective data from PG&E’s distribution outage reporting
 11 application (Integrated Logging Information System) in a separate dataset
 12 known as the Transmission Outage database. PG&E uses the Lat/Long of
 13 the device used to operate/isolate the involved line section as a proxy,
 14 supplemented with findings from fault patrols, and then uses its Electric
 15 Transmission Geographic Information System application to determine if
 16 that point is in a Tier 2 or Tier 3 HFTD area.

17 The meteorology group maintains a database with the RFW days/time
 18 and involved areas and determines RFW Circuit Miles Days as follows:

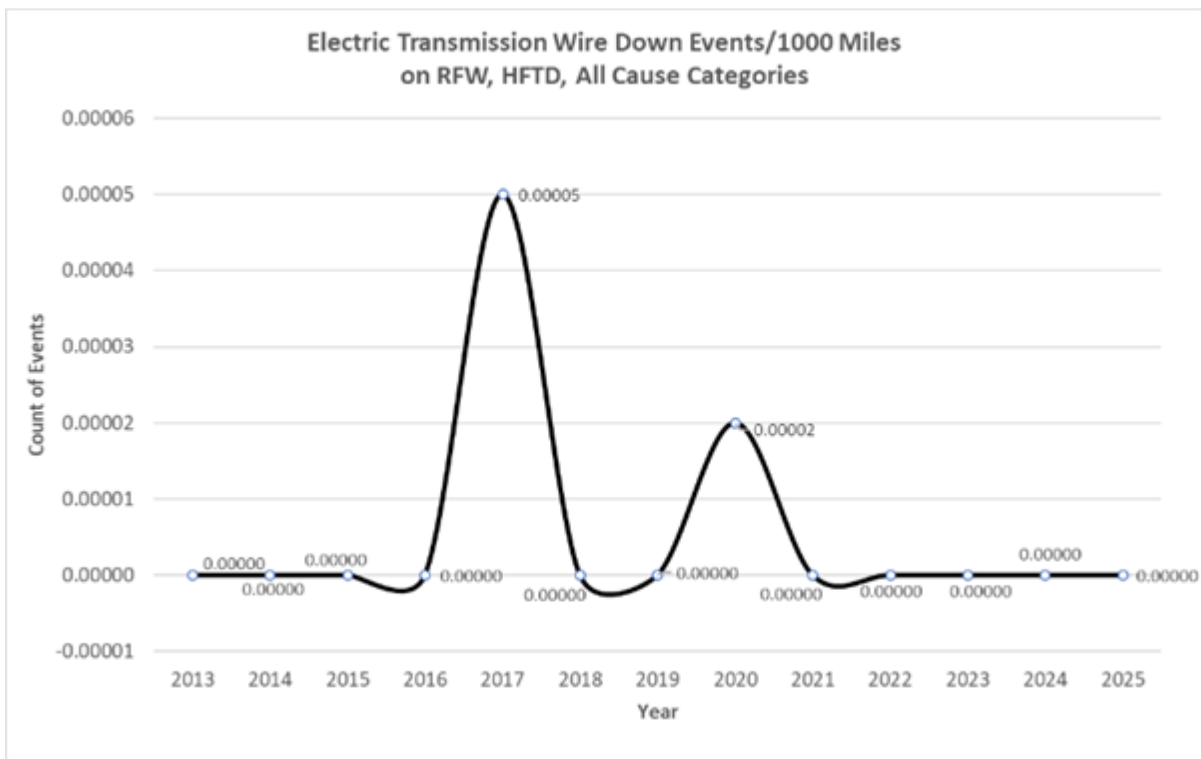
- 19 • The National Weather Service (NWS) will issue a RFW and their
 20 associated polygons under specific polygon/shapefiles called Fire
 21 Zones;
- 22 • PG&E’s geographic information system team has calculated all OH
 23 Distribution and Transmission lines for all of the Fire Zone shapefile
 24 boundaries that intersect PG&E territory. For each NWS Fire Zone
 25 PG&E has the number of OH line miles for Distribution and

- 1 Transmission and the number of OH line miles for Transmission, which
 2 is then also split into the specific HFTD and non HFTD tiers and zones;
 3 • Meteorology then compiles all the archived RFW shapefiles for
 4 California, and from all the RFW events, determines which zones there
 5 was a RFW under and the duration of time it lasted; and
 6 • RFW Circuit Mile Days= RFW days x Circuit line miles.

7 **3. Metric Performance for the Reporting Period**

8 Figure 3.6-1 below shows the historical annual performance of
 9 transmission wire down events on RFW days per circuit mile days through
 10 for 2025. There were zero transmission wires down events on RFW days
 11 for 2025.

**FIGURE 3.6-1
 ELECTRIC TRANSMISSION
 WIRES DOWN INCIDENTS PER RFW/CIRCUIT MILE-DAYS (2013- 2025)**



1 **C. (3.6) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 There are no updates to the directional 1- and 5-Year Targets since last
4 report and are set maintain performance within the historical range.

5 **2. Target Methodology**

- 6 • Directional Only: Maintain (stay within historical range, and assumes
7 response stays the same in events);

8 Note that there has not been enough historic electric transmission
9 (ET) wire down events on RFW days to establish a target based on prior
10 performance.

- 11 • Benchmarking: Not available to the best of our knowledge;
12 • Regulatory Requirements: None;
13 • Appropriate/Sustainable Indicators for Enhanced Oversight and
14 Enforcement: The directional target for this metric is suitable for
15 Enhanced Oversight and Enforcement as it suggests performance will
16 remain within the historical range;
17 • Attainable Within Known Resources/Work Plan: Unknown, however this
18 metric is impacted by the variability in conditions outside of PG&E's
19 control, such as the severity of weather on RFWs; and
20 • Other Considerations: None.

21 **3. 2026 Target**

22 Maintain performance within historical range.

23 **4. 2030 Target**

24 Maintain performance within historical range.

25 **D. (3.6) Performance Against Target**

26 **1. Progress Towards the 1-Year Target**

27 As demonstrated in Figure 3.6-1, PG&E experienced zero transmission
28 wires down events on RFW Days which is consistent with Company's 1-year
29 directional target.

1 **2. Progress Towards the 5-Year Target**

2 As discussed in Section E below, PG&E is deploying a number of
3 programs to maintain or improve long-term performance of this metric to
4 align with the Company’s 5-year directional performance target.

5 **E. (3.6) Current and Planned Work Activities**

6 Wire down events can be caused by a variety of factors, including but not
7 limited to asset failure, third-party contact, or vegetation contact. The following
8 work activities may provide future resiliency for certain wire down event causes,
9 though the effectiveness of the work is dependent upon the circumstances of the
10 wire down event (e.g., new assets may still be prone to a wire down event that
11 occur due to extreme weather events outside of standard design guidance).

- 12 • [Pole/Tower Replacement and Reinforcements](#) – Transmission Pole/Tower
13 Replacement Program addresses remediation, adjustments, or installations
14 of new equipment to improve or replace existing transmission wood poles
15 and towers.
- 16 • [Traditional Overhead Hardening](#) – Traditional overhead hardening of
17 transmission conductor can occur through asset replacement and
18 maintenance programs. These activities include Dispersed Conductor
19 (Splice) Hardening and Conductor Segment Replacements
- 20 • [Asset Inspections](#) – PG&E performs detailed visual inspections via aerial
21 method (drone, helicopter, or aerial lift) paired with desktop image review or
22 by an inspector on the ground. These routine inspections seek to visually
23 identify asset conditions that could lead to an ignition.
- 24 • [Vegetation Management](#) – PG&E’s Transmission Routine Patrol Program
25 spans all transmission lines across PG&E’s service territory and consists of
26 several different methods for inspecting vegetation in proximity to
27 transmission facilities. The program scope is organized into North American
28 Electric Reliability Corporation (NERC) and non-NERC inspections.

**PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:**

CHAPTER 3.7

MISSED OVERHEAD DISTRIBUTION PATROLS IN HFTD AREAS

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.7
MISSED OVERHEAD DISTRIBUTION PATROLS IN HFTD AREAS

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2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 3.7**
4 **MISSED OVERHEAD DISTRIBUTION PATROLS IN HFTD AREAS**

5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (3.7) Overview**

8 **1. Metric Definition**

9 Safety and Operational Metric (SOM) 3.7 – Missed Overhead (OH)
10 Distribution Patrols in High Fire Threat District (HFTD) is defined as:

11 *Total number of overhead electric distribution structures that fell below*
12 *the minimum patrol frequency requirements divided by the total number of*
13 *overhead electric distribution structures that required patrols, in HFTD area*
14 *in past calendar year. “Minimum patrol frequency” refers to the frequency of*
15 *patrols as specified in General Order (GO) 165. “Structures” refer to electric*
16 *assets such as transformers, switching protective devices, capacitors, lines,*
17 *poles, etc.*

18 **2. Introduction of Metric**

19 Patrols involve simple visual observations to identify obvious structural
20 problems and hazards affecting safety or reliability. Within HFTD,
21 nonconformances identified by patrols can involve conditions that represent
22 a wildfire ignition risk. Performing required patrols on time ensures that
23 nonconformances are identified in a timely manner so that they can be
24 prioritized for repair in accordance with the risk of the condition.

25 Prior to year 2014, General Order (GO) 165 required that patrols be
26 completed any time between January 1 and December 31 each year.

27 Starting in 2015 and through 2019, Pacific Gas and Electric Company
28 (PG&E or the Company) implemented the new GO 165 requirement to
29 complete patrols each year within a prescribed timeframe, based on the
30 date of the last patrol or inspection. PG&E’s interpretation and
31 implementation of this new language calculated the due date for each patrol
32 each year as follows:

- 1 • The due date for each map is based on the date the map was last
2 inspected or patrolled;
- 3 • Inspections or patrols may not exceed three additional months past the
4 previous inspection or patrol date (12+3 months maximum);
- 5 • Inspections or patrols may be performed before the due date;
- 6 • Inspections or patrols are performed by the end of the calendar year
7 (12/31/YY); and
- 8 • The start of an inspection or a patrol starts a new inspection or patrol
9 interval that must be completed within the prescribed timeframe.

10 For the years 2020 and 2021, PG&E shifted away from the “12+3” due
11 date for completing patrols, with the intent of wildfire risk reduction by
12 focusing on the High Fire Threat District areas and using new risk models to
13 inform the prioritization of patrols. PG&E completed patrols by static due
14 dates, August 31 for HFTD areas, and December 31 for Non-HFTD areas.

15 In 2022, PG&E completed OH patrols and inspections in compliance
16 with GO 165. As of 2024, PG&E continues to complete patrols and
17 inspections in compliance with GO 165 (12+3). No changes in 2024 [and](#)
18 [2025](#).

19 **3. Audit Results**

20 In the Audit Report, Metric 3.7 received a Metric Accuracy Finding of
21 “Significant.”¹ This finding was based on a conclusion that manual
22 calculation of asset inspection due dates across multiple program years and
23 strategies led to data errors.² [The finding for 2024-2025 was resolved in the](#)
24 [9/30/25 filing. We plan to correct 2022-2023 in the 9/30/26 filing, but we do](#)
25 [not plan to correct 2021.](#) In addition, we will move to digitized patrols
26 [collecting structure-level data by December 31, 2026.](#)

1 Audit Report, p. 8, Table 1-1.

2 Audit Report, p. 118-119.

1 **B. (3.7) Metric Performance**

2 **1. Historical Data (2015 – 2025)**

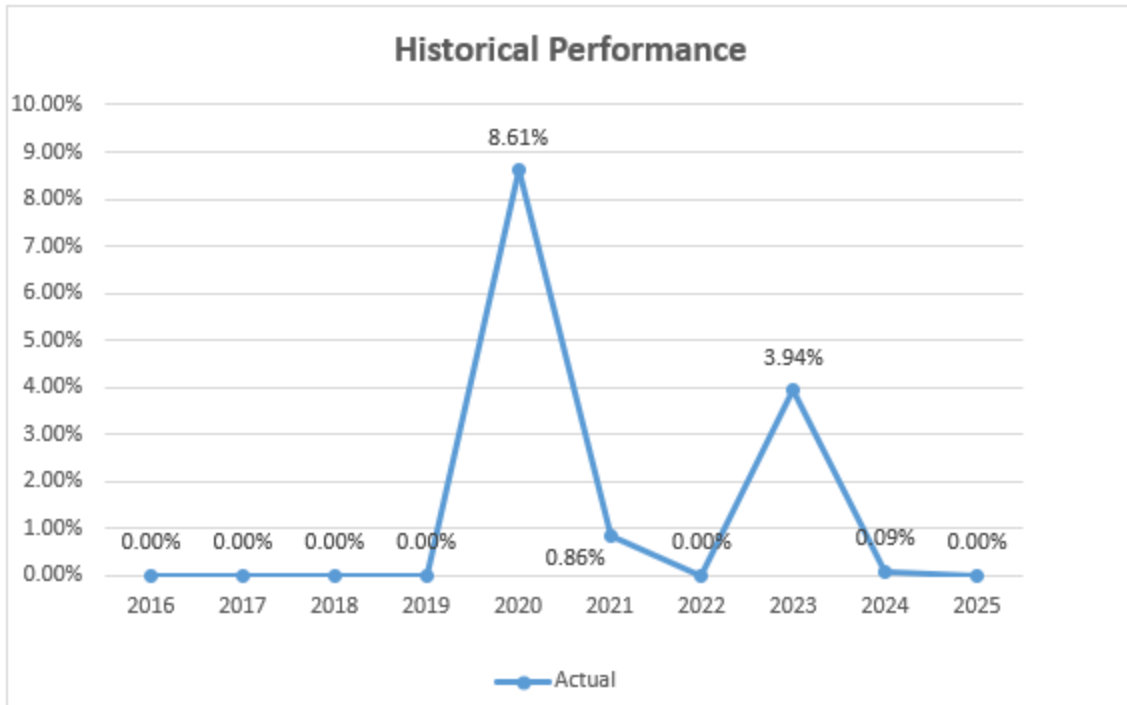
3 To be consistent with the implementation of new GO 165 requirements,
4 historical data begins in 2015.³ The 2015-2019 data include systemwide
5 results. The 2021-2025, data includes HFTD specific results.

6 Prior to 2020, PG&E completed patrols on paper by “plat map”. Each
7 plat map had a calculated “12+3” due date based on the start date of the last
8 patrol or inspection for that plat map. For the years 2015-2019, PG&E
9 tracked and measured performance of patrols based on the “12+3”
10 calculated due date for each *plat map*. Performance was tracked using
11 detailed excel spreadsheets for each of the 19 Divisions across the system,
12 and SAP data recorded for each plat map, which recorded the actual start
13 and end dates for each plat map, as well as actual units and the PG&E LAN
14 ID (login ID) of the Inspector who completed the work. PG&E’s annual
15 performance for completing patrols in these years was 0.00 percent
16 completed late.

17 For the years 2020 and 2021, PG&E’s performance was impacted by
18 the shift away from completing OH patrols by the “12+3” calculated due
19 dates to the use of a risk-based prioritization approach and focus on HFTD
20 with the intention of wildfire risk reduction.

³ Historical patrol data is at plat map level vs. structure level. We are further validating plat-based results for HFTD vs. NHFTD units, we may see slight changes to volumes completed late vs. on time, or vice-versa.

**FIGURE 3.7-1
HISTORICAL PERFORMANCE
(2015-2025)**



1 **2. Data Collection Methodology**

2 The currently used data collection methodology was implemented in
 3 2020. It uses a mobile platform for completing OH inspections, recorded at
 4 structure (pole) level using a detailed inspection checklist. PG&E also
 5 shifted its maintenance plan structure in SAP from purely plat -map based to
 6 circuit/risk based, tracking performance at *structure -level*.

7 PG&E continues to perform OH patrols on paper, with a goal of shifting
 8 to mobile technology similar to OH Inspections by 12/31/2026 OH Patrols
 9 are currently tracked at “maintenance plan” level, using excel spreadsheets
 10 and SAP data.

11 **3. Metric Performance for the Reporting Period**

12 Between 2015-2019, PG&E’s annual performance for completing patrols
 13 by the California Public Utilities Commission (CPUC) “12+3” due date was
 14 0 percent completed late. These results demonstrate our commitment to
 15 meet GO 165 CPUC “12+3” due dates.

16 For the years 2020 and 2021, with the shift to a wildfire risk reduction
 17 focused approach and away from completing OH patrols by the “12+3”

1 calculated due date, PG&E's metric performance was 8.61 percent
2 completed late in 2020, 0.86 percent completed late in 2021 and 0 percent
3 were completed late in 2022. For 2023, 3.94 percent were completed late.
4 For 2024, there were 543 late overhead patrols which equate to a
5 percentage of 0.09 percent completed late. There were three late overhead
6 patrols that was reported in the March 2025 report. However, the number of
7 late overhead patrols was corrected to 543. There were due date errors as
8 a result of calculation errors that resulted in a percent change from 0 to 0.09.
9 In 2025, there were 0 late overhead patrols which equates to 0 percent
10 completed late.

11 C. (3.7) 1-Year and 5-Year Target

12 1. Updates to 1- and 5-Year Targets Since Last Report

13 There have been no changes to the 1-year and 5-year targets since the
14 last SOMs filing.

15 2. Target Methodology

16 To establish the 1-year and 5-year targets, PG&E considered the
17 following factors:

- 18 • Historical Data and Trends: Based on historical performance of
19 0 percent completed late (2015-2019) and the results of the more
20 recently used wildfire risk reduction approach (2020-2023). In 2025
21 PG&E improved performance by completing OH patrols to (1) be in
22 compliance with GO 165, with a target range of 0-4 percent completed
23 late, and (2) incorporate Asset Strategy risk models.
- 24 • Benchmarking: Not available;
- 25 • Regulatory Requirements: GO 165;
- 26 • Attainable Within Known Resources/Work Plan: Targeted performance
27 is attainable within PG&E's currently known resource plan;
- 28 • Appropriate/Sustainable Indicators for Enhanced Oversight
29 Enforcement: The target range is a suitable indicator for Enhanced
30 Oversight and Enforcement as it intends to return PG&E to historical
31 levels of near-zero percent noncompliance while also incorporating
32 reasonable impacts resulting from access and other field issues; and
- 33 • Other Qualitative Considerations: None.

1 **3. 2026 Target**

2 The 2026 target is 0-4 percent to maintain performance compared to
3 2025.

4 **4. 2030 Target**

5 The 2030 (5-year target) is 0-1 percent to improve performance
6 compared to 2025, based on the factors described above, and the
7 commitment to continuously improve performance.

8 **D. (3.7) Performance Against Target**

9 **1. Progress Towards the 1-Year Target**

10 As demonstrated in Figure 3.7-2 below, PG&E continued to maintain
11 performance within the 0-4 percent target range set for 2025. For 2024,
12 there were 543 late overhead patrols which equate to a percentage of
13 0.09 percent completed late. The metric performance has shown
14 tremendous improvement from 3.94 percent in 2023. The spike in 2023 was
15 due to incorrect calculation of due dates for Distribution OH Patrols which
16 were identified and corrected. In 2025, there were 0 late overhead patrols
17 which equate to 0 percent completed late.

18 **2. Progress Towards the 5-Year Target**

19 As discussed in Section E below, PG&E has a number of programs to
20 improve the long-term performance of this metric and to meet the
21 Company's 5-year performance target.

**FIGURE 3.7-2
HISTORICAL PERFORMANCE
(2015 - 2025 AND TARGETS (2026-2030))**



E. (3.7) Current and Planned Work Activities

- Visibility and Compliance: Currently, Supervisors and Inspectors could see the CPUC due dates for each patrol package to ensure understanding as to the due date of the OH patrol.
- Tracking:
 - System Inspections track progress and completion of OH patrols on a continuous basis, using detailed excel tracking spreadsheets + SAP data;
 - System Inspections track and report-out on any “late” OH patrols, including identifying mitigating factors and implementing process improvements or changes to the program; and
 - System Inspections track timeliness of patrols being completed on their weekly scorecard.
- Training: System Inspections conduct refresher training to ensure understanding of the importance of patrols in identifying obvious structural problems and hazards in years where an inspection is not required.
- Maintenance Plan Management Tool: System Inspections Maintenance Planners complete timely review and completion of changes to structures and maintenance plans using the maintenance plan management tool.

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MISSED OVERHEAD DISTRIBUTION INSPECTIONS IN
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
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5 **HFTD AREAS**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.8) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metric (SOM) 3.8 – Missed Overhead
11 Distribution Detailed Inspections in HFTD Areas is defined as:

12 *Overhead Distribution Detailed Inspections in High Fire Threat District*
13 *(HFTD): Total number of structures that fell below the minimum inspection*
14 *frequency requirements divided by the total number of structures that*
15 *required inspection, in HFTD area in past calendar year. “Minimum*
16 *inspection frequency” refers to the frequency of scheduled inspections as*
17 *specified in General Order (GO) 165. “Structures” refers to electric assets*
18 *such as transformers, switching protective devices, capacitors, lines, poles,*
19 *etc.*

20 **2. Introduction of Metric**

21 Detailed inspections are performed to identify nonconformances
22 affecting safety or reliability. Within HFTD, nonconformances identified by
23 inspections can involve conditions that represent a wildfire ignition risk.
24 Performing required inspections on time ensures that non-conformances are
25 identified in a timely manner so that they can be prioritized for repair in
26 accordance with the risk of the condition.

27 Prior to year 2014, GO 165 required that inspections be completed any
28 time between January 1 and December 31 each year.

29 Starting in 2015 and through 2019, PG&E implemented the new GO 165
30 requirement to complete inspections each year within a prescribed
31 timeframe, based on the date of the last patrol or inspection. Pacific Gas
32 and Electric Company’s (PG&E or the Company) interpretation and

1 implementation of this new language calculated the due date for each patrol
2 or inspection each year as follows:

- 3 • The due date for each map is based on the date the map was last
4 inspected or patrolled;
- 5 • Inspections or patrols may not exceed three additional months past the
6 previous inspection or patrol date (12+3 maximum);
- 7 • Inspections or patrols may be performed before the due date;
- 8 • Inspections or patrols are performed by the end of the calendar year
9 (12/31/XX); and
- 10 • The start of an inspection or a patrol starts a new inspection or patrol
11 interval that must be completed within the prescribed timeframe.

12 For the years 2020 and 2021, PG&E shifted away from the “12+3” due
13 date for completing inspections with the intent of wildfire risk reduction by
14 focusing on the HFTD areas and using new risk models to inform the
15 prioritization of inspections each year. PG&E completed inspections by the
16 static due dates of, August 31 for HFTD areas, December 31 for Non-HFTD
17 areas.

18 In 2022, PG&E intends to complete overhead patrols and inspections in
19 compliance with GO 165.

20 In 2023 and beyond, PG&E will continue to complete patrols and
21 inspections in compliance with GO 165 (12+3). No changes in 2024 and
22 2025.

23 3. Audit Results

24 In the Audit Report, Metric 3.8 received a Metric Accuracy Finding of
25 “Significant.”¹ This finding was based on a conclusion that manual
26 calculation of asset inspection due dates across multiple program years and
27 strategies led to data errors.² [The finding for 2024-2025 was resolved in the
28 9/30/25 filing. We plan to correct 2022-2023 in the 9/30/26 filing, but we do
29 not plan to correct 2021.](#)

1 Audit Report, p. 8, Table 1-1.

2 Audit Report, p. 128.

1 **B. (3.8) Metric Performance**

2 **1. Historical Data (2015 – 2025)**

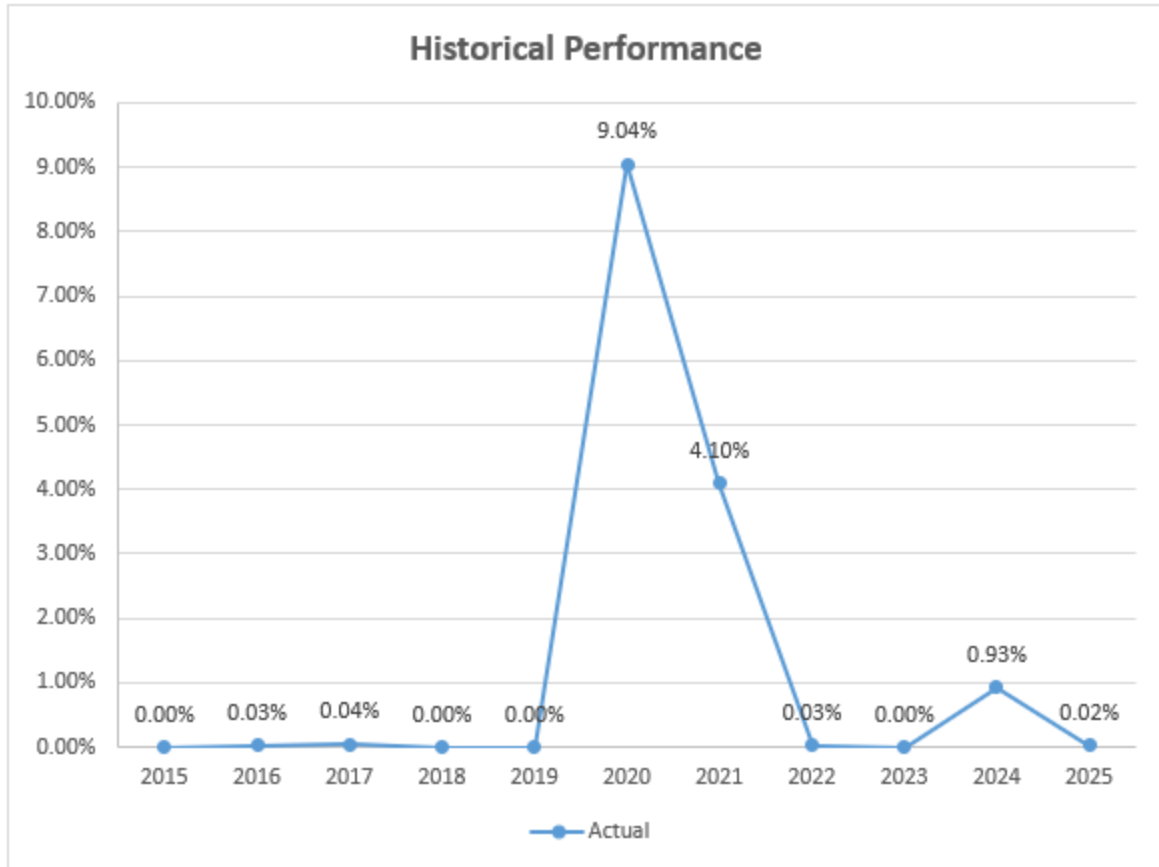
3 To be consistent with the implementation of new GO 165 requirements,
4 historical data begins in 2015. The 2015-2019 data include systemwide
5 results. The 2021-2025 data³ includes HFTD specific results.

6 Prior to 2020, Pacific Gas and Electric Company (PG&E) completed
7 inspections on paper by plat map. Each plat map had a calculated “12+3”
8 due date based on the start date of the last patrol or inspection for that plat
9 map. For the years 2015-2019, PG&E tracked and measured performance
10 of inspections based on the “12+3” calculated due date for each plat map.
11 Performance was tracked using detailed excel spreadsheets for each of the
12 19 Divisions across the system, and SAP data recorded for each plat map,
13 which recorded the actual start and end dates for each plat map, as well as
14 actual units and PG&E LAN ID (login ID) of the Inspector who completed the
15 work. PG&E’s annual performance for completion and inspections in these
16 years was 0.01-0.04 percent completed late.

17 For the years 2020 and 2021, PG&E’s performance was impacted by
18 the shift away from completing overhead inspection by the “12+3” calculated
19 due dates to the use of a risk-based prioritization approach and focus on
20 HFTD with the intention of wildfire risk reduction.

3 Historical inspection data <2020 is at plat map level vs. structure level. We are further validating plat map-based results for HFTD vs. NHFTD units, we may see slight changes to volumes completed late vs. on time, or vice-versa.

**FIGURE 3.8-1
HISTORICAL PERFORMANCE (2015– 2025)**



1 **2. Data Collection Methodology**

2 The currently used data collection methodology was implemented in
3 2020. It uses a mobile platform for completing Overhead inspections,
4 recorded at structure (pole) level using a detailed inspection checklist.
5 PG&E also shifted its maintenance plan structure in SAP from purely
6 plat-map based to circuit/risk based, tracking performance at
7 *structure -level.*

8 PG&E now tracks the completion of inspections at structure (pole) level,
9 using the “attainment report,” which records actual completion information
10 for each structure from actual inspection data recorded in SAP.

11 **3. Metric Performance for the Reporting Period**

12 Between 2015-2019, PG&E’s annual performance for completing
13 inspections by the CPUC “12+3” due date was 0 - 4 percent completed late.

1 These results demonstrate our commitment to meet GO 165 CPUC “12+3”
2 due dates.

3 For the years 2020 and 2021, with the shift to a wildfire risk reduction
4 focused approach and away from completing overhead inspections by the
5 “12+3” calculated due date, PG&E performance worsened to 9.04 percent
6 completed late in 2020 and 4.10 percent completed late in 2021. In 2022,
7 PG&E’s performance improved to 0.03 percent completed late. In 2023,
8 there were 10 late overhead inspections out of the 230,491 inspections
9 performed which equates to a percentage of 0 percent. In 2024, there were
10 94 late overhead inspections out of 10,058 inspections which equate to a
11 0.93 percent completed late. In 2025, there were 2 late overhead
12 inspections out of 9,085 inspections which equate to 0.02 percent completed
13 late.

14 C. (3.8) 1-Year and 5-Year Target

15 1. Updates to 1- and 5-Year Targets Since Last Report

16 There have been no changes to the 1-year and 5-year targets since the
17 last SOMS filing.

18 2. Target Methodology

19 To establish the 1-year and 5-year targets, PG&E considered the
20 following factors:

- 21 • Historical Data and Trends: Based on historical performance of
22 1-4 percent completed late (2015-2019) and the results of the more
23 recently used wildfire risk reduction approach (2020-2023). In 2024 and
24 continuing in 2025, PG&E improved performance by completing
25 overhead inspections: (1) be in compliance with GO 165, with a target
26 range of 0-2 percent completed late, and (2) incorporate Asset Strategy
27 risk models;
- 28 • Benchmarking: Not available;
- 29 • Regulatory Requirements: GO 165;
- 30 • Attainable Within Known Resources/Work Plan: Targeted performance
31 is attainable within PG&E’s currently known resource plan;
- 32 • Appropriate/Sustainable Indicators for Enhanced Oversight
33 Enforcement: The target range is a suitable indicator for Enhanced

1 Oversight and Enforcement as it intends to return PG&E to historical
2 levels of near-zero percent non-compliances while also incorporating
3 reasonable impacts resulting from access and other field issues; and
4 • Other Qualitative Considerations: None.

5 **3. 2026 Target**

6 The 2026 target is 0-2 percent to maintain performance compared to
7 2025.

8 **4. 2030 Target**

9 The 2030 (5-year target) is 0-1 percent to improve performance
10 compared to 2025, based on the factors described above, and the
11 commitment to continuously improved performance.

12 **D. (3.8) Performance Against Target**

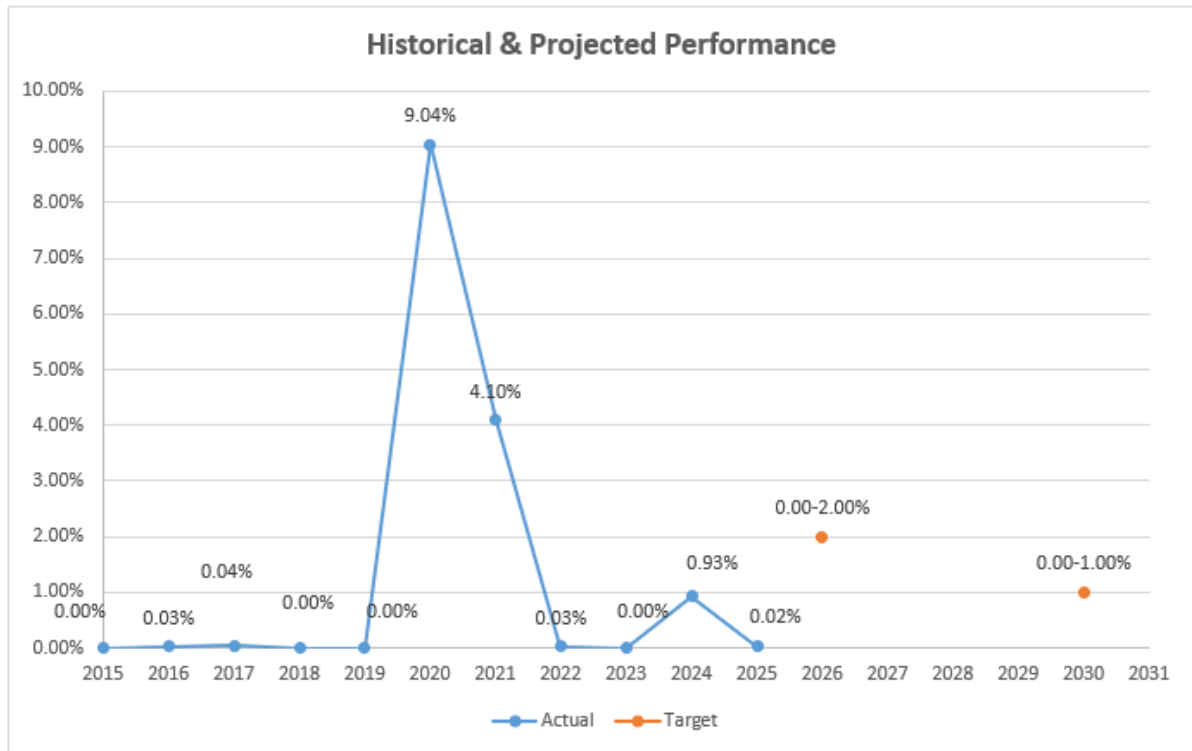
13 **1. Progress Towards/Deviation From the 1-Year Target**

14 As demonstrated in Figure 3.8-2 below, PG&E observed a 0.93 percent
15 missed overhead Distribution inspections in 2024 which was within the
16 Company's 1-year target. In 2025, there were 2 late overhead inspections
17 which equate to 0.02 percent completed late.

18 **2. Progress Towards/Deviation From the 5-Year Target**

19 As discussed in Section E below, PG&E has several programs to
20 maintain or improve long-term performance of this metric to meet the
21 Company's 5-year performance target.

**FIGURE 3.8-2
HISTORICAL PERFORMANCE (2015 - 2025) AND
TARGETS (2026 AND 2030)**



E. (3.8) Current and Planned Work Activities

- Visibility and Compliance: Currently Supervisors and Inspectors can see the CPUC due dates for each inspection, so that they can plan work to be completed on time.
- Tracking:
 - System Inspections tracked progress and completion of overhead inspections on a continuous basis, using detailed SAP data reports and excel tracking spreadsheets.
 - System Inspections tracked and reported-out on any overdue overhead inspections, including identifying mitigating factors and implementing process improvements or changes to address gaps.
 - System Inspections tracked timeliness of inspections being completed on their weekly scorecard.
- Training: System Inspections will conduct annual “Refresher” training on overhead inspections, which includes focus on anything that has changed since the previous year (guidance, standards, procedures), including

- 1 updates to the INSPECT application, inspection checklists, and associated
2 Inspector job aids.
- 3 • Asset Strategy – Monthly Inspection Validations: Monthly inspection
4 validations will continue to identify required additions to the original plan
5 arising from additions or changes to the asset registry.
 - 6 • Asset Strategy – Ad Hoc Inspections: Asset Strategy will continue to
7 evaluate the asset registry and may identify additional “ad hoc” structures to
8 be inspected each year, based on analysis related to ignition risk, etc.
 - 9 • Maintenance Plan Management Tool: System Inspections Maintenance
10 Planners will complete timely review and completion of changes to
11 structures and maintenance plans by way of the “maintenance plan
12 management tool.”
 - 13 • Desktop Quality Control: System Inspections conducts desktop work
14 verification activities on a valid sample size of completed inspections to
15 evaluate the completeness and quality of inspections.
 - 16 • Quality Control Field Work Verification: System Inspections conducts “blind”
17 field work verification activities on a valid sample size of completed
18 inspections to evaluate the completeness and quality of inspections.

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MISSED OVERHEAD TRANSMISSION PATROLS IN
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5 **HFTD AREAS**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.9) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metrics 3.9 – Missed Overhead (OH)
11 Transmission Patrols in High Fire Threat District (HFTD) Areas is defined as:

12 *OH Transmission Patrols in HFTD: Total number of structures that fell*
13 *below the minimum patrol frequency requirements divided by the total*
14 *number of structures that required patrols, in HFTD area in past calendar*
15 *year where, “Minimum patrol frequency” refers to the frequency of patrols*
16 *requirements, as applicable. “Structures” refers to electric assets such as*
17 *transformers, switching protective devices, capacitors, lines, poles, etc.*

18 **2. Introduction of Metric**

19 Patrols involve simple visual observations to identify obvious
20 non-conformances affecting safety or reliability. Within HFTD areas,
21 nonconformances identified by patrols can involve conditions that represent
22 a wildfire ignition risk. Performing patrols on time allows non-conformances
23 to be identified in a timely manner so that they can be prioritized for repair in
24 accordance with the risk of the condition.

25 All assets require either a detailed inspection or a patrol each year.
26 While detailed inspections have shifted from circuit-based cycles to an
27 inspection frequency that depends on HFTD and structure-level risk
28 considerations, patrols are performed by circuit. Therefore, any line that
29 does not receive a detailed inspection from end-to-end will require a patrol
30 and it is possible for some structures to receive both an inspection and a
31 patrol in the same year. Patrols may be performed either by air (helicopter)
32 or ground (walking or driving). Compared to transmission detailed

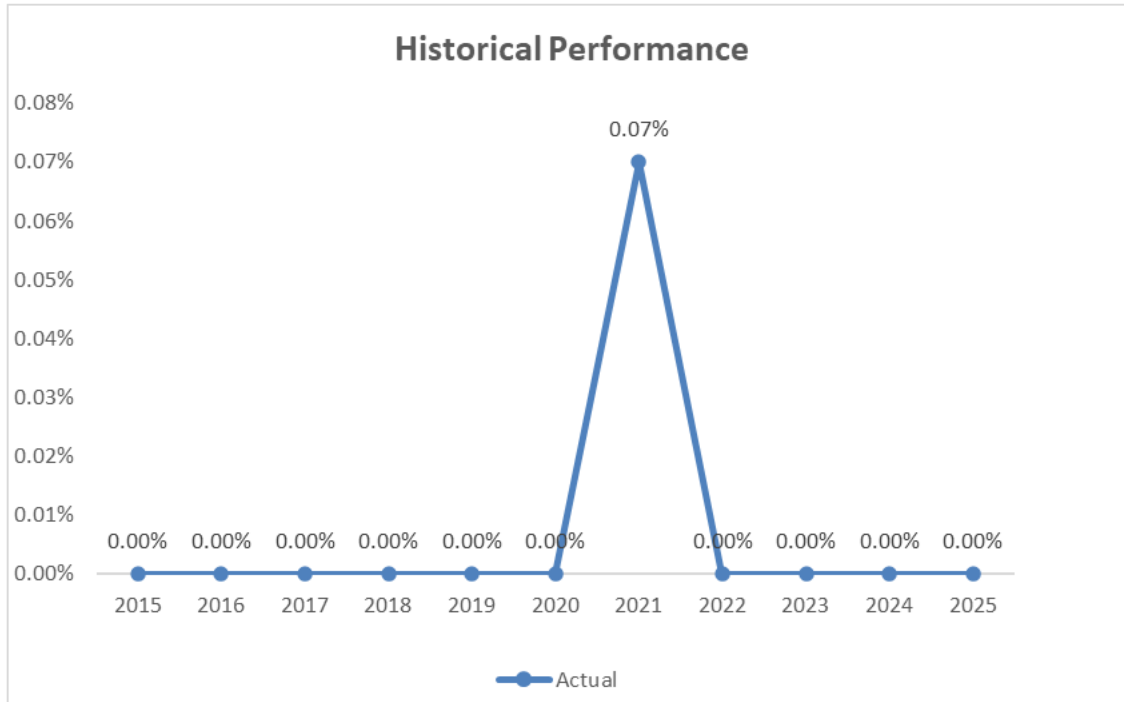
1 inspections, the transmission OH patrol program has not undergone
2 significant changes over the reporting period from 2015-present. Starting in
3 2021, Pacific Gas and Electric Company (PG&E) imposed an in-year
4 deadline of July 31 for patrols on circuits containing HFTD or High Fire Risk
5 Area structures. Monthly validations of the inspection plan were started in
6 June 2021, moving to quarterly in 2026, to ensure that all assets were either
7 inspected or patrolled each year, including assets that were newly added to
8 the asset registry. The in-year deadline of July 31 introduced in 2021 for
9 inspections and patrols in HFTD will continue to be used in 2022. Beginning
10 in 2022, assets added to the registry after July 31 or whose HFTD changes
11 after July 31 will not be considered late as in 2021, provided that they are
12 inspected or patrolled within 90 days of the addition to the registry or the
13 HFTD change.

14 **B. (3.9) Metric Performance**

15 **1. Historical Data (2015 – 2025)**

16 Historical data is provided from 2015 – 2025. Data provided for
17 2015-2019 reflects systemwide performance. HFTD-specific performance is
18 not available prior to 2020. The percentage of missed patrols is calculated
19 as the number of patrols not performed by the required deadline divided by
20 the total number of patrols performed for that year. Through 2020, there
21 was not a specific in-year deadline for patrols, so the deadline was
22 considered December 31. The July 31 deadline for HFTD patrols in 2021
23 allowed exceptions due to access issues and weather that may have
24 prevented a helicopter to fly, or where access issues may have prevented a
25 ground patrol. In 2021, HFTD structures added to the asset registry after
26 July 31 and inspected after the July 31 deadline were counted as missed
27 inspections, as well as instances where the asset location was corrected
28 from non-HFTD to HFTD after July 31.

**FIGURE 3.9-1
HISTORICAL PERFORMANCE
(2015-2025)**



1 **2. Data Collection Methodology**

2 Overhead patrols are tracked at the “maintenance plan” level, using data
3 sheets to record completion and findings, if applicable, as well as the SAP
4 data.

5 **3. Metric Performance for the Reporting Period**

6 In 2025 there are no missed patrols resulting in a 0.00 percent missed
7 overhead Transmission patrols with a total of 44,962 patrols completed—
8 25,283 in Tier 2 HFTD areas, 19,679 in Tier 3 HFTD areas.

9 **C. (3.9) 1-Year Target and 5-Year Target**

10 **1. Updates to 1- and 5-Year Targets Since Last Report**

11 There have been no changes to the 1-year and 5-year targets since the
12 last SOMs filing.

13 **2. Target Methodology**

14 To establish the 1-Year and 5-Year targets, PG&E considered the
15 following factors:

- 1 • Historical Data and Trends: The July 31 deadline for HFTD patrols was
2 first applied in 2021 and is still in practice. Therefore, targets use 2021
3 performance as a baseline with incremental improvement for the
4 reasons described below;
- 5 • Benchmarking: Not available;
- 6 • Regulatory Requirements: Relevant items include: (1) General
7 Order 165 requirements to follow internal maintenance procedures, and
8 (2) Wildfire Mitigation Plan targets to perform HFTD inspections and
9 patrols by July 31;
- 10 • Attainable Within known Resources/Work Plan: Targets are attainable
11 within currently known resources;
- 12 • Appropriate/Sustainable Indicators for Enhanced Oversight and
13 Enforcement: Targets are suitable indicators for Enhanced Oversight
14 and Enforcement as historical driver of worsening performance (asset
15 registry changes after July 31) will have an allowance to be counted as
16 on time if inspected within 90 days of the addition to the registry or
17 HFTD change at the beginning of 2022. This update ensures that the
18 metric is an appropriate indicator of performance by focusing the
19 measure on timely action to complete inspections as opposed to asset
20 registry completeness; and
- 21 • Other Qualitative Considerations: None.

22 3. 2026 Target

23 The 2026 target is to maintain performance to 0.00-0.02 percent, based
24 on the 90-day allowance for asset registry changes and consideration of
25 double circuits described in the methodology above. The target was
26 lowered for 2026 due to improved performance of missed patrols continue to
27 be low to none due to validation efforts started in 2021.

28 4. 2030 Target

29 The 2030 target is to maintain performance to 0.00-0.01 percent, based
30 on the 90-day allowance for asset registry changes and consideration of
31 double circuits described in the methodology above, as well as a reduction
32 over time in the number of asset registry additions from assets being
33 discovered in the field. The target was lowered for 2030 due to expected

1 improved performance of missed patrols from improved validation and asset
2 mapping processes.

3 **D. (3.9) Performance Against Target**

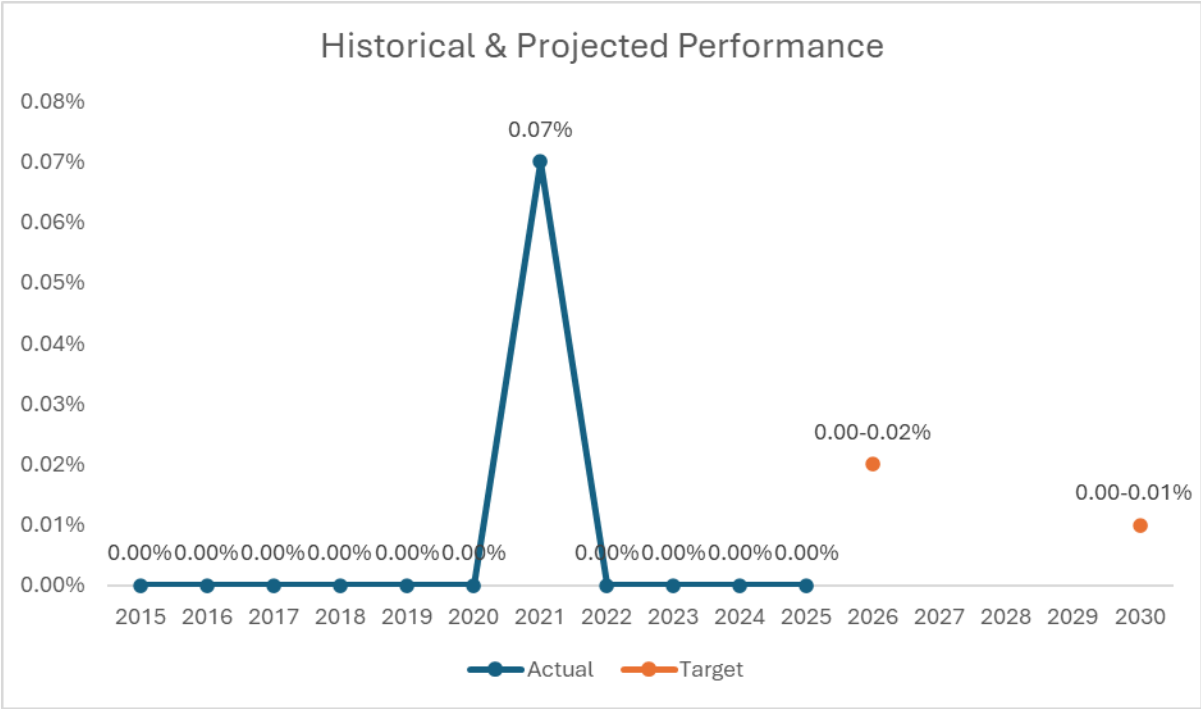
4 **1. Maintaining Performance Against the 1-Year Target**

5 As demonstrated in Figure 3.9-2 below, PG&E observed a 0.00 percent
6 missed overhead Transmission patrols in 2025 which is consistent with
7 PG&E's 1-year target.

8 **2. Maintaining Performance Against the 5-Year Target**

9 As discussed in Section E below, PG&E is deploying a number of
10 programs to maintain or improve long-term performance of this metric to
11 meet PG&E's 5-year performance target.

**FIGURE 3.9-2
HISTORICAL PERFORMANCE (2015-2025) AND
TARGET (2026 AND 2030)**



12 **E. (3.9) Current and Planned Work Activities**

13 Below is a summary description of the key activities that are tied to
14 performance:

- 1 • 2026 Inspection and Patrol Plan: The 2026 Inspection and Patrol plan has
2 been created, which defines the initial scope of the HFTD patrols that fall
3 under this metric. The plan contains approximately 520 circuits running
4 through HFTD areas (containing approximately 59,000 HFTD structures)
5 that will be patrolled.
- 6 • Quarterly Inspection Validations: Quarterly inspection validations, which
7 also consider required patrols, will continue to identify required additions to
8 the original plan arising from additions or changes to the asset registry.
9 Changes in HFTD affect the scope of patrols covered by this metric.
- 10 • In-Year Deadline Requirements: The in-year deadline of July 31 introduced
11 in 2021 for patrols in HFTD will continue to be used in 2026, with the same
12 provisions for access issues as in 2021 and the addition of the 90-day
13 requirement described above for additions and changes to the asset
14 registry. The deadline is tracked with the patrol orders so that each HFTD
15 patrol is identified as having the July 31 compliance requirement.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.10
MISSED OVERHEAD TRANSMISSION DETAILED INSPECTIONS

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 3.10**
4 **MISSED OVERHEAD TRANSMISSION DETAILED INSPECTIONS**

5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (3.10) Overview**

8 **1. Metric Definition**

9 Safety and Operational Metric (SOM) 3.10 – Missed Overhead
10 Transmission Detailed Inspections in HFTD Areas is defined as:

11 *Overhead (OH) Transmission Detailed Inspections in High Fire Threat*
12 *District (HFTD): Total number of structures that fell below the minimum*
13 *inspection frequency requirements divided by the total number of structures*
14 *that required inspection, in HFTD area in past calendar year where,*
15 *“Minimum inspection frequency” refers to the frequency of scheduled*
16 *inspections requirements, as applicable. “Structures” refers to electric*
17 *assets such as transformers, switching protective devices, capacitors, lines,*
18 *poles, etc.*

19 **2. Introduction of Metric**

20 Detailed inspections are performed using several methods (ground,
21 aerial, and climbing) to identify non-conformances affecting safety or
22 reliability. Within HFTD areas, non-conformances identified by inspections
23 can involve conditions that represent a wildfire ignition risk. Performing
24 inspections on time allows non-conformances to be identified in a timely
25 manner so that they can be prioritized for repair in accordance with the risk
26 of the condition.

27 Due to the importance of detailed inspections in identifying conditions
28 that affect wildfire, other safety, and reliability risks, the OH transmission
29 detailed inspection program has undergone significant evolution over the
30 reporting period for the metric, 2015-present. Prior to 2019, detailed ground
31 inspections were performed by circuit with a frequency depending on the
32 voltage and whether the majority of the structures on the circuit were wood
33 (2-year cycle) or steel (5-year cycle).

1 The Wildfire Safety Inspection Program (WSIP), which began in late
2 2018 and extended into 2019, introduced several key improvements to OH
3 transmission inspections including the use of an 'enhanced' inspection
4 methodology with a questionnaire developed from a wildfire-ignition Failure
5 Modes and Effects Analysis and the addition of aerial inspections using
6 high-resolution drone photographs to provide a second vantage point from
7 above to complement the ground inspections performed with the inspector
8 standing at the base of the structure. These improvements from WSIP were
9 incorporated into the regular OH inspection program beginning in 2020.

10 The 2020 inspections replaced the old wood- or steel-based inspection
11 cycles with cycles that called for more frequent inspections in HFTD areas,
12 annually for Tier 3 and on a 3-year cycle for Tier 2, compared to a 5-year
13 cycle for non-HFTD areas. The 2020 inspections also included non-HFTD
14 structures in High Fire Risk Areas (HFRA), which were treated like Tier 2.

15 The 2021 inspection program continued using the HFTD-based cycles
16 introduced in 2020 and imposed an in-year deadline for HFTD and HFRA
17 inspections of July 31, consistent with Pacific Gas and Electric Company's
18 (PG&E or the Company) 2021 Wildfire Mitigation Plan (WMP). The intent of
19 this deadline was to allow completion of the inspections, and any emergency
20 repairs found from the inspections prior to peak fire season. Monthly
21 validations of the inspection plan were started in June 2021, moving to
22 quarterly in 2026, to ensure that all assets requiring an inspection under
23 their prescribed cycles were included in the plan, including assets that were
24 newly added to the asset registry.

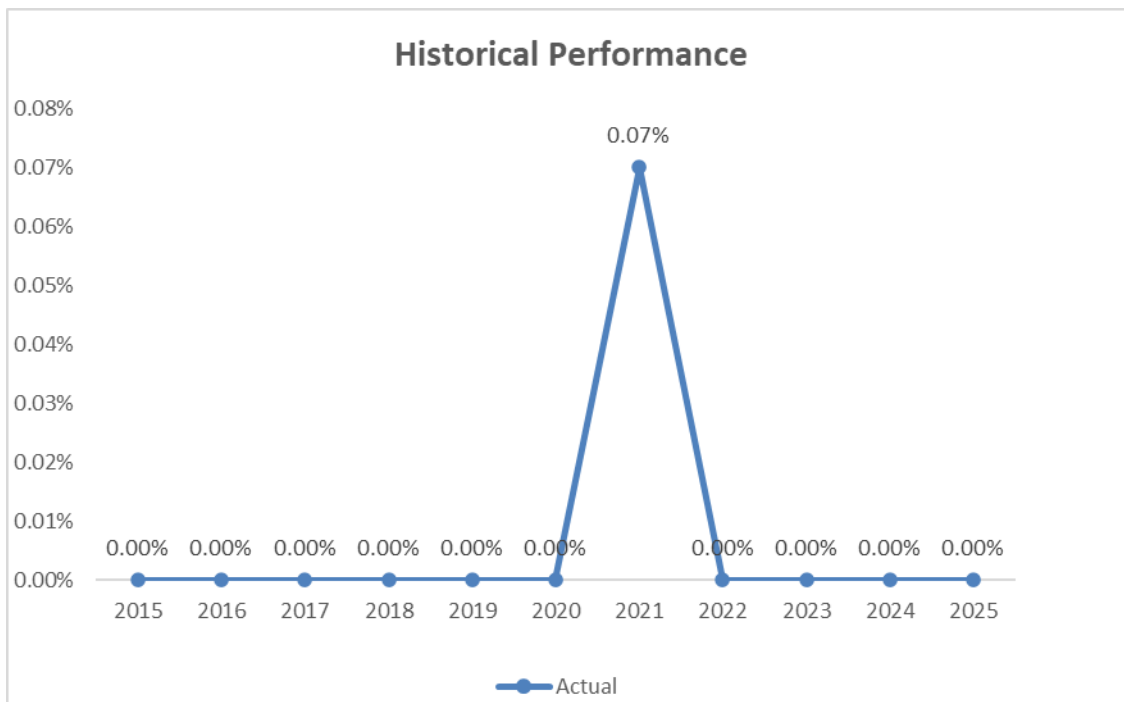
25 The 2022 inspection scope introduced the use of wildfire risk and
26 consequence scores at the structure level to inform the selection of assets
27 to be inspected. Inspection method and frequency is determined by wildfire
28 risk and structure type. At the beginning of 2022, assets were added to the
29 registry after July 31 or whose HFTD changes after July 31 will not be
30 considered late, provided that they are inspected within 90 days of the
31 addition to the registry or the HFTD change.

1 **B. (3.10) Metric Performance**

2 **1. Historical Data (2015 – 2025)**

3 [Historical data is provided from 2015-2025.](#) Data provided for
4 2015-2019 reflects systemwide performance. HFTD-specific performance is
5 not available prior to 2020. The percentage of missed inspections is
6 calculated as the number of inspections not performed by the required
7 deadline divided by the total number of inspections performed for that year.
8 Through 2020, there was not a specific in-year deadline for inspections, so
9 the deadline was considered December 31. The July 31 deadline for HFTD
10 inspections in 2021 allowed exceptions due to access issues, landowner
11 refusal, or site-specific worker safety situations (i.e., Cannot Get In (CGI))
12 where an unsuccessful inspection attempt was made prior to the deadline.
13 In 2021, HFTD structures added to the asset registry after July 31 and
14 inspected after the July 31 deadline were counted as missed inspections, as
15 well as instances where the asset location was corrected from non-HFTD to
16 HFTD after July 31.

**FIGURE 3.10-1
HISTORICAL PERFORMANCE PERCENT LATE
(2015-2025)**



1 **2. Data Collection Methodology**

2 The currently used data collection methodology was implemented in
3 2020. It uses a mobile platform for completing overhead inspections,
4 recorded at structure (pole) level using a detailed inspection checklist.

5 **3. Metric Performance for the Reporting Period**

6 In 2025, there was one missed inspection resulting in a 0.00 percent
7 (rounded) missed overhead Transmission detailed inspections with a total of
8 37,831 inspections completed—30,343 in Tier 2 HFTD area 7,488 in Tier 3
9 HFTD areas.

10 **C. (3.10) 1-Year Target and 5-Year Target**

11 **1. Updates to 1- and 5-Year Targets Since Last Report**

12 There have been no changes to the 1-year and 5-year targets since the
13 last SOMS filing.

14 **2. Target Methodology**

15 To establish the 1-Year and 5-Year targets, PG&E considered the
16 following factors:

- 17 • Historical Data and Trends: The July 31 deadline for HFTD inspections
18 was first applied in 2021 and is still in practice. Therefore, targets use
19 2021 performance as a baseline with incremental improvement for the
20 reasons described below;
- 21 • Benchmarking: Not available;
- 22 • Regulatory Requirements: Relevant items include: (1) General
23 Order 165 requirements to follow internal maintenance procedures, and
24 (2) WMP targets to perform certain HFTD inspections and patrols by
25 July 31;
- 26 • Attainable Within Known Resources/Work Plan: Targets are attainable
27 within currently known resources;
- 28 • Appropriate/Sustainable Indicators for Enhanced Oversight and
29 Enforcement: Targets are suitable indicators for Enhanced Oversight
30 and Enforcement as historical driver of worsening performance (asset
31 registry changes after July 31) will have an allowance to be counted as
32 on time for any assets discovered after January 1 of the given year and
33 due for a baseline frequency inspection based on installation date (via

1 the created date in SAP), will be inspected within 90 days of when
2 added to the asset registry or by July 31 or the given year, whichever is
3 later. Structures in scope for the given year with HFTD tier changes from
4 Non-HFTD to HFTD after January 1st are also given an allowance for
5 inspection within 90 days of the change or July 31, whichever is later.
6 This update beginning in 2022 ensures that the metric is an appropriate
7 indicator of performance by focusing the measure on timely action to
8 complete inspections as opposed to asset registry completeness.

- 9 • Other Qualitative Considerations: None.

10 3. 2026 Target

11 The 2026 target is to maintain performance to 0.00-0.02 percent, based
12 on the 90-day allowance for asset registry changes described in the
13 methodology above. The target was lowered for 2026 due to improved
14 performance of missed inspections continue to be low due to validation
15 efforts started in 2021.

16 4. 2030 Target

17 The 2030 target is to maintain performance to 0.00-0.01 percent, based
18 on the 90-day allowance for asset registry changes described in the
19 methodology above, as well as a reduction over time in the number of asset
20 registry additions from assets being discovered in the field. The target was
21 lowered for 2030 due to expected improved performance of missed
22 inspections from improved validation and asset mapping processes.

23 D. (3.10) Performance Against Target

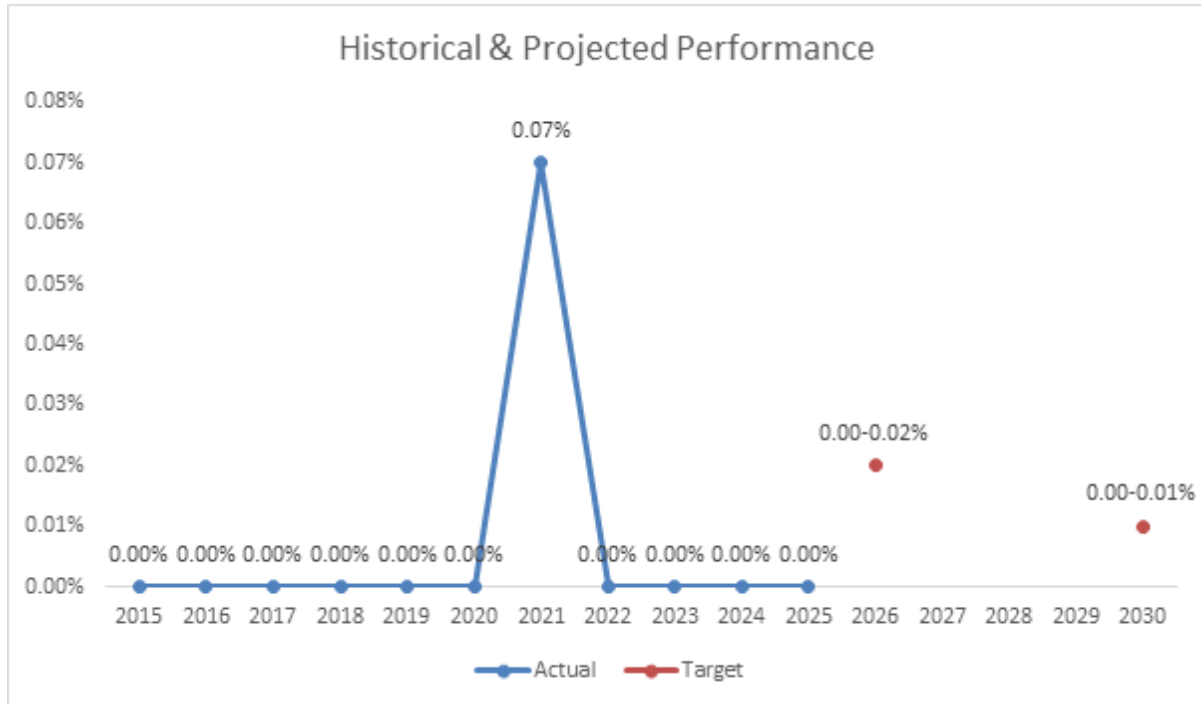
24 1. Progress Towards the 1-Year Target

25 As demonstrated in Figure 3.10-2 below, PG&E observed a
26 0.00 percent (rounded) missed overhead Transmission detailed inspections
27 in 2025 which is consistent with Company's 1-year target.

28 2. Progress Towards the 5-Year Target

29 As discussed in Section E below, PG&E has deployed a number of
30 programs to maintain or improve long-term performance of this metric to
31 meet the Company's 5-year performance target.

**FIGURE 3.10-2
HISTORICAL PERFORMANCE (2015-2025)
AND TARGETS (2026 AND 2030)**



E. (3.10) Current and Planned Work Activities

Below is a summary description of the key activities that are tied to performance.

- 2026 Inspection and Patrol Plan: The 2026 inspection plan has been created and contains Tier 3 and Tier 2 structures totaling approximately 13,000 receiving ground inspection, 25,000 aerial inspections, and approximately 1,700 structures that also will receive a climbing inspection.
- Quarterly Inspection Validations: Quarterly inspection validations will continue to identify required additions to the original plan arising from additions or changes to the asset registry. Changes in HFTD may affect the scope of inspections covered by this metric.
- In-Year Deadline Requirements: The in-year deadline of July 31 introduced in 2021 for inspections in HFTD will continue to be used in 2026, with the same provisions for CGI access issues as in 2021 and the addition of the 90-day requirement described above for additions and changes to the asset registry. The deadline is tracked with the inspection and patrol orders so

1 that each HFTD inspection is identified as having the July 31 compliance
2 requirement.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.11
GO 95 CORRECTIVE ACTIONS IN HFTDS

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 3.11**
4 **GO 95 CORRECTIVE ACTIONS IN HFTDS**

5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (3.11) Overview**

8 **1. Metric Definition**

9 Safety and Operational Metric (SOM) 3.11 – General Order (GO) 95
10 Corrective Actions in High Fire Threat Districts (HFTD) is defined as:

11 *The number of Priority Level 2 notifications that were completed on time*
12 *divided by the total number of Priority Level 2 notifications that were due in*
13 *the calendar year in HFTDs. Consistent with General Order (GO) 95*
14 *Rule 18 provisions, the proposed metric should exclude notifications that*
15 *qualify for extensions under reasonable circumstances.¹*

16 GO 95, Rule 18, Priority Level 2 has four relevant timeframes for
17 corrective action, of which 2 are relevant for HFTD criteria used in SOMs:
18 (1) 6 months for potential violations that create a fire risk in Tier 3 of HFTD;
19 (2) 12 months for potential violations that create a fire risk in Tier 2 of
20 HFTD.²

21 This metric is also reported as Metric 29 in the annual Safety
22 Performance Metrics Report.

23 **2. Introduction to the Metric**

24 The GO 95 Corrective Actions in HFTD metric measures the number of
25 Priority Level 2 electric corrective (EC) and line corrective (LC) notifications
26 (tags) in HFTD that are completed in accordance with the GO 95 Rule 18
27 timelines. Priority notifications are tracked to completion against procedural

1 Correction times may be extended under reasonable circumstances, such as:
third-party refusal, customer issue, no access, permits required, system emergencies
(e.g., fires, severe weather conditions).

2 GO 95 Rule 18, B1ai-aiii.

1 timelines that are consistent with the underlying risk of the work. Vegetation
2 Management (VM) work generally follows wildfire risk priorities.

3 **3. Background**

4 This metric consists of two major activities: corrective notification repairs
5 and VM. The section below describes the work, including risk-informed
6 prioritization and associated activities. We also compare Pacific Gas and
7 Electric Company's (PG&E or the Company) priority classifications against
8 GO 95 Rule 18's classification and timelines for completion.

- 9 • Corrective Notifications: PG&E identifies compelling abnormal
10 conditions on overhead electric equipment through routine inspection
11 and patrol programs we well as through other means such as in the
12 course of performing work. Regular inspections of our overhead and
13 underground electric assets are designed to meet GO 165
14 requirements. When an inspector identifies an abnormal compelling
15 condition, the inspector may immediately correct the condition by
16 performing minor work or recording the uncorrected condition as a tag.
- 17 • Tags are prioritized based on the risk posed by the condition and
18 urgency of repairs. Distribution priority Level 2 notifications are
19 subdivided into three categories based on the field conditions and
20 associated risk: Priority "X", Priority "B" and Priority "E". Priority "X"
21 notifications are scheduled to be addressed within seven days. Priority
22 "B" notifications are scheduled to be addressed within 6 months. The
23 due date for Priority E is within 6 months for Tier 3 and 12 months for
24 Tier 2.
- 25 • These distribution tags are reviewed by a team of Inspection Review
26 Specialists (IRS). The IRS review proposed findings for consistency
27 with the latest guidelines and creates EC notifications as needed. This
28 additional review drives consistency in inspection results by having a
29 centralized team review all priority "B" and priority "E" field findings prior
30 to recording the finding as a tag. Priority "X" tags are not reviewed
31 because they are scheduled to be addressed within seven days.
- 32 • VM: We routinely inspect clearances between our overhead electric
33 assets and adjacent vegetation through a variety of methods, including
34 observations during recurring patrols and targeted program inspections.

1 These inspections are conducted by VM personnel and/or contractors
2 and are designed to identify if tree work is required to meet or, in some
3 cases, exceed GO 95 Rule 35 requirements and fire safety regulations
4 that require a minimum clearance of 4 feet year-round for high-voltage
5 power lines in the California Public Utilities Commission
6 (Commission)-designated HFTD areas. GO 95 Rule 35 also requires
7 the removal of dead, diseased, defective, and dying trees that could fall
8 into the lines.

9 When an inspector identifies a clearance condition or a potential
10 tree hazard, they record an abatement prescription (tree work) within
11 VM's data systems. This tree work is assigned to tree crews and
12 completed in alignment with the timeframes defined in VM standards
13 and procedures, unless there are constraints that require prior resolution
14 before inspection or tree work proceeds (e.g., customer access, city or
15 agency permits, environmental considerations). Unless constrained,
16 tree work completion timing is based on HFTD Tier from the date it was
17 inspected, which is either 180 days for Tier 3 or 365 days for Tier 2.
18 Tree crews document the completion of tree work within VM data
19 systems. VM tree work identified in this way does not follow the EC
20 notifications (EC for Distribution) and Line Corrective notifications (LC
21 for Transmission) priority assignments. Our VM timeline to complete
22 this tree work generally aligns with the risk presented by the vegetation
23 and the risk reduction objectives of the VM Program. It is important to
24 note that this data is classified into two categories: (1) Vegetation Dead
25 and Dying and (2) Vegetation Priority 2, where each record reflects work
26 completed on a tree.

- 27 • Priority Classifications and Timelines for Completion: We manage our
28 corrective actions in HFTDs with a risk-informed prioritization of our
29 work plans. Our strategy focuses on reducing wildfire risk associated
30 with open corrective notifications. To accomplish this, we address the
31 highest risk Level 2 corrective notifications first. After that, we manage
32 the inventory of Level 2 Priority "E" corrective notifications in a
33 risk-informed manner, where the highest risk Level 2 Priority "E"
34 corrective notifications, within the same clearance point, are targeted

1 first, while deploying safety controls to manage the lower risk Level 2
2 Priority “E” corrective notifications. This approach allows strategic and
3 targeted wildfire risk reductions, informed by customer impact and risk
4 spend efficiencies, to continue to be our primary focus.

5 We recognize that our electric Priority “X” and Priority “B”
6 notifications have internal timelines that are more aggressive than
7 GO 95 Rule 18 Priority Level 2. However, consistent with the safety and
8 operational metric definitions provided in Decision 21-11-009, we are
9 reporting our performance against the timelines set forth in GO 95
10 Rule 18. Furthermore, we are including all EC and LC notifications, as
11 well as all inspection-identified vegetation safety hazards that meet the
12 definition of GO 95 Rule 18 Level 2.

13 At the end of 2022, Priority “B” was eliminated for newly created
14 transmission (LC) notifications so that priority “E” LC notifications now
15 directly align to Rule 18 Level 2. Priority “E” notifications may have
16 timelines shorter than the maximum allowable Level 2 timelines, so
17 3-month notifications still can be created as priority “E.” The existing
18 population of “B” priority notifications was closed in 2023.

19 The following table summarizes the priority classifications we use to
20 comply with GO 95 Rule 18. Transmission’s priority levels have
21 changed to remove priority “B,” allow reduced durations under
22 priority “E,” and increase the duration for priority “F” to align with the
23 Level 3 duration in GO 95 Rule 18.

24

**TABLE 3.11-1
GO 95 RULE 18 RISK CATEGORIES AND TIMELINES**

Line No.	GO 95 Rule 18 Level	PG&E Priority	Description	GO 95 Rule 18 Timeline for Corrective Action	PG&E Internal Timeline for Corrective Action (Electric Notifications)	PG&E Internal Timeline for Corrective Action (Vegetation Tree Work)
1	Level 1	A (Electric) Priority 1 (Vegetation)	An immediate risk of high potential impact to safety or reliability	Take corrective action immediately, either by fully repairing or by temporarily repairing and reclassifying to a lower priority	Consistent with GO 95 Rule 18	Within 24 hrs. after identification
2	Level 2	X (Electric Dx)	High potential impact to safety or reliability but do not pose an immediate risk.	Time period for corrective action to be determined at the time of identification by a qualified Company representative, but not to exceed: <ol style="list-style-type: none"> 6 months for potential violations that create a fire risk located in Tier 3 of the HFTD. 12 months for potential violations that create a fire risk located in Tier 2 of the HFTD. 12 months for potential violations that compromise worker safety; and 36 months for all other Level 2 potential violations. 	Corrective action within 7 days from date condition identified for electric equipment	N/A
		B (Electric Dx) Priority 2 or Dead & Dying (Vegetation)	Any other risk of at least moderate potential impact to safety or reliability: Take corrective action within specified time period (either by fully repair or by temporarily repairing and reclassifying to Level 3 priority).	Same as above	Corrective action within 6 months from date condition identified for electric equipment	<ol style="list-style-type: none"> Within 20 business days from identification Priority 2 Tag.(excluding work that is constrained) Dead & Dying tree(excluding work that is constrained): <ol style="list-style-type: none"> 6 months within Tier 3 & Tier 2 of the HFTD; and 12 months outside Tier 3 & Tier 2 of the HFTD.

**TABLE 3.11-2
GO 95 RULE 18 RISK CATEGORIES AND TIMELINES
(CONTINUED)**

Line No.	GO 95 Rule 18	PG&E Priority	Description	GO 95 Rule 18 Timeline for Corrective Action	PG&E Internal Timeline for Corrective Action (Electric Notifications)	PG&E Internal Timeline for Corrective Action (Vegetation Tree Work)
3		E (Electric)	Any other risk of at least moderate potential impact to safety or reliability: Take corrective action within specified time period (either by fully repair or by temporarily repairing and reclassifying to Level 3 priority).	Same as above	Corrective action within: 6 months for conditions that create a fire risk located in HFTD Tier 3 12 months for conditions that create a fire risk located in HFTD Tier 2 12 months for potential violations that compromise worker safety; and 36 months for all other Level 2 potential violations. Transmission: Corrective action timelines can be reduced below the maximum values listed above.	N/A
4		H (Electric Dx)	These are PG&E Priority "E" Notifications that are planned to be addressed by a planned System Hardening Project	Same as above	Same as above-	N/A
5	Level 3	F (Electric)	Any risk of low potential impact to safety or reliability	Take corrective action within 60 months subject to the specific exceptions. ^(a)	Corrective actions to be addressed within five years from date condition is identified.	N/A

(a) EXCEPTION – Potential violations specified in Appendix J or subsequently approved through Commission processes, including, but not limited to, a Tier 2 Advice Letter under GO 96B, that can be completed at a future time as opportunity-based maintenance. Where an exception has been granted, repair of a potential violation must be completed the next time the Company's crew is at the structure to perform tasks at the same or higher work level (i.e., the public, communications, or electric level). The condition's record in the auditable maintenance program must indicate the relevant exception and the date of the corrective action.

1 **4. Audit Results**

2 In the Audit Report, Metric 3.11 received a Metric Accuracy Finding of
3 “Significant (2021 only).”³ This finding was due to erroneous calculations
4 from VM, Transmission, and Distribution.⁴ The findings are resolved.

5 The erroneous calculations for 2021 were corrected in the September
6 report. As part of the audit, PG&E also identified a population of EC
7 notifications with erroneous compliance due dates, investigated underlying
8 causes and established corrective actions. The corrective actions for
9 Distribution were tracked by Corrective Action Plan and completed on
10 December 15, 2025, prior to the due date of December 31, 2025.

11 **B. (3.11) Metric Performance**

12 **1. Historical Data (2020-2025)**

13 We are reporting historical data from the years 2020 through 2025. The
14 historic data for 2021 has been corrected as stated in Section A.4 above.

15 Our history of available data, which is recorded in our electric work
16 management systems (e.g., SAP) goes back to 2010. However, we are
17 focusing our historical reporting for this metric starting at 2020 due to
18 various changes that occurred prior to 2020, which reshaped GO 95 and
19 GO 165 to include boundaries for HFTD, as well as informed our current
20 inspection methods to be more enhanced towards identifying ignition risks.

21 Reported timelines generally align with VM adoption of updated internal
22 timeliness for Priority Tag mitigation and additional ‘Dead & Dying’ tree
23 abatement identified through the implementation of PG&E Enhanced
24 Vegetation Management (EVM) Program in 2019. The VM Program’s work
25 management systems track tree prescriptions and completion of
26 trim/removal through separate databases; the VM Database and OneVM.

27 **2. Data Collection Methodology**

28 Data collected prior to year 2020 is excluded due to the various GO 165
29 and GO 95 Rule 18 changes mentioned above.

3 Audit Report, p. 8, Table 1-1.

4 Audit Report, pp. 146-147.

1 We are including all EC (Distribution) and LC (Transmission)
2 notifications, as well as all inspection-identified vegetation safety hazards
3 that meet the definition of GO 95 Rule 18 Level 2. Note that due dates must
4 be manually adjusted in our data to align with the GO 95 Rule 18 timelines
5 which vary from our internal timelines as previously mentioned.

6 **3. Metric Performance for the Reporting Period**

7 Metric performance is comprised of an aggregated performance for
8 electric distribution and electric transmission (ET) corrective notifications, as
9 well as vegetation safety hazards.

10 As described in earlier sections, we are reporting and setting targets
11 against the timeframes identified in GO 95 Rule 18 rather than the timelines
12 articulated in our internal electric Priority “X”, Priority “B” and “E”
13 notifications, and internal VM Priority 2 and Dead and Dying Tree abatement
14 corrective notifications.

15 To address the unprecedented wildfire risk in our service territory, in
16 2019 we launched our Wildfire Safety Inspection Program (WSIP) as part of
17 our Wildfire Safety Plan. The intent of that program was to expand our
18 focus during inspections to include fire ignition risk posed by failure modes
19 on our electric assets and accelerate the inspections to be complete by the
20 beginning of the 2019 wildfire season. The WSIP generated a volume much
21 greater than what we have typically experienced for our annual EC
22 notification volume, with the majority of EC notifications being of lower risk
23 (e.g., Level 2 Priority “E” & Level 3).

24 Given the high volume (e.g., approximately 4x the volume from prior
25 years) of identified electric distribution and transmission corrective
26 notifications in the 2019 WSIP, we pivoted from managing our EC
27 notifications based on due date to focusing our priority through a wildfire risk
28 informed approach. This means we would complete Level 1 and Level 2
29 Priority “X” and Priority “B” corrective notifications based on their GO 95
30 Rule 18 deadlines and internal standards and manage the maintenance log
31 of Level 2 Priority “E” and Level 3 corrective notifications in a risk-prioritized
32 manner.

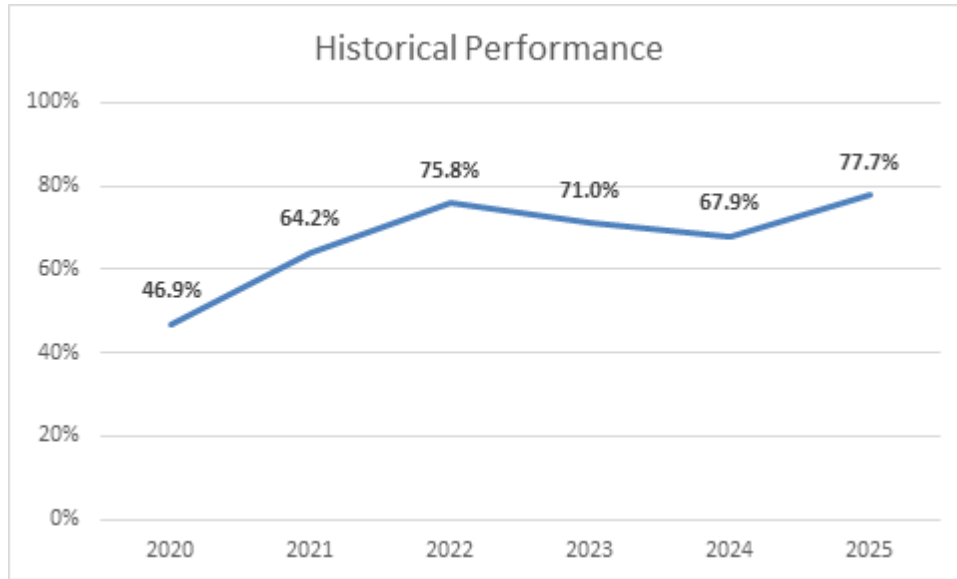
33 As described in the 2026-2028 WMP, we are continuing to work down
34 the distribution EC notification maintenance log based on risk prioritization,

1 and we have accelerated the work in the HFTD by bundling and working
2 notifications by isolation zone. Bundling by isolation zone provides us the
3 flexibility to address the most risk first through a [Cost Benefit Ratio \(CBR\)](#)
4 approach and is providing significant savings in execution efficiency.
5 Bundling also reduces the number of customer outages required and
6 improves customer satisfaction. Through bundling and other improvements,
7 our plan is to be in compliance with GO 95 in the HFTDs by the end of 2029.
8 While PG&E's maintenance tag plan will result in some lower-risk
9 maintenance tags exceeding the current GO 95, Rule 18 timelines, the plan
10 is prudent because it will allow PG&E to reduce the maintenance log more
11 quickly and execute more tags with the same amount of resources while
12 reducing the amount of clearances needed per unit executed.

13 We are also currently completing available vegetation priority corrective
14 notifications within our internal timelines, excluding corrective notifications
15 where we are constrained due to external factors, such as customer
16 interferences or permitting. Trees are worked as dependencies and
17 constraints are resolved. This is consistent with our Dead and Dying Tree
18 Abatements.

19 The following figure plots our historical performance for GO 95 Rule 18
20 Level 2 HFTD Corrective Notifications.

**FIGURE 3.11-1
GO 95 CORRECTIVE ACTIONS IN HFTDS – HISTORICAL PERFORMANCE (2020 – 2025)**



**TABLE 3.11-3
GO 95 RULE 18 PRIORITY LEVEL 2 ACTUAL 2025
CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION, ET AND VM)**

Line No.	Year 2025	Level 2 Results
1	On Time	179,736
2	Past Due	51,661
3	Percent On Time	77.7%

**TABLE 3.11-4
GO 95 RULE 18 LEVEL 2 ACTUAL 2025
CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION ONLY)**

Line No.	Year 2025	Level 2 Priority "E"	Level 2 Priority "B"	Level 2 Priority "B" From "E"	Level 2 Priority "X"	Level 2 Results
1	On Time	1,845	5,405	110	2,177	9,537
2	Past Due	50,134	249	49	0	50,432
3	Percent On Time	3.5%	95.6%	69.2%	100.0%	15.9%

**TABLE 3.11-5
GO 95 RULE 18 LEVEL 2 ACTUAL 2025
CORRECTIVE ACTIONS PERFORMANCE
(ET ONLY)**

Line No.	Year 2025	Level 2 Results
1	On Time	6,633
2	Past Due	793
3	Percent On Time	89.3%

Note: Per PG&E Utility Procedure TD-8123P-103, effective 1/03/2023, all Level 2 Transmission tags are considered priority "E" which aligns with GO 95, Rule 18 Levels 1, 2, and 3. Tag priority categorization will no longer be provided for Transmission tags.

**TABLE 3.11-6
GO 95 RULE 18 LEVEL 2 ACTUAL 2025
CORRECTIVE ACTIONS PERFORMANCE
(VM)**

Line No.	Year 2025	EVM Dead and Dying	Vegetation Dead and Dying	Vegetation Priority 2	Level 2 Results
1	On Time	813	92,481	70,272	163,566
2	Past Due	85	299	52	436
3	Percent On Time	90.5%	99.7%	99.9%	99.7%

1 **C. (3.11) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 The 1-year and 5-year targets have not changed since the last SOMs
4 filing.

5 **2. Target Methodology**

6 To establish the 1-Year and 5-Year targets, we considered the following
7 factors:

- 8 • Historical Data and Trends: The targets are based on the projected
9 volume of GO 95 Rule 18 Priority Level 2 notifications, which consider
10 existing open tags and forecasted new tags that are due for each year;
- 11 • Benchmarking: Not available;
- 12 • Regulatory Requirements: GO 95 Rule 18 requirements;

- 1 • Attainable Within Known Resources/Work Plan: Attainability is subject
2 to other emerging higher risk priorities that may influence our ability to
3 meet projected targets. If emerging higher risk priorities emerge
4 throughout the course of the year, we may need to prioritize our
5 available resources to address these higher risk priorities and adjust our
6 work plan accordingly;
- 7 • Appropriate/Sustainable Indicators for Enhanced Oversight and
8 Enforcement: Yes, performance at projected levels is sustainable,
9 subject to other emerging higher risk priorities may influence ability to
10 meet projected targets. If emerging higher risk priorities emerge
11 throughout the course of the year, we may need to prioritize our
12 available resources to address these higher risk priorities and adjust our
13 work plan accordingly; and
- 14 • Other Qualitative Considerations: This target was established with the
15 consideration of our risk-informed strategy, as opposed to a corrective
16 notification due date prioritization approach.

17 3. 2026 Target

18 Our target for Priority Level 2 corrective maintenance notifications on
19 time completion rates is 65.4 percent for the year 2026. This metric
20 performance is comprised of an aggregated score combining performance
21 of electric distribution, ET and VM.

22 Electric distribution notifications completed on time percentage is
23 projected at approximately 13 percent and ET notifications completed on
24 time percentage is projected at approximately 80 percent. The projected
25 forecast for VM is approximately 98 percent.

26 The 2026 target is lower than the 2025 target because the projected
27 volume of VM work is lower in 2026, and the Distribution metric target is also
28 lower. The lower volume of VM work is the primary driver of the lower
29 consolidated target because VM accounts for the majority of the
30 consolidated work (71 percent in 2026 and 60 percent in 2025) and it has
31 the highest on-time rate.

32 The 2026 distribution target is lower than previous years because we
33 are prioritizing highest risk tags and Risk Spend Efficiency instead of
34 completing tags that are due in-year. Our distribution corrective notifications

1 strategy will continue to focus on reducing wildfire risk associated with our
2 open corrective notifications by working the highest CBR bundles for Level 2
3 corrective notifications first versus managing corrective notification due
4 dates. Using this approach in 2023 through 2025, we reduced the relative
5 wildfire risk associated with backlog⁵ open electric distribution corrective
6 maintenance notifications in HFTD Tiers 2 and 3 by as much as
7 73.4 percent. After selecting 2026 work based on risk reduction, work
8 readiness data was analyzed to determine what the forecasted on-time rate
9 will be. While priority B and X tags are expected to have high on-time
10 completion rates based on historical data and planned operational support,
11 priority E tags represent the majority of the tags due and these are worked
12 according to the CBR priority of their bundle, not by their due date.

13 Transmission Line improved on-time performance on Level 2 HFTD
14 notifications within 2025 by eliminating conflicting priorities with the
15 remaining open WMP backlog and utilizing the GO 95 rule 18 extension
16 process for all reasonable circumstances. T-Line plans to maintain the 2025
17 on-time percentage and look for ways to continue improving our overall
18 on-time performance.

19 For VM, our forecast has been adjusted to account for the expected find
20 rate of trees requiring work, and to reflect the volume of trees that may be
21 constrained due to external factors. The focus of VM will continue to be
22 placed on execution of the wildfire mitigation programs described in the
23 2026-2028 WMP.

24 The following tables summarize PG&E's Year 2026 Target for Priority
25 Level 2 notifications completed on time percentage, as well as a breakdown
26 between the electric distribution, ET and VM Priority Level 2 notifications
27 performance.

⁵ Backlog tags are open ignition EC notifications known as of January 5, 2023, and found prior to Jan 1, 2023, in HFTD/HFRA locations.

**TABLE 3.11-7
GO 95 RULE 18 PRIORITY LEVEL 2 PROJECTED 2026
CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION, ET AND VM)**

Line No.	Year 2026	Level 2 Results
1	On Time	109,267
2	Past Due	57,689
3	Percent On Time	65.4%

**TABLE 3.11-8
GO 95 RULE 18 LEVEL 2 PROJECTED 2026
CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION ONLY)**

Line No.	Year 2026	Level 2 Priority "E"	Level 2 Priority "B"	Level 2 Priority "B" From "E"	Level 2 Results
1	On Time	7,044	1,009	116	8,169
2	Past Due	54,181	0	673	54,854
3	Percent On Time	11.5%	100.0%	14.7%	13.0%

**TABLE 3.11-9
GO 95 RULE 18 LEVEL 2 PROJECTED 2026
CORRECTIVE ACTIONS PERFORMANCE
(ET ONLY)**

Line No.	Year 2026	Level 2 Results
1	On Time	3360
2	Past Due	840
3	Percent On Time	80.0%

**TABLE 3.11-10
GO 95 RULE 18 LEVEL 2 PROJECTED 2026
CORRECTIVE ACTIONS PERFORMANCE
(VM)**

Line No.	Year 2026	HFTD Tier 2	HFTD Tier 3	Level 2 Results
1	On Time	58,097	41,635	97,738
2	Past Due	1,162	833	1,995
3	Percent On Time	98.0%	98.0%	98.0%

1 **4. 2030 Target**

2 Our 5-year target for Priority Level 2 corrective maintenance
3 notifications on time is 91.7 percent.

4 For year 2030, we are projecting an on-time percentage of
5 approximately 82 percent, 95 percent, and 98 percent for electric
6 distribution, ET, and vegetation notifications performance, respectively.

7 This increase in the distribution target aligns with our goal of being
8 steady-state in HFTDs by the end of 2029. Once we have worked down the
9 maintenance log of tags in HFTDs we will be able to prioritize tags by their
10 due date. In the meantime, our distribution corrective notifications strategy
11 will focus on reducing the most wildfire risk associated with our open
12 corrective notifications per dollar spent by working the highest risk bundles
13 by isolation zone first.

14 The following tables summarize our Year 2030 Target for Priority
15 Level 2 notifications completed on time percentages, as well as a
16 breakdown between the electric distribution, ET and vegetation Priority
17 Level 2 notifications completed on time percentages.

**TABLE 3.11-11
GO 95 RULE 18 PRIORITY LEVEL 2 PROJECTED 2030
CORRECTIVE ACTIONS PERFORMANCE
(ELECTRIC DISTRIBUTION, ET AND VM)**

Line No.	Year 2030	Level 2 Results
1	On Time	157,941
2	Past Due	14,380
3	Percent On Time	91.7%

**TABLE 3.11-12
GO 95 RULE 18 LEVEL 2 PROJECTED 2030 CORRECTIVE ACTIONS
PERFORMANCE
(ELECTRIC DISTRIBUTION ONLY)**

Line No.	Year 2030	Level 2 Priority "E"	Level 2 Priority "B"	Level 2 Priority "B" From "E"	Level 2 Results
1	On Time	46,747	8,241	962	55,951
2	Past Due	11,686	434	51	12,170
3	Percent On Time	80.0%	95.0%	95.0%	82.1%

**TABLE 3.11-13
GO 95 RULE 18 LEVEL 2 PROJECTED 2030 CORRECTIVE ACTIONS
PERFORMANCE
(ET ONLY)**

Line No.	Year 2030	Level 2 Results
1	On Time	3990
2	Past Due	210
3	Percent On Time	95.0%

**TABLE 3.11-14
GO 95 RULE 18 LEVEL 2 PROJECTED 2030 CORRECTIVE ACTIONS
PERFORMANCE
(VM)**

Line No.	Year 2030	Level 2 Results
1	On Time	98,000
2	Past Due	2,000
3	Percent On Time	98.0%

1 The Figure 3.11-2 plots our aggregated historical and aggregated
2 projected performance for GO 95 Rule 18 Level 2 HFTD Corrective
3 Notifications.

4 **D. (3.11) Performance Against Target**

5 **1. Progress Towards 1-Year Target**

6 PG&E achieved 77.7 percent on-time completions in 2025, exceeding
7 the target of 73.8 percent. Distribution's contribution to that consolidated
8 metric fell short of the 2025 target, but Transmission and VM exceeded their
9 2025 targets.

10 VM is completing Level 2 work 99.7 percent on time. This timeliness
11 performance is 0.1 percent less with the 99.8 percent YTD 2025, but
12 maintains the improvements from the 2024 timeliness performance of
13 99.1 percent. VM continues to focus on customer engagement, around the
14 risk-mitigation benefits of this work, to improve constraint resolution
15 outcomes.

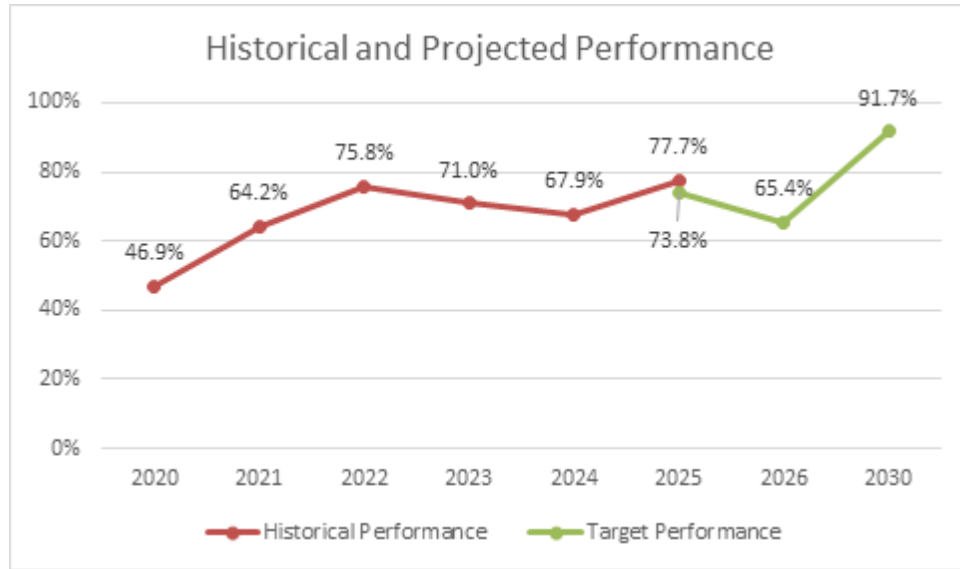
16 Transmission completed Level 2 work 89.3 percent on time in 2025.
17 This improvement is attributed to a reduction in competing priorities,
18 allowing the Transmission team to dedicate greater focus toward completing
19 HFTD notifications within the required timelines. Additionally, Transmission
20 has begun appropriately leveraging G.O. 95, Rule 18 extensions for
21 notifications that cannot be completed on time due to reasonable
22 circumstances.

23 Distribution completed Level 2 work 15.9 percent on time in 2025. B tag
24 on-time completions increased in 2025 and X tag were completed
25 100 percent on-time. E tag on-time completions were lower than forecasted
26 for 2025, however, and drove the performance lower than target.

27 **2. Progress Towards the 5-Year Target**

28 As discussed in Section E below, PG&E is deploying a number of
29 programs to maintain or improve long-term performance of this metric to
30 meet the Company's 5-year performance target.

FIGURE 3.11-2
GO 95 CORRECTIVE ACTIONS IN HFTDS – HISTORICAL AND TARGET



1 **E. (3.11) Current and Planned Work Activities**

2 Below is a summary description of the key activities that are tied to
3 performance and their description.

- 4 • Overhead Preventative Maintenance and Equipment Repair: Focuses on
5 repair of electric equipment identified with corrective notifications. Our
6 corrective notifications strategy is outlined in Section 3. Metric Performance
7 for the Reporting Period.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.12
ELECTRIC EMERGENCY RESPONSE TIME

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.12
ELECTRIC EMERGENCY RESPONSE TIME

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 3.12**
4 **ELECTRIC EMERGENCY RESPONSE TIME**

5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (3.12) Overview**

8 **1. Metric Definition**

9 Safety and Operational Metric 3.12 – Electric Emergency Response
10 Time is defined as:

11 *Average time and median time in minutes to respond on-site to an*
12 *electric related emergency notification from the time of notification to the*
13 *time a representative (or qualified first responder) arrived onsite.*

14 *Emergency notification includes all notifications originating from 911 calls*
15 *and calls made directly to the utilities’ safety hotline. The data used to*
16 *determine the average time and median time shall be provided in*
17 *increments as defined in General Order 112-F 123.2 (c) as supplemental*
18 *information, not as a metric.*

19 **2. Introduction of Metric**

20 This metric measures the average and median time for Pacific Gas and
21 Electric Company (PG&E) to respond on-site to an electric emergency once
22 a notification is received. Measuring response to calls into PG&E’s
23 Emergency line from first responder agencies within 60 minutes has been a
24 long-standing, priority public safety measure for PG&E and within the
25 industry, and this metric, although calculated differently, is similar in its intent
26 for responding quickly to our customers and any potentially unsafe
27 conditions reported.

28 **B. (3.12) Metric Performance**

29 **1. Historical Data (2015 – 2025)**

30 Historical data is provided from 2015 through 2025. Although
31 emergency response data exists prior to 2015 (as mentioned below), current

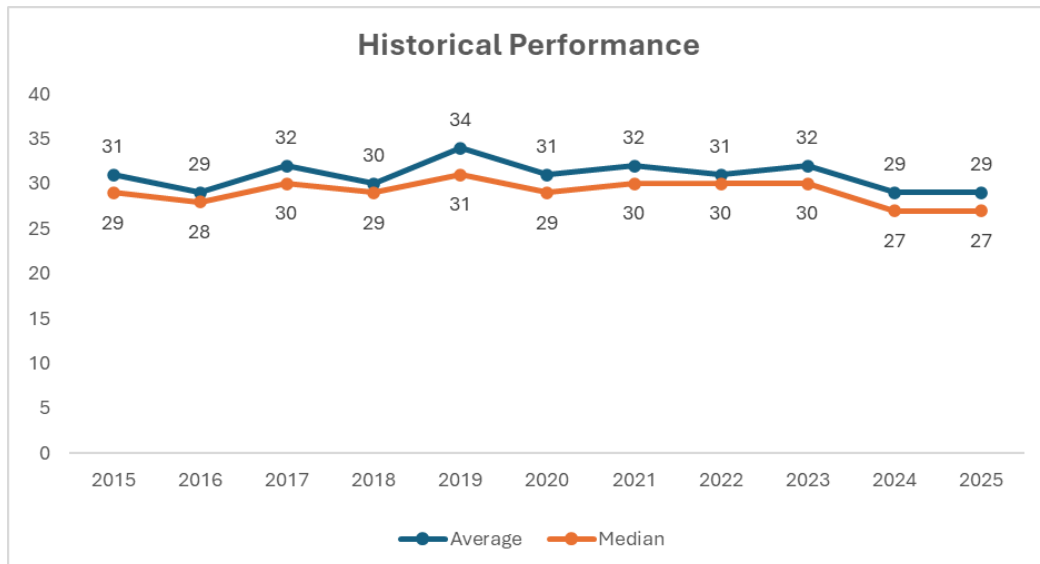
1 validation practices were not in place until 2015 and therefore only data from
2 2015 and beyond is reported here for consistency and comparability.

3 Over the timeframe of 2015 through 2025, there has been a 6 percent
4 reduction in total average response time, from 31 minutes end of year
5 average 2015 to 29 minutes in 2025. The median response time also
6 reduced by 7 percent from 29 minutes end of year 2015 to 27 minutes in
7 2025.

8 Since 2015, PG&E’s historical performance has been within the first
9 quartile and has been in the first decile for several years when
10 measuring percentage of response times within 60 minutes, which is the
11 industry benchmarkable definition.

12 Metric performance has been driven by accurately predicting when large
13 volumes of calls will occur (based on weather forecasts), proactive
14 scheduling of resources for emergency response, cross-functional
15 coordination across PG&E to train non-traditional stand-by staff, availability
16 of resources for weather days and improved understanding of shifts in storm
17 fronts that impact the system.

FIGURE 3.12-1
ELECTRIC EMERGENCY RESPONSE TIME HISTORICAL DATA
(2015-2025)



Note: The data in this figure is subject to change based on continuing review of prior period usages.

1 **2. Data Collection Methodology**

2 The metric performance data is captured and stored in the Outage
3 Information System (OIS) database. Each emergency call has a time
4 stamp. The start time of an electric emergency call involves receipt by utility
5 personnel and entry into the OIS database (creation of a tag). The tag is
6 created in the OIS database when PG&E personnel are on the phone with
7 the first responder dispatch agency (there is a direct PG&E Emergency line
8 into Gas Dispatch, where all emergency calls are routed). This process
9 removes the delay between the time the call is received and entered into the
10 system, and the raw data is then reviewed for duplicate entries, which are
11 cancelled (if found). The timestamp of when PG&E personnel respond on
12 site is primarily when they select the “onsite” button on their mobile data
13 terminals, which marks the completion of the response. If there is a
14 discrepancy or uncertainty, our Electric Dispatch team will validate the exact
15 arrival time by leveraging Global Positioning System data from our
16 employee’s vehicles and/or mobile data terminals. The response time in
17 minutes is calculated by the difference between the two timestamps. From
18 each call’s response time, the average and median time is calculated for all
19 calls.

20 **3. Metric Performance for the Reporting Period**

21 In 2025 average Emergency Operations emergency response time was
22 29 minutes and median response time was 27 minutes. This is considered
23 strong performance, as the corresponding benchmarkable calculation,
24 percent response time within 60 minutes, remains at the top of industry
25 performance.

26 **C. (3.12) 1-Year and 5-Year Target**

27 **1. Updates to 1- and 5-Year Targets Since Last Report**

28 There have been no changes to 1- and 5 -Year targets since the last
29 report filing.

2. Target Methodology

To establish the 1 -Year and 5 -Year targets, PG&E considered the following factors:¹

- Historical Data and Trends: Comparable data is available starting in 2015 although historical benchmarking trends (under alternative definition) are informative back to 2012. This historical data context confirms PG&E’s current results are improved, sustained, and reasonably considered strong performance, which has informed the target setting direction to “maintain;”
- Benchmarking: Industry benchmarking is available under the emergency response time measure calculated as percent time responding on site within 60 minutes. PG&E is first quartile within this benchmark, and has used this industry data as a key datapoint to inform target setting:
 - To do this, PG&E used available industry benchmark data in 2021 to set its initial electric emergency response targets for this metric. Specifically, these estimated values represent the point at which, when exceeded, performance would move out of first quartile and into second quartile;
 - PG&E’s intent is to stay in first quartile performance. Given the context that benchmarking provides, PG&E targets are meant to maintain current performance at levels better than the first quartile threshold, and would consider a performance change on the magnitude of exceeding these targets (i.e., moving into a worse estimated quartile, a signal of concern);
 - In other words, target values in this case represent performance levels that PG&E does not want to exceed or move performance towards. Values should not be interpreted as a plan for or expectation of worsening performance;
- Regulatory Requirements: None;
- Attainable With Known Resources/Work Plan: Yes;

¹ Targets represent values that serve as appropriate indicator lights to signal a review of potential performance issues. Targets should not be interpreted as intention to worsen performance, as further described below.

- 1 • Appropriate/Sustainable Indicators for Enhanced Oversight and
2 Enforcement: Historical data and trends confirm that maintaining
3 estimated first quartile performance is a sustainable target in both the
4 1-year and 5-year timeframes. A change in performance on the
5 magnitude of reaching the targets (i.e., performance moving into the
6 estimated second quartile) is an appropriate indicator light to examine
7 potential performance issues as PG&E's intent is to maintain current
8 practices, past improvements, and mitigate any future operational
9 impacts that may arise.
- 10 • Other Considerations: None.

11 3. 2026 Target

12 The 2026 target is to remain better than 44 minutes for average
13 emergency response time and better than 43 minutes for median
14 emergency response time. Targets are based on maintaining first quartile
15 performance as benchmarked in 2021.

16 4. 2030 Target

17 The 2030 target is to remain better than 44 minutes for average
18 emergency response time and better than 43 minutes for median
19 emergency response time. Targets are based on maintaining first quartile
20 performance.

21 D. (3.12) Performance Against Target

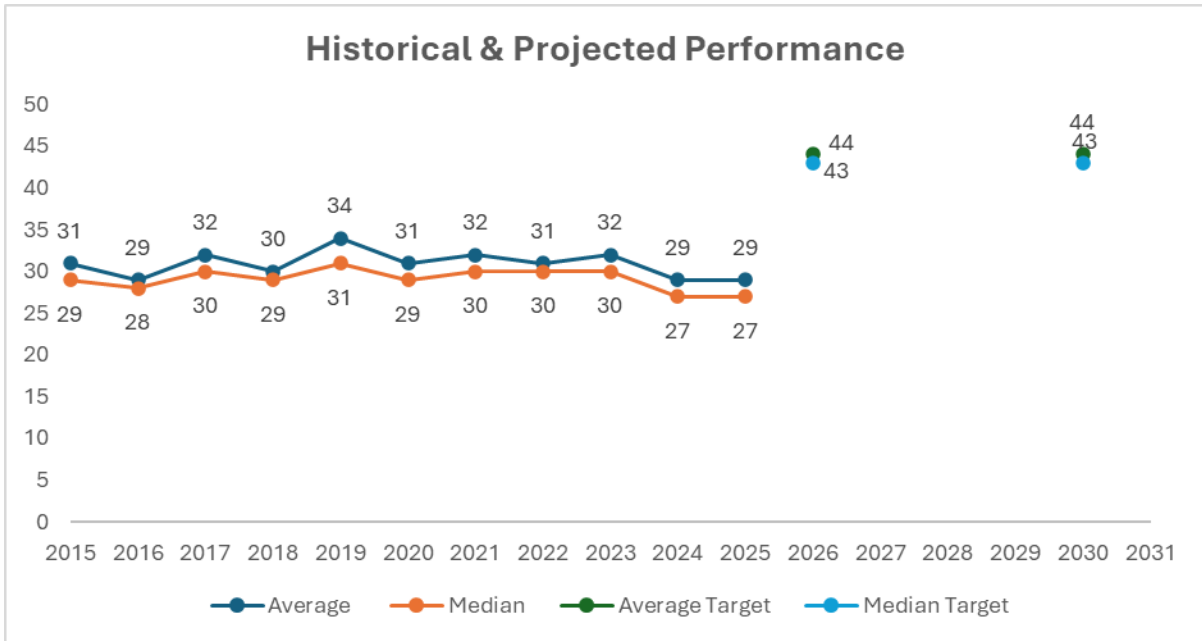
22 1. Progress Towards the 1-Year Target

23 As demonstrated in Figure 3.12-2 below, PG&E saw an average of
24 29 response minutes and a median of 27 response minutes in 2025 which is
25 consistent with PG&E's 1-year target.

26 2. Progress Towards the 5-Year Target

27 As discussed in Section E below, PG&E has deployed two programs to
28 maintain or improve long term performance of this metric to meet PGE&E's
29 5-year performance target.

**FIGURE 3.12-2
ELECTRIC EMERGENCY RESPONSE TIME HISTORICAL AND PROJECTED DATA**



1 **E. (3.12) Current and Planned Work Activities**

2 PG&E plans to perform the following actions in 2026 to maintain its top
3 quartile performance:

- 4 • Storm Event Scheduling
- 5 – In 2025, Electric Dispatch continued to refine its electric emergency
6 stand-by resource scheduling systems and process. The goal was to
7 optimize the number of stand-by resources available in a geographic
8 area, at the right time, to the forecasted system impacts.
- 9 – In 2026, PG&E will continue to evolve its stand-by resource scheduling
10 systems and processes based on learnings from 2025 and previous
11 years.

- 12 • Blue-Sky Call Out Improvements
- 13 In 2025, PG&E leveraged its Lean problem solving process to identify
14 opportunities to incrementally improve after-hours electric emergency call
15 out performance.

16 In 2026, it will fully operationalize a systematic after-hours enhancement
17 to electronically contact first responders in parallel, instead of calling them in
18 a specific order, when responding to public agencies for utility emergencies.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.13
NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS
(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
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NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 3.13**
4 **NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS**
5 **(DISTRIBUTION)**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.13) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metrics (SOM) 3.13 – the Number of California
11 Public Utilities Commission (CPUC) Reportable Ignitions in High Fire Threat
12 Districts (HFTD) Areas (Distribution) is defined as:

13 *The number of CPUC-reportable ignitions involving overhead*
14 *distribution circuits in HFTD Areas.*

15 *A CPUC-Reportable Ignition refers to a fire incident where the following*
16 *three criteria are met: (1) ignition is associated with Pacific Gas and Electric*
17 *Company (PG&E) electrical assets, (2) something other than PG&E facilities*
18 *burned, and (3) the resulting fire travelled more than one linear meter from*
19 *the ignition point.¹*

20 For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

21 PG&E provides the CPUC with annual ignition data in the Fire Incident
22 Data Collection Plan, to the Office of Energy Infrastructure and Safety
23 quarterly via quarterly geographic information system, data reporting, in
24 quarterly Wildfire Mitigation Plan (WMP) updates, and the Safety
25 Performance Metrics Report.

26 **2. Introduction of Metric**

27 The number of CPUC-reportable ignitions in HFTDs provides one way to
28 gauge the level of wildfire risk that customers and communities are exposed
29 to from overhead distribution assets. PG&E's objective is to reduce the
30 number of CPUC reportable ignitions that may trigger a catastrophic wildfire.

1 Please see CPUC Decision (D.) 14-02-015, issued February 5, 2014 for additional details.

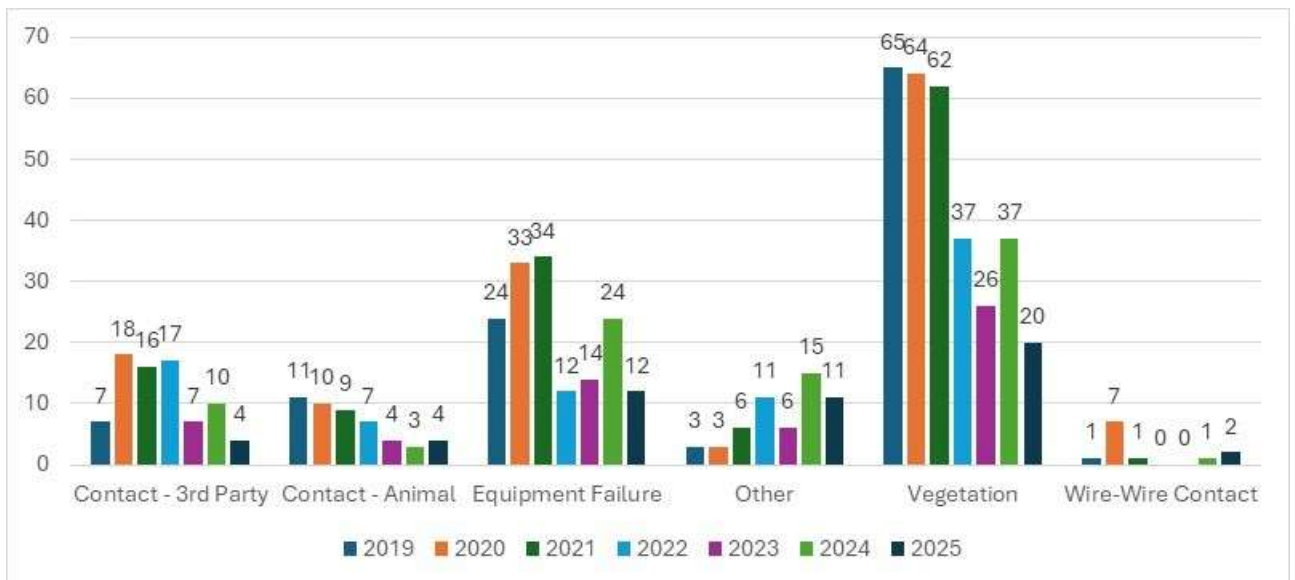
1 **B. (3.13) Metric Performance**

2 **1. Historical Data (2015 – 2025)**

3 PG&E implemented the Fire Incident Data Collection Plan in response
4 to D.14-02-015 in June 2014. PG&E’s Ignitions Tracker includes all
5 CPUC-reportable ignitions from June 2014 to present. The 2014 data does
6 not represent a complete year and is excluded in this analysis.

7 PG&E’s overhead distribution circuits traverse approximately
8 25,000 miles of terrain in the HFTD areas where the overhead conductor is
9 primarily bare wire, supported by structures consisting of poles, cross arms,
10 associated insulators, and operating equipment such as transformers, fuses
11 and reclosers. The main causes of CPUC-reportable ignitions have been
12 collected and classified. These fall into six broad categories: vegetation
13 contact, equipment failure, third-party contact, animal contact, wire to wire
14 contact, and other causes. The counts for 2019 through 2025, are shown in
15 the graph below, highlighting the degree of variability that occurs from year
16 to year relative to each category.

**FIGURE 3.13-1
DISTRIBUTION HISTORIC PERFORMANCE BY SUSPECTED CAUSE**



17 There is also a seasonal pattern to the ignition events as shown in the
18 chart of ignitions by month below for each of the years from 2019 through
19 2025.

**FIGURE 3.13-2
HISTORIC PERFORMANCE BY YEAR/MONTH**

Month	2019	2020	2021	2022	2023	2024	2025
January	0	0	19	2	0	0	1
February	0	6	2	5	8	2	0
March	2	3	5	4	2	4	1
April	4	3	7	9	6	2	1
May	8	8	16	11	4	10	9
June	15	26	23	14	2	13	12
July	25	24	25	12	8	20	14
August	13	27	17	10	14	10	8
September	20	17	7	9	8	13	6
October	12	16	6	7	2	9	1
November	12	2	0	1	2	5	0
December	2	3	1	0	1	2	0
Total	113	135	128	84	57	90	53

Note: The Ignition Investigation CPUC Reportable counts are subject to potential changes as new findings emerge during the ongoing investigation process. Incidents and Data are subject to change as there may be additional findings and data gathered throughout the investigation process. In this report, 2015, 2016, 2018, 2019-2021, and 2024 were updated.

1 **2. Data Collection Methodology**

2 Data will be collected per PG&E’s Fire Incident Data Collection Plan
 3 (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of
 4 unique HFTD CPUC-reportable ignitions attributable to the distribution asset
 5 class with overhead construction types.

6 The following ignition events captured by PG&E’s Fire Incident Data
 7 Collection Plan will be excluded for this metric:

- 8 • Duplicate events;
- 9 • Ignitions that do not meet CPUC reporting criteria;
- 10 • Ignition events outside of Tier 2 and Tier 3 HFTD;
- 11 • Transmission ignitions; and
- 12 • Ignitions attributable to underground or pad-mounted assets as these
 13 are not associated overhead assets. (Ignitions caused by non-overhead
 14 assets in HFTD are rare and, as the fires are often contained to the
 15 asset, pose less of a wildfire risk.)

16 **3. Metric Performance for the Reporting Period**

17 PG&E finished 2025 with 53 CPUC reportable ignitions in HFTD
 18 attributable to overhead distribution assets. These results are lower than

1 reported for the same time period last year (90 ignitions) and the
2 three-previous-year average (77 ignitions).

3 Most importantly, PG&E has observed 34 ignitions where the Fire
4 Potential Index (FPI) Rating was in R3 or greater conditions. This number is
5 slightly lower than the 3-year previous average (35 ignitions). We observed
6 an earlier season start, but fire weather remained relatively mild for the
7 remainder of the year and we saw lower than the three-year average
8 reportable ignitions and reportable ignitions in R3 or greater conditions
9 between August and October.

10 PG&E is dedicated to eliminating ignition events when and where they
11 represent wildfire risk. Please see the Target Methodology section for an
12 overview of our FPI model and our strategy to focus operational mitigations,
13 like Enhanced Powerline Safety Settings (EPSS), on reducing ignitions
14 where consequences are more likely.

15 **C. (3.13) 1-Year Target and 5-Year Target**

16 **1. Updates to 1- and 5-Year Targets Since Last Report**

17 PG&E proposes no changes to the 1 and 5-year targets for this period.
18 PG&E has set the 2025 and 2029 upper and lower limit target ranges to
19 account for the previous 5 years of actual results and variability driven by
20 weather and external factors.

21 PG&E remains focused on reducing those ignitions in R3+ conditions
22 and, as future strategies with direct ignition impact emerge, these targets will
23 be reevaluated.

24 **2. Target Methodology**

25 The two major programs that most directly impact ignition reduction in
26 the near-term are Public Safety Power Shutoff (PSPS) and EPSS. Other
27 important resiliency programs like undergrounding, system hardening, and
28 vegetation management (VM) will have an impact as multiple years of
29 cumulative work are completed.

30 PG&E has observed success with EPSS in terms of mitigating ignitions
31 in R3+ FPI conditions. These ignitions in R3+ conditions represent all
32 historical reportable ignitions resulting in a fatality, all ignitions over
33 100 acres in size, and 99 percent of reportable ignitions where a structure

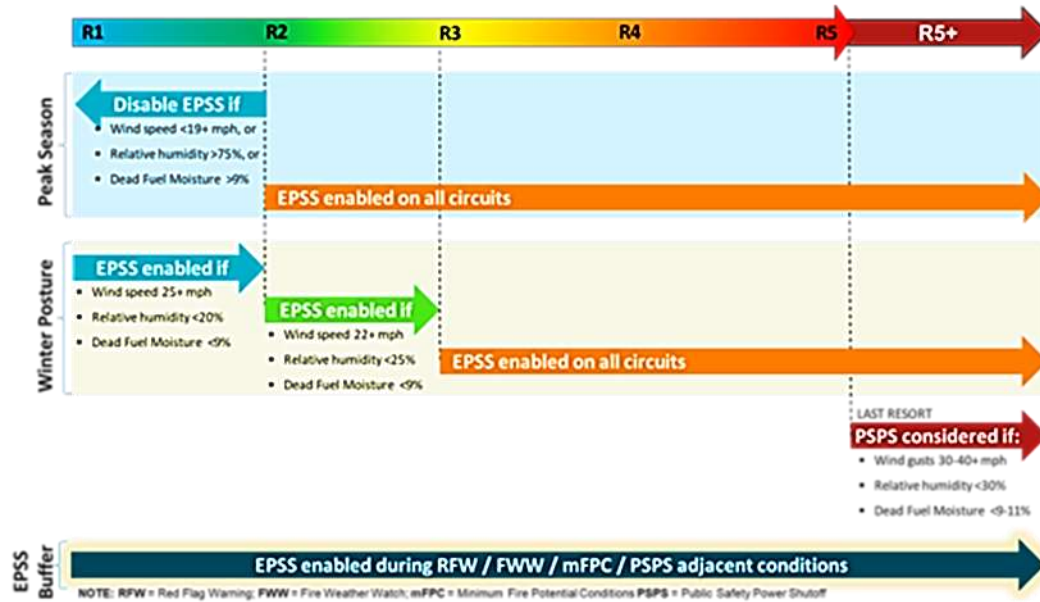
1 was destroyed between 2018 and 2020. See Figure 3.13-3 for fire statistics
2 by FPI rating.

**FIGURE 3.13-3
2018-2020 HFTD OVERHEAD REPORTABLE IGNITION STATISTICS
BY FPI, ALL ASSET CLASSES**

	R2+	R3+
% of Total Reportable Ignitions in HFTD	84%	60%
% of Wildfires >10 Acres	81%	71%
% of Wildfires >100 Acres	100%	100%
% of Total Structures Destroyed	100%	99%
% of Total Fatalities	100%	100%

3 In 2022, PG&E enabled EPSS technology on over 1,000 circuits,
4 protecting approximately 44,000 overhead distribution miles in our service
5 territory, including all distribution milage within HFTD. We also refined when
6 to enable this tool to mitigate fires of consequence by targeting the right
7 meteorological conditions. When a circuit is forecasted to be in FPI
8 conditions at a specific threshold based on peak season or winter posture,
9 EPSS is enabled on protective devices. See Figure 3.13-4 for details on this
10 enablement criteria.

**FIGURE 3.13-4
EPSS ENABLEMENT CRITERIA BASED ON FPI AND SEASON POSTURE**



1 In 2023, PG&E expanded on the capabilities of this program to reduce
 2 ignitions where and when they matter by layering additional system
 3 protection strategies to complement the capabilities of EPSS, including
 4 installing a Downed Conductor Detection (DCD) algorithm on recloser
 5 controllers.

6 PG&E expects continued success with the EPSS Program to reduce
 7 ignitions of consequence in 2026 and is actively exploring additional layers
 8 of protection through technology deployment to further reduce risk (please
 9 see [Current and Planned Work Activities](#)).

10 In 2024, PG&E established a taskforce to identify immediate actions to
 11 mitigate in light of the rising exposure (that manifested into increased
 12 ignition counts) and perform a cause evaluation to identify the root and
 13 contributing causes to an increase in ignitions throughout the year.

14 In 2025, PG&E established an additional proactive ignition mitigation
 15 taskforce to respond to wildfire risks highlighted by the January 2025
 16 wildfires in Southern California as well as other emerging risks identified
 17 throughout the 2024 and 2025 wildfire seasons.

18 However, ignition counts (in both low and potentially high consequence
 19 environments) are dependent on weather conditions and are highly variable.

1 As a result, PG&E forecasts a range of 70 to 128 reportable ignitions to
2 account for variability.

3 To establish the 1-year and 5-year targets, PG&E considered the
4 following factors:

- 5 • Historical Data and Trends: PG&E has layered significant wildfire
6 mitigation strategies over the past 8 years (like EPSS) and, outside of
7 PG&E's own ignition record, there is no comparable historical data to
8 help guide in target setting. PG&E is utilizing the previous 5-years worth
9 of ignition actuals (2020 – 2024) to propose 2026 and 2030 target
10 setting;
- 11 • Benchmarking: PG&E benchmarks extensively with other utilities in
12 terms of wildfire risk and ignition reduction. Specifically, PG&E reviews
13 utility ignition trends (where available) and analyzes the risk associated
14 large utility wildfires around the world;
- 15 • Regulatory Requirements: D.14-02-015;
- 16 • Attainable Within Known Resources/Work Plan: Yes;
- 17 • Appropriate/Sustainable Indicators for Enhanced Oversight and
18 Enforcement: The targets for this metric are suitable for Enhanced
19 Oversight and Enforcement as they consider the potential for an
20 increase in severe weather events due to climate change; and
- 21 • Other Qualitative Considerations: The target range takes consideration
22 for some variability in weather.

23 3. 2026 Target

24 The 2026 target is 70-128 ignitions. The upper end of this range
25 represents the 5-year previous average from 2024 (99 ignitions) with an
26 additional full standard deviation (29 ignitions) for those same years to
27 account for variability. The lower end of this range represents a full
28 standard deviation reduction to that same average.

29 4. 2030 Target

30 The 2030 target is 70-128 ignitions. The upper end of this range
31 represents the 5-year previous average from 2024 (99 ignitions) with an
32 additional full standard deviation (29 ignitions) for those same years to
33 account for variability. The lower end of this range represents a full

1 standard deviation reduction to that same average. Additional time and
2 maturity of PG&E's wildfire mitigations strategies will allow PG&E to reduce
3 ignitions in R3+ conditions and forecast the effectiveness of the EPSS
4 Program to help inform long-term target ranges.

5 **D. (3.13) Performance Against Target**

6 **1. Progress Towards the 1-Year Target**

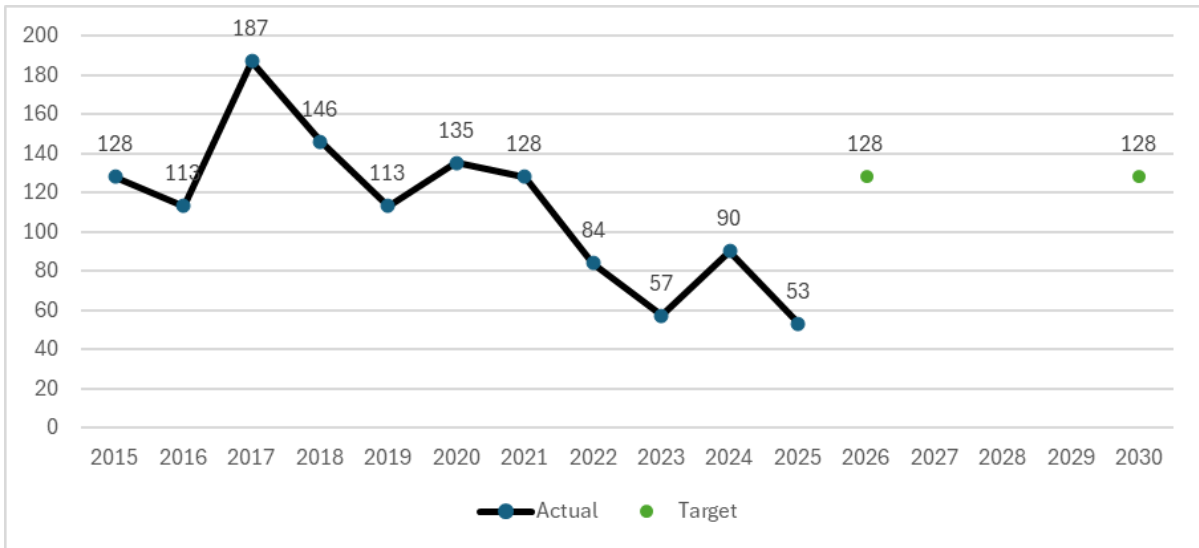
7 As demonstrated in Figure 3.13-6 below, PG&E ended this reporting
8 period with 53 ignitions. We completed 2025 below our target of 70 – 128
9 ignitions.

10 PG&E remains focused on reducing those ignitions in R3+ conditions
11 and, as future strategies with direct ignition impact emerge, these targets will
12 be reevaluated.

13 **2. Progress Towards the 5-Year Target**

14 PG&E is on track to reach our 5-year goal. Outlined in Section E below,
15 PG&E continues to deploy several programs outside of the EPSS Program
16 designed to improve the long-term performance of ignitions in R3+
17 conditions (where and when they matter) and further our goals of ending
18 catastrophic wildfires associated with utility assets. PG&E can expect to see
19 improved performance on this metric through continual execution of the
20 WMP and maturation of key wildfire mitigation strategies, including:
21 Maturation of the EPSS Program, VM, and Maturation of the Continuous
22 Monitoring (CM) Program.

**FIGURE 3.13-5
HISTORICAL PERFORMANCE (2015-2025)
AND TARGETS (2026 AND 2030)**



E. (3.13) Current and Planned Work Activities

PG&E can expect to see improved performance on this metric through continual execution of the WMP and maturation of key wildfire mitigation strategies, including:

- Maturation of the EPSS Program: In July 2021, to address the dynamic climate challenge, we implemented the EPSS Program on approximately 11,500 miles of distribution circuits, or 45 percent of the circuits in HFTD areas. With EPSS, we engineered changes to our electrical equipment settings so that if an object such as vegetation contacts a distribution line, power is automatically shut off within 1/10th of a second, reducing the potential for an ignition. EPSS enabled settings provide a layer of protection on days when the wind speeds are low. EPSS is especially important during hot dry summer days when there are low winds. Continued low relative humidity, low fuel moistures levels, and areas where the volume of dry vegetation is in close proximity to the distribution lines, increases the risk of an ignition becoming a large wildfire.

In 2022, we expanded the EPSS scope to all primary distribution conductors in High Fire Risk Area (HFRA) areas in our service territory, as well as select non HFRA areas. In concert with this expansion of the

1 program, PG&E modified enablement criteria (improving risk reduction and
2 reliability).

3 In 2023, PG&E implemented a DCD algorithm on recloser controllers to
4 mitigate risk of low current fault conditions, also referred to as
5 high-impedance faults.

6 In 2024, PG&E matured high-impedance fault protection by adjusting
7 Sensitive Ground Fault relay settings and piloting new technology to add
8 DCD-like protection to the small number of circuit miles where we were not
9 capable of implementing DCD. [This work has continued in 2025 and we](#)
10 [have continued to review ignitions where EPSS was enabled and look for](#)
11 [refinements in protection schemes to reduce high-impedance fault ignitions.](#)

12 Please see Section 8.1.8.1.1, Protective Equipment and Device Settings
13 in PG&E's 2023-2025 WMP, and Sections 8.2.8.1, Installation of System
14 Automation Equipment – Distribution Protective Devices, and 8.2.10, Other
15 Grid Topology Improvements to Minimize Risk of Ignitions, in PG&E's
16 2026-2028 WMP for additional details.

- 17 • Public Safety Power Shut Off: PSPS is a wildfire mitigation strategy, first
18 implemented in 2019, to reduce powerline ignitions during severe weather by
19 proactively de-energizing powerlines (remove the risk of those powerlines
20 causing an ignition) prior to forecasted wind events when humidity levels and
21 fuel conditions are conducive to wildfires. PG&E's focus with the PSPS
22 Program is to mitigate the risks associated with a catastrophic wildfire and to
23 prioritize customer safety. In 2021, PG&E continued to make progress to its
24 PSPS Program to mitigate wildfire risk, including updating meteorology
25 models and scoping processes. In 2023, PG&E continued a multi-year effort
26 to install additional distribution sectionalizing devices, Fixed Power Solutions,
27 and other mitigations targeted at reducing the risk of wildfire. In 2024, we
28 updated our thresholds utilizing new and improved risk models.

29 Please see Section 9, PPS, Including Directional Vision For PPS in
30 PG&E's 2023-2025 WMP and Section 7, Public Safety Power Shutoff, in
31 PG&E's 2026-2028 WMP for additional details.

- 32 • Grid Design and System Hardening: PG&E's broader grid design program
33 covers several significant programs to reduce ignition risk, called out in detail
34 in PG&E's 2023 WMP. The largest of these programs is the System

1 Hardening Program which focuses on the mitigation of potential catastrophic
2 wildfire risk caused by distribution overhead assets. In 2023, we rapidly
3 expanded our system hardening efforts by:

- 4 – Completing 420 circuit miles of system hardening work, which includes
5 overhead system hardening, undergrounding and removal of overhead
6 lines in HFTD or buffer zone areas;
- 7 – Completing at least 350 circuit miles of undergrounding work, including
8 Butte County Rebuild efforts and other distribution system hardening
9 work;
- 10 – In 2024, PG&E completed ~250 miles of undergrounding; and
- 11 – In 2025, PG&E completed ~350 miles of undergrounding.

12 As we look to 2026, PG&E is targeting 360 miles of undergrounding as
13 part of the 10,000 Mile Undergrounding Program. This system hardening
14 work done at scale is expected to have a material impact on ignition
15 reduction.

16 Please see Section 8.2, Grid Design and System Hardening Mitigations
17 in PG&E's 2026-2028 WMP for additional details.

- 18 • Vegetation Management: We restructured our VM Program based on a
19 risk-informed approach.

20 Around 2022, data and analysis demonstrated that the Enhanced
21 Vegetation Management (EVM) Program risk reduction is less than EPSS
22 and additional Operational Mitigations. As a result, we transitioned the EVM
23 Program to three new risk-informed VM programs described below, and
24 future described in Section 8.2.2, Vegetation Management and Inspections,
25 in PG&E's 2023–2025 WMP.

- 26 – Focused Tree Inspections (FTI): We developed specific areas of focus
27 (referred to as Areas of Concern), primarily in the HFRA, where we will
28 concentrate our efforts to inspect and address high-risk locations, such
29 as those that have experienced higher volumes of vegetation damage
30 during PSPS events, outages, and/or ignitions.
- 31 – VM for Operational Mitigations: This program is intended to help reduce
32 outages and potential ignitions using a risk informed, targeted plan to
33 mitigate potential vegetation contacts based on historic vegetation
34 caused outages on EPSS-enabled circuits. We will initially focus on

1 mitigating potential vegetation contacts in circuit protection zones that
2 have experienced vegetation caused outages. Scope of work will be
3 developed by using EPSS and historical outage data and vegetation
4 failure from the Wildfire Distribution Risk Model v3 risk model.

5 EPSS-enabled devices vegetation outages extent of condition
6 inspections may generate additional tree work.

- 7 – Tree Removal Inventory (TRI): This is a long-term program intended to
8 systematically work down trees that were previously identified through
9 EVM inspections. We will develop annual risk-ranked work plans and
10 mitigate the highest risk-ranked areas first and will continue monitor the
11 condition of these trees through our established inspection programs.

12 In 2026, PG&E continues to drive towards a more risk informed
13 approach, while adjusting its program based on external feedback to
14 minimize customer touchpoints. As a result, PG&E consolidated its
15 programs starting in 2026. PG&E's FTI program now is incorporated into its
16 normal Routine and Hazard program, with those elevated inspections
17 conducted at the same time. The VM for Operational Mitigations is
18 incorporated into normal operating procedures, by further addressing
19 vegetation contact based on historical outages beyond EPSS enabled
20 circuits, but also other weather driven events like PSPS. Lastly, the TRI
21 trees will also be incorporated into its normal Routine and Hazard program
22 to inspect and determine the appropriate action to address these trees.
23 PG&E's VM activities are further described in Section 9.2, Vegetation
24 Management and Inspections, in PG&E's 2026-2028 WMP.

- 25 • Maturation of the Continuous Monitoring Program: In 2025, PG&E expanded
26 deployment of our CM Program by increasing installation of Gridscope
27 sensors, Early Fault Detection, Distribution Fault Anticipation, line sensors,
28 and SmartMeter machine learning solutions. The CM Program has enabled
29 identification of faults and defects consistent with ignition failure modes
30 before they fail and have the potential to cause an ignition. These include,
31 among other failure modes, melted or degraded connectors and overloaded
32 equipment. PG&E is prioritizing installation of the CM technologies using
33 wildfire risk buydown curves, ignition, and failure history.

1 Please see Section 10.3.2 in PG&E's 2026-2028 WMP for additional
2 details.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.14
PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN
HFTD AREAS
(DISTRIBUTION)

PACIFIC GAS AND ELECTRIC COMPANY
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12 Public Utilities Commission (CPUC) Reportable Ignitions in High Fire Threat
13 Districts (HFTD) areas (Distribution) is defined as:

14 *The number of CPUC-reportable ignitions involving overhead (OH)*
15 *distribution circuits in HFTD areas divided by circuit miles of OH distribution*
16 *lines in HFTD multiplied by 1000 miles (ignitions per 1000 HFTD circuit*
17 *miles).*

18 *A CPUC-Reportable Ignition refers to a fire incident where the following*
19 *three criteria are met: (1) Ignition is associated with PG&E electrical assets,*
20 *(2) something other than PG&E facilities burned, and (3) the resulting fire*
21 *travelled more than one linear meter from the ignition point.¹*

22 For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

23 PG&E provides the CPUC with annual ignition data in the Fire Incident
24 Data Collection Plan, to the Office of Energy Infrastructure and Safety
25 quarterly via quarterly geographic information system, data reporting, in
26 quarterly Wildfire Mitigation Plan updates, and the Safety Performance
27 Metrics Report.

28 **2. Introduction of Metric**

29 The number of CPUC-reportable Ignitions in HFTDs, normalized by
30 circuit mileage, provides one way to gauge the level of wildfire risk that
31 customers and communities are exposed to from OH distribution assets.

1 Please CPUC Decision (D.) 14-02-015, issued February 5, 2014, for additional details.

1 PG&E's objective is to reduce the number of CPUC-reportable ignitions that
2 may trigger a catastrophic wildfire.

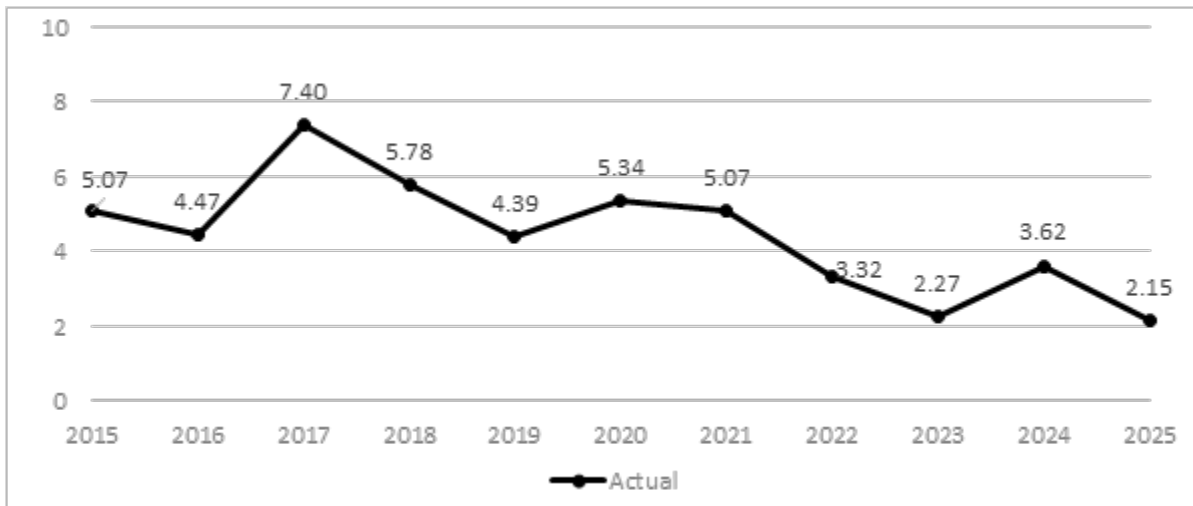
3 **B. (3.14) Metric Performance**

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6 to D.14-02-015, in June 2014 and our record, the Ignitions Tracker, includes
7 all CPUC-reportable ignitions from June 2014 to present. The 2014 data
8 does not represent a complete year and is excluded in this analysis.

9 PG&E's OH distribution circuits traverse approximately 25,000 miles of
10 terrain in the HFTD areas where the OH conductor is primarily bare wire,
11 supported by structures consisting of poles, cross arms, associated
12 insulators, and operating equipment such as transformer, fuses and
13 reclosers. Given the volume of equipment within the 25,000 miles of HFTD,
14 the annual number of CPUC-reportable ignitions is too low to detect any
15 statistical pattern.

**FIGURE 3.14-1
HISTORICAL PERFORMANCE
(2015-2025)**



Note: The Ignition Investigation CPUC Reportable counts are subject to potential changes as new findings emerge during the ongoing investigation process. Incidents and Data are subject to change as there may be additional findings and data gathered throughout the investigation process. In this report, 2024 was updated.

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- 11 • Transmission Ignitions; and
- 12 • Ignitions attributable to underground or pad mounted assets as these
13 are not associated OH assets. (Ignitions caused by non-OH assets in
14 HFTD are rare and, as the fires are often contained to the asset, pose
15 less of a wildfire risk.)

16 The circuit mileage utilized to calculate the 2015-2022 performance of
17 this metric originates from PG&E’s Electrical Asset Data Reports, refreshed
18 December 2022. The 2023-2024 performance and targets are based on an
19 updated sum of overhead circuit mileage, refreshed in 2023 and is refreshed
20 each year based on overhead circuit mileage.

21 **3. Metric Performance for the Reporting Period**

22 PG&E finished 2025 with 53 CPUC reportable ignitions in HFTD
23 attributable to overhead distribution assets (corresponding to a rate of
24 2.15 ignitions per 1,000 circuit miles). These results are lower than reported
25 for the same time period last year (90 ignitions) and the three-previous-year
26 average (77 ignitions).

27 Most importantly, PG&E has observed 34 ignitions where the Fire
28 Potential Index Rating (FPI) was in R3 or greater conditions. This number is
29 slightly lower than the 3-year previous average (35 ignitions). We observed
30 an earlier season start, but fire weather remained relatively mild for the
31 remainder of the year and we saw lower than the three-year average
32 reportable ignitions and reportable ignitions in R3 or greater conditions
33 between August and October.

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2 represent wildfire risk. Please see the Target Methodology section for an
3 overview of our FPI model and our strategy to focus operational mitigations,
4 like Enhanced Powerline Safety Settings (EPSS), on reducing ignitions
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15 account for the previous 5 years of actual results and variability driven by
16 weather and external factors.

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22 the near-term are Public Safety Power Shut Off (PSPS) and EPSS. Other
23 important resiliency programs like undergrounding, system hardening, and
24 vegetation management (VM) will have an impact as multiple years of
25 cumulative work are completed.

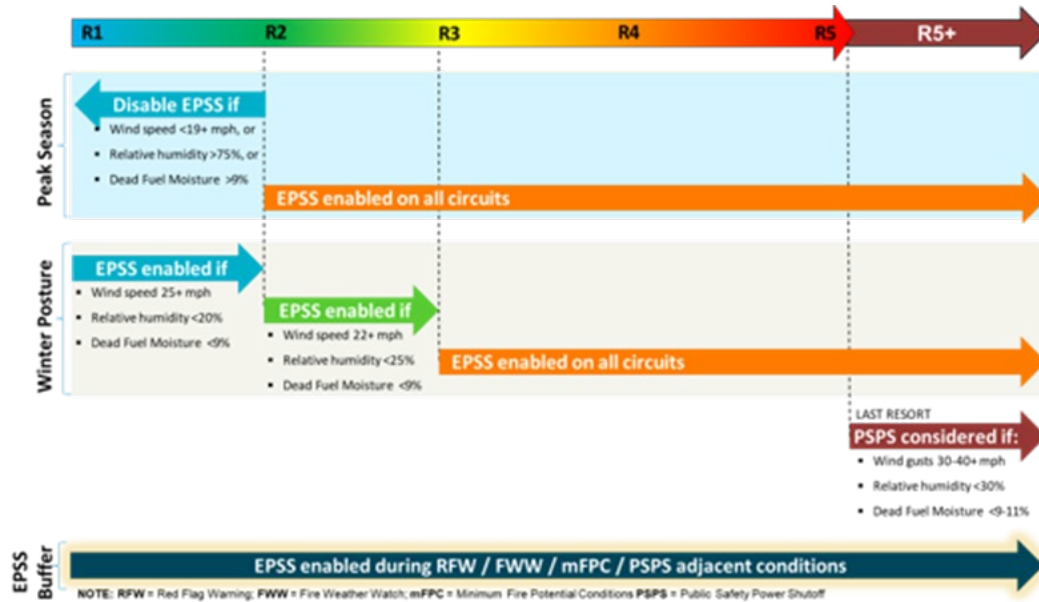
26 PG&E has observed success with EPSS in terms of mitigating ignitions
27 in R3+ FPI conditions. These ignitions in R3+ conditions represent all
28 historical reportable ignitions resulting in a fatality, all ignitions over
29 100 acres in size, and 99 percent of reportable ignitions where a structure
30 was destroyed [between 2018 and 2020](#). See Figure 3.14-2 for fire statistics
31 by FPI rating.

**FIGURE 3.14-2
2018-2020 HFTD OVERHEAD REPORTABLE IGNITION STATISTICS BY FPI,
ALL ASSET CLASSES**

	R2+	R3+
% of Total Reportable Ignitions in HFTD	84%	60%
% of Wildfires >10 Acres	81%	71%
% of Wildfires >100 Acres	100%	100%
% of Total Structures Destroyed	100%	99%
% of Total Fatalities	100%	100%

1 In 2022, PG&E enabled EPSS technology on over 1,000 circuits,
 2 protecting approximately 44,000 overhead distribution miles in our service
 3 territory, including all distribution milage within HFTD. We also refined when
 4 to enable this tool to mitigate fires of consequence by targeting the right
 5 meteorological conditions. When a circuit is forecasted to be in FPI
 6 conditions at a specific threshold based on peak season or winter posture,
 7 EPSS is enabled on protective devices. See Figure 3.14-3 for details on this
 8 enablement criteria.

**FIGURE 3.14-3
EPSS ENABLEMENT CRITERIA BASED ON FIRE POTENTIAL INDEX AND SEASON POSTURE**



1 In 2023, PG&E expanded on the capabilities of this program to reduce
 2 ignitions where and when they matter by layering additional system
 3 protection strategies to complement the capabilities of EPSS, including
 4 installing a Downed Conductor Detection (DCD) algorithm on recloser
 5 controllers.

6 PG&E expects continued success with the EPSS Program to reduce
 7 ignitions of consequence in 2026 and is actively exploring additional layers
 8 of protection through technology deployment to further reduce risk (please
 9 see Current and Planned Work Activities).

10 In 2024, PG&E established a taskforce to identify immediate actions to
 11 mitigate in light of the rising exposure (that manifested into increased
 12 ignition counts) and perform a cause evaluation to identify the root and
 13 contributing causes to an increase in ignitions throughout the year.

14 In 2025, PG&E established an additional proactive ignition mitigation
 15 taskforce to respond to wildfire risks highlighted by the January 2025
 16 wildfires in Southern California as well as other emerging risks identified
 17 throughout the 2024 and 2025 wildfire seasons.

18 However, ignition counts (in both low and potentially high consequence
 19 environments) are dependent on weather conditions and are highly variable.

1 As a result, PG&E forecasts a range of 70 to 128 reportable ignitions to
2 account for variability.

3 To establish the 1-year and 5-year targets, PG&E considered the
4 following factors:

- 5 • Historical Data and Trends: PG&E has layered significant wildfire
6 mitigation strategies over the past 8 years (like EPSS) and, outside of
7 PG&E's own ignition record, there is no comparable historical data to
8 help guide in target setting. [PG&E is utilizing the previous 5-years worth
9 of ignition actuals \(2020-2024\) to propose 2026 and 2030 target setting;](#)
- 10 • Benchmarking: PG&E benchmarks extensively with other utilities in
11 terms of wildfire risk and ignition reduction. Specifically, PG&E reviews
12 utility ignition trends (where available) and analyzes the risk associated
13 with large utility wildfires around the world;
- 14 • Regulatory Requirements: D.14-02-015;
- 15 • Attainable Within Known Resources/Work Plan: Yes;
- 16 • Appropriate/Sustainable Indicators for Enhanced Oversight and
17 Enforcement: The targets for this metric are suitable for Enhanced
18 Oversight and Enforcement as they consider the potential for an
19 increase in severe weather events due to climate change; and
- 20 • Other Qualitative Considerations: The target range takes consideration
21 for some variability in weather.

22 **3. 2026 Target**

23 The 2026 target is [70-128 ignitions corresponding to a rate of
24 2.86 – 5.24 ignitions per 1,000 circuit miles](#)). The upper end of this range
25 represents the 5-year previous average [from 2024](#) (99 ignitions) with an
26 additional full standard deviation (29 ignitions) for those same years to
27 account for variability. The lower end of this range represents a full
28 standard deviation reduction to that same average.

29 **4. 2030 Target**

30 The 2030 target is [70-128 ignitions corresponding to a rate of
31 2.86 – 5.24 ignitions per 1,000 circuit miles](#)). The upper end of this range
32 represents the 5-year previous average [from 2024](#) (99 ignitions) with an
33 additional full standard deviation (29 ignitions) for those same years to

1 account for variability. The lower end of this range represents a full
2 standard deviation reduction to that same average. Additional time and
3 maturity of PG&E's wildfire mitigations strategies will allow PG&E to reduce
4 ignitions in R3+ conditions and forecast the effectiveness of the EPSS
5 Program to help inform long-term target ranges.

6 **D. (3.14) Performance Against Target**

7 **1. Progress Towards the 1-Year Target**

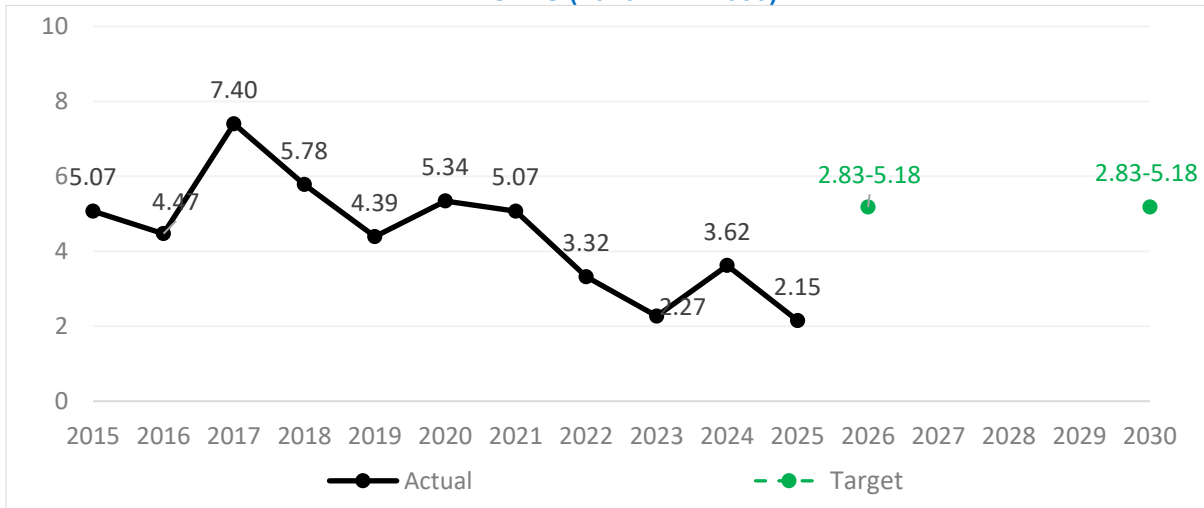
8 As demonstrated in Figure 3.13-5 below, PG&E ended this reporting
9 period with 53 ignitions (corresponding to a rate of 2.15 ignitions per 1,000
10 circuit miles). We completed 2025 below our target of 70 – 128 ignitions
11 with a rate of 2.15.

12 PG&E remains focused on reducing those ignitions in R3+ conditions
13 and, as future strategies with direct ignition impact emerge, these targets will
14 be reevaluated.

15 **2. Progress Towards the 5-Year Target**

16 PG&E is on track to reach our 5-year goal. Outlined in Section E below,
17 PG&E continues to deploy several programs outside of the EPSS Program
18 designed to improve the long-term performance of ignitions in R3+
19 conditions (where and when they matter) and further our goals of ending
20 catastrophic wildfires associated with utility assets. PG&E can expect to see
21 improved performance on this metric through continual execution of the
22 Wildfire Mitigation Plan (WMP) and maturation of key wildfire mitigation
23 strategies, including: Maturation of the EPSS Program, Vegetation
24 Management, and Maturation of the Continuous Monitoring Program.

**FIGURE 3.14-4
HISTORICAL PERFORMANCE (2015-2025) AND
TARGETS (2026 AND 2030)**



Note: Performance prior to 2021 is calculated using circuit mileage from 2021.

E. (3.14) Current and Planned Work Activities

PG&E can expect to see improved performance on this metric through continual execution of the Wildfire Mitigation Plan (WMP) and maturation of key wildfire mitigation strategies, including:

- Maturation of the EPSS Program: In July 2021, to address the dynamic climate challenge, we implemented the EPSS Program on approximately 11,500 miles of distribution circuits, or 45 percent of the circuits in HFTD areas. With EPSS, we engineered changes to our electrical equipment settings so that if an object such as vegetation contacts a distribution line, power is automatically shut off within 1/10th of a second, reducing the potential for an ignition. EPSS enabled settings provide a layer of protection on days when the wind speeds are low. EPSS is especially important during hot dry summer days when there are low winds. Continued low relative humidity, low fuel moistures levels, and areas where the volume of dry vegetation is in close proximity to the distribution lines, increases the risk of an ignition becoming a large wildfire.

In 2022, we expanded the EPSS scope to all primary distribution conductors in HFRA areas in our service territory, as well as select non HFRA areas. In

1 concert with this expansion of the program, PG&E modified enablement criteria
2 (improving risk reduction and reliability).

3 In 2023, PG&E implemented a DCD algorithm on recloser controllers to
4 mitigate risk of low current fault conditions, also referred to as high-impedance
5 faults.

6 In 2024, PG&E matured high-impedance fault protection by adjusting
7 Sensitive Ground Fault relay settings and piloting new technology to add
8 DCD-like protection to the small number of circuit miles where we were not
9 capable of implementing DCD. [This work has continued in 2025 and we have
10 continued to review ignitions where EPSS was enabled and look for refinements
11 in protection schemes to reduce high-impedance fault ignitions.](#)

12 Please see Section 8.1.8.1.1, Protective Equipment and Device Settings in
13 PG&E's 2023-2025 WMP, and Sections 8.2.8.1, Installation of System
14 Automation Equipment – Distribution Protective Devices, and 8.2.10, Other Grid
15 Topology Improvements to Minimize Risk of Ignitions, in PG&E's 2026-2028
16 WMP for additional details.

- 17 • Public Safety Power Shut Off (PSPS): PSPS is a wildfire mitigation
18 strategy, first implemented in 2019, to reduce powerline ignitions during
19 severe weather by proactively de-energizing powerlines (remove the risk of
20 those powerlines causing an ignition) prior to forecasted wind events when
21 humidity levels and fuel conditions are conducive to wildfires. PG&E's focus
22 with the PSPS Program is to mitigate the risks associated with a
23 catastrophic wildfire and to prioritize customer safety. In 2021, PG&E
24 continued to make progress to its PSPS Program to mitigate wildfire risk,
25 including updating meteorology models and scoping processes. In 2023,
26 PG&E continued a multi-year effort to install additional distribution
27 sectionalizing devices, Fixed Power Solutions, and other mitigations
28 targeted at reducing the risk of wildfire. In 2024, we updated our thresholds
29 utilizing new and improved risk models.

30 Please see Section 9, PSPS, Including Directional Vision for PSPS in
31 PG&E's 2023-2025 WMP and Section 7, Public Safety Power Shutoff, in
32 PG&E's 2026-2028 WMP for additional details.

- 33 • Grid Design and System Hardening: PG&E's broader grid design program
34 covers several significant programs to reduce ignition risk, called out in

1 detail in PG&E's 2023 WMP. The largest of these programs is the System
2 Hardening Program which focuses on the mitigation of potential catastrophic
3 wildfire risk caused by distribution overhead assets. In 2023, we rapidly
4 expanded our system hardening efforts by:

- 5 – Completing 420 circuit miles of system hardening work, which includes
6 overhead system hardening, undergrounding and removal of overhead
7 lines in HFTD or buffer zone areas;
- 8 – Completing at least 350 circuit miles of undergrounding work, including
9 Butte County Rebuild efforts and other distribution system hardening
10 work; and
- 11 – In 2024, PG&E completed ~250 miles of undergrounding.
- 12 – In 2025, PG&E completed ~350 miles of undergrounding.

13 As we look to 2026, PG&E is targeting 360 miles of undergrounding as
14 part of the 10,000 Mile Undergrounding Program. This system hardening
15 work done at scale is expected to have a material impact on ignition
16 reduction.

17 Please see Section 8.2, Grid Design and System Hardening Mitigations
18 in PG&E's 2026-2028 WMP for additional details.

- 19 • Vegetation Management: We restructured our VM Program based on a
20 risk-informed approach.

21 Around 2022, data and analysis demonstrated that the Enhanced
22 Vegetation Management (EVM) Program risk reduction is less than EPSS
23 and additional Operational Mitigations. As a result, we transitioned the EVM
24 Program to three new risk-informed VM programs described below, and
25 future described in Section 8.2.2, Vegetation Management and Inspections,
26 in PG&E's 2023–2025 WMP.

- 27 – Focused Tree Inspections: We developed specific areas of focus
28 (referred to as Areas of Concern), primarily in the HFRA, where we will
29 concentrate our efforts to inspect and address high-risk locations, such
30 as those that have experienced higher volumes of vegetation damage
31 during PSPS events, outages, and/or ignitions.
- 32 – VM for Operational Mitigations: This program is intended to help reduce
33 outages and potential ignitions using a risk informed, targeted plan to
34 mitigate potential vegetation contacts based on historic vegetation

1 caused outages on EPSS-enabled circuits. We will initially focus on
2 mitigating potential vegetation contacts in circuit protection zones that
3 have experienced vegetation caused outages. Scope of work will be
4 developed by using EPSS and historical outage data and vegetation
5 failure from the Wildfire Distribution Risk Model v3 risk model.
6 EPSS-enabled devices vegetation outages extent of condition
7 inspections may generate additional tree work.

- 8 – Tree Removal Inventory: This is a long-term program intended to
9 systematically work down trees that were previously identified through
10 EVM inspections. We will develop annual risk-ranked work plans and
11 mitigate the highest risk-ranked areas first and will continue monitor the
12 condition of these trees through our established inspection programs.

13 In 2026, PG&E continues to drive towards a more risk informed
14 approach, while adjusting its program based on external feedback to
15 minimize customer touchpoints. As a result, PG&E consolidated its
16 programs starting in 2026. PG&E's FTI program now is incorporated
17 into its normal Routine and Hazard program, with those elevated
18 inspections conducted at the same time. The VM for Operational
19 Mitigations is incorporated into normal operating procedures, by further
20 addressing vegetation contact based on historical outages beyond
21 EPSS enabled circuits, but also other weather driven events like PSPS.
22 Lastly, the TRI trees will also be incorporated into its normal Routine
23 and Hazard program to inspect and determine the appropriate action to
24 address these trees. PG&E's vegetation management activities are
25 further described in Section 9.2, Vegetation Management and
26 Inspections, in PG&E's 2026–2028 WMP.

- 27 • Maturation of the Continuous Monitoring Program: In 2025, PG&E
28 expanded deployment of our Continuous Monitoring (CM) Program by
29 increasing installation of Gridscope sensors, Early Fault Detection,
30 Distribution Fault Anticipation, line sensors, and SmartMeter machine
31 learning solutions. The CM Program has enabled identification of faults and
32 defects consistent with ignition failure modes before they fail and have the
33 potential to cause an ignition. These include, among other failure modes,
34 melted or degraded connectors and overloaded equipment. PG&E is

- 1 prioritizing installation of the CM technologies using wildfire risk buydown
- 2 curves, ignition, and failure history.
- 3 Please see Section 10.3.2 in PG&E's 2026-2028 WMP for additional details.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.15
NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS
(TRANSMISSION)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 3.15**
4 **NUMBER OF CPUC-REPORTABLE IGNITIONS IN HFTD AREAS**
5 **(TRANSMISSION)**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.15) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metrics (SOM) 3.15 – Number of California
11 Public Utilities Commission (CPUC)-Reportable Ignitions in High Fire Threat
12 District (HFTD) areas (Transmission) is defined as:

13 *Number of CPUC-reportable ignitions involving overhead transmission*
14 *circuits in HFTD Areas.*

15 *A CPUC-Reportable Ignition refers to a fire incident where the following*
16 *three criteria are met: (1) Ignition is associated with Pacific Gas and Electric*
17 *Company (PG&E or the Company) electrical assets, (2) something other*
18 *than PG&E facilities burned, and (3) the resulting fire travelled more than*
19 *one linear meter from the ignition point.¹*

20 For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

21 PG&E provides the CPUC with annual ignition data in the Fire Incident
22 Data Collection Plan, to the Office of Energy Infrastructure and Safety
23 quarterly via quarterly geographic information system, data reporting, in
24 quarterly Wildfire Mitigation Plan (WMP) updates, and the Safety
25 Performance Metrics Report.

26 **2. Introduction of Metric**

27 The number of CPUC-Reportable Ignitions in HFTDs provides one way
28 to gauge the level of wildfire risk that customers and communities are
29 exposed to from overhead transmission assets. PG&E's objective is to

1 Please CPUC Decision (D.) 14-02-015, issued February 5, 2014 for additional details.

1 minimize the number of CPUC-Reportable ignitions in the right locations
2 during the right conditions that may trigger a catastrophic wildfire.

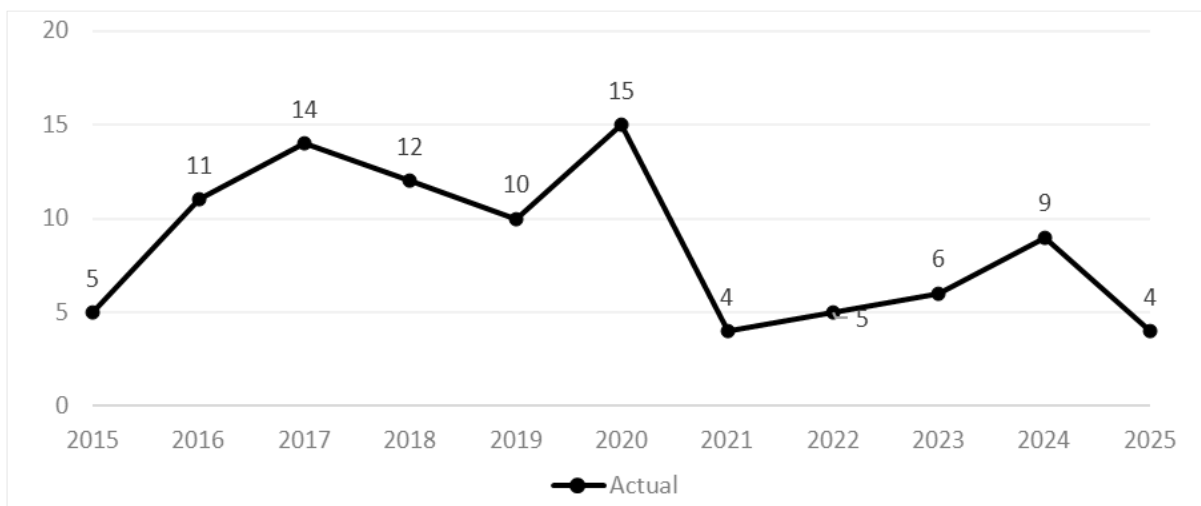
3 **B. (3.15) Metric Performance**

4 **1. Historical Data (2015 – 2025)**

5 PG&E implemented the Fire Incident Data Collection Plan, in response
6 to D.14-02-015, in June 2014 and our record, the Ignitions Tracker, includes
7 all CPUC-Reportable ignitions from June 2014 to present. The 2014 data
8 does not represent a complete year and is excluded in this analysis.

9 PG&E’s overhead transmission circuits traverse approximately
10 5,400 miles of terrain in the HFTD areas where the overhead conductor is
11 primarily bare wire, supported by structures consisting of poles and towers.
12 The annual number of CPUC-Reportable ignitions is too low to detect any
13 statistical pattern.

**FIGURE 3.15-1
HISTORICAL PERFORMANCE (2015 – 2025)**

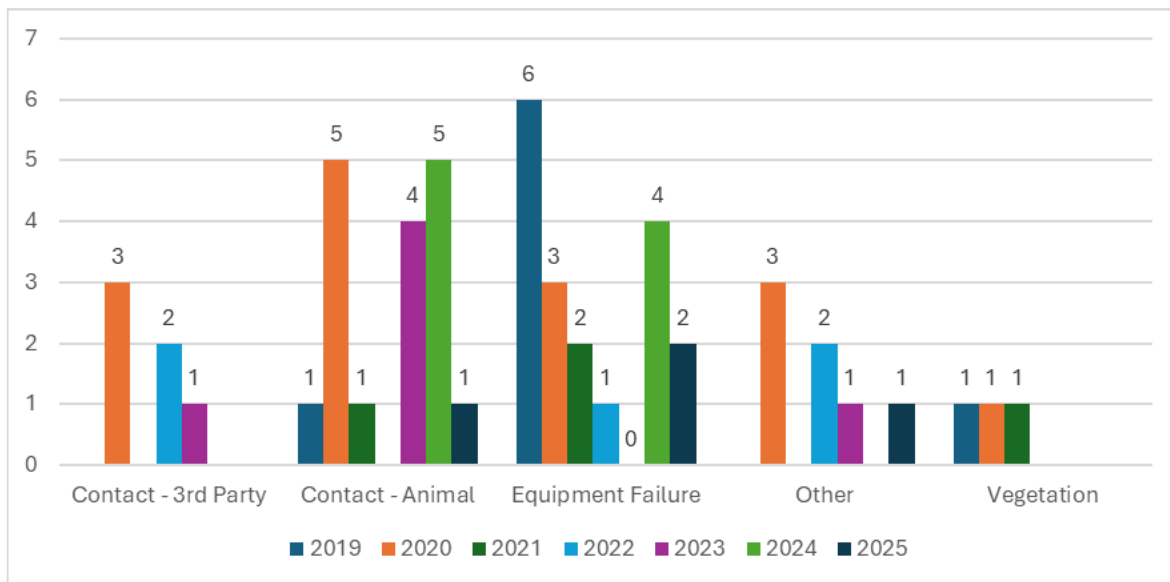


Note: As part of a Risk Assessment Improvement Plan item in PG&E’s 2023 – 2025 WMP, PG&E reviewed historic ignitions data and reattributed certain historical events, resulting in slight changes in the count of ignitions in scope for this metric for historical years (some years increased while others decreased). In general, ignition counts represent a snapshot in time and are subject to change based on new data.

14 The main causes of CPUC-Reportable ignitions have been collected
15 and classified. These fall into five broad categories: third-party contact,
16 animal contact, equipment failure, vegetation contact, and other causes.

1 The counts for 2019 through 2025 are shown in the graph below
 2 (Figure 3.15-2).

**FIGURE 3.15-2
 HISTORIC (2019 – 2025) PERFORMANCE BY SUSPECTED CAUSE**



3 **2. Data Collection Methodology**

4 Data will be collected per PG&E’s Fire Incident Data Collection Plan
 5 (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of
 6 unique HFTD CPUC-Reportable ignitions attributable to the transmission
 7 asset class with overhead construction types.

8 The following ignition events captured by PG&E’s Fire Incident Data
 9 Collection Plan (Utility Standard/Procedure RISK-6306S/P) will be excluded
 10 for this metric:

- 11 • Duplicate events;
- 12 • Ignitions that do not meet CPUC reporting criteria;
- 13 • Ignition events outside of Tier 2 and Tier 3 HFTD;
- 14 • Distribution Ignitions; and
- 15 • Ignitions attributable to underground or pad mounted assets as these
 16 are not overhead assets. Ignitions caused by non-overhead assets in
 17 HFTD are rare and, as the fires are often contained to the asset, pose
 18 less of a wildfire risk.

1 **3. Metric Performance for the Reporting Period**

2 Historically, reportable transmission ignitions in HFTD are low in volume
3 with variability year-to-year, which complicates the detection of significant
4 trends. PG&E observed four CPUC-reportable ignitions on overhead
5 transmission assets in 2025; the official cause of one ignition is unknown,
6 however PG&E suspects it to have been caused by bird guano on an
7 insulator (animal/avian cause), a second was caused by avian contact, and
8 two were caused by equipment failure.

9 **C. (3.15) 1-Year Target and 5-Year Target**

10 **1. Updates to 1- and 5-Year Targets Since Last Report**

11 PG&E proposes no changes to the 1 and 5-year targets for this period.
12 PG&E set the 2026 and 2030 upper limit of the target range to account for
13 the previous five years from 2020 to 2024 of actual results and variability
14 driven by weather, and external factors like seasonal bird migration.

15 **2. Target Methodology**

16 To establish the 1-Year and 5-Year targets, PG&E considered the
17 following factors:

- 18 • Historical Data and Trends: PG&E has layered significant wildfire
19 mitigation strategies over the past eight years and, outside of PG&E's
20 own ignition record, to help guide in target setting. PG&E is utilizing the
21 previous 5-year worth of ignition actuals (2020 – 2024) to set 2026 and
22 2030 target setting;
- 23 • Benchmarking: PG&E benchmarks extensively with other utilities in
24 terms of wildfire risk and ignition reduction. Specifically, PG&E reviews
25 utility ignition trends (where available) and analyzes the risk associated
26 large utility wildfires around the world;
- 27 • Regulatory Requirements: CPUC D.14-02-015;
- 28 • Appropriate/Sustainable Indicators for Enhanced Oversight and
29 Enforcement: The targets for this metric are suitable for Enhanced
30 Oversight and Enforcement as they consider the potential for an
31 increase in severe weather events due to climate change; and
- 32 • Other Qualitative Considerations: The target range takes consideration
33 for some variability in weather.

1 **3. 2026 Target**

2 PG&E's target for 2026 is 4-12. The upper and bottom ends of this
3 range represent the 5-year previous average from 2024 (8 ignitions)
4 subtracting/adding a full standard deviation (4 ignitions) for those same
5 years to account for variability.

6 **4. 2030 Target**

7 PG&E's target for 2030 is 4-12. The upper and bottom ends of this
8 range represent the 5-year previous average from 2024 (8 ignitions)
9 subtracting/adding a full standard deviation (4 ignitions) for those same
10 years to account for variability. The upper end of the range is 12 in 2026
11 and 2030 because the volume of transmission ignitions is low, while
12 variability year-to-year remains high.

13 **D. (3.15) Performance Against Target**

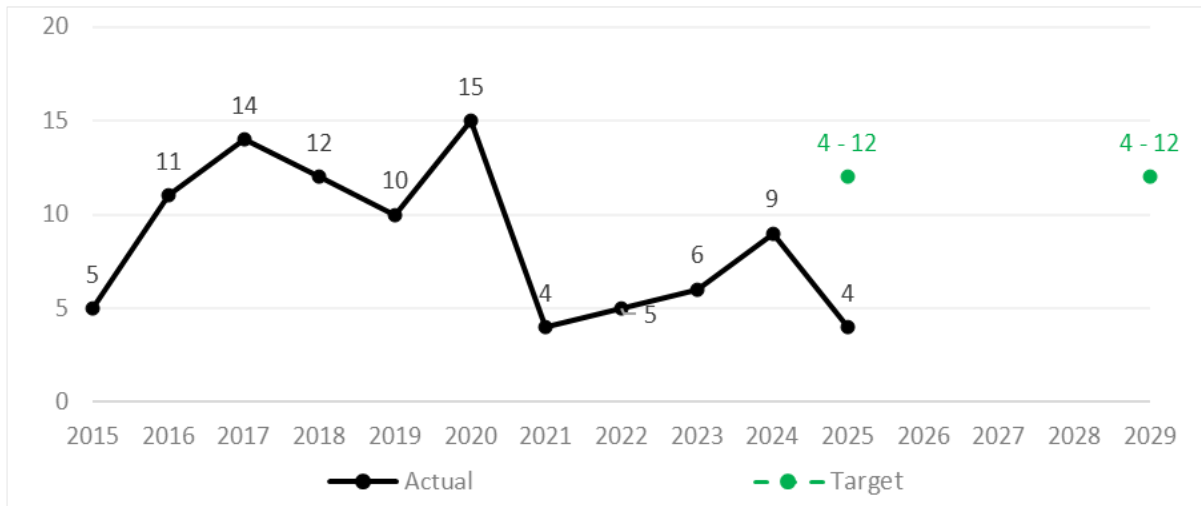
14 **1. Progress Towards the 1-Year Target**

15 As demonstrated in Figure 3.15-3 below, PG&E observed
16 four CPUC-reportable ignitions on overhead transmission assets in 2025,
17 within our target range of 4 – 12 ignitions.

18 **2. Progress Towards the 5-Year Target**

19 As discussed in Section E below, PG&E is continuing to deploy several
20 programs to keep metric performance within the Company's target range.
21 PG&E expects no deviation from delivering the 2030 goal for this metric.

**FIGURE 3.15-3
HISTORICAL PERFORMANCE (2015 – 2025) AND TARGETS (2025 AND 2029)**



Note: As part of a Risk Assessment Improvement Plan item in PG&E's 2023 – 2025 WMP, PG&E reviewed historic ignitions data and reattributed certain historical events, resulting in slight changes in the count of ignitions in scope for this metric for historical years (some years increased while others decreased). In general, ignition counts represent a snapshot in time and are subject to change based on new data.

E. (3.15) Current and Planned Work Activities

Through continual execution of its WMP, PG&E has taken action to reduce ignition risk associated with its transmission system, including:

- Utility Defensible Space Program/Proactive Support Structure Clearing: In 2023, PG&E expanded on Defensible Space Requirements in Public Resources Code Section 4292. Defensible Space is defined by three primary zones of clearance whereas in 2022 there were two zones. Starting in 2023 the first zone (0-5 feet (ft.)) from energized equipment or building is referred to as Zone 0 or the “Ember – Resistant Zone” and is intended to be void of any combustibles. The second zone (5-30 ft.) surrounding energized equipment and building is called the “Clean Zone” and in most cases (with minimal exceptions) is clear of trees and most vegetation. The third and final zone of clearance (30-100 ft.) is the “Reduced Fuel Zone” where vegetation is permitted if it is reduced or thinned and maintained regularly and within the requirements listed within PG&E’s hardening procedures.

 - Approximately 2,700 support structures were completed through this program in 2023 and 2024;

- 1 – PG&E completed clearing 645 support structures in 2025 through the
2 UDS program; and
- 3 – In addition to the 2025 UDS scope, PG&E executed support structure
4 clearing and utility defensible space projects associated with
5 approximately 4,000 high-risk support structures in HFTD/High Fire Risk
6 Area (HFRA). As 80 percent of PG&E’s transmission-caused ignitions in
7 HFTD and HFRA occur within 30 feet of the base of the structure (1), this
8 effort is critical in reducing significant wildfire risk in the locations where
9 wildfire risk and consequence are highest.

10 Please see Section 8.2.3.5, Substation Defensible Space (Mitigation) in
11 PG&E’s 2023-2025 WMP and Section 9.6, Defensible Space, in PG&E’s
12 2026-2028 WMP for additional details.

- 13 • Conductor Replacement and Removal: In 2021, PG&E completed
14 93.8 miles of conductor replacements and 10 miles of conductor removals.
15 All this work took place on lines traversing HFTD areas. In 2022, PG&E
16 removed or replaced 32 circuit miles of conductor in HFTD or HFRA. In
17 2023, PG&E removed or replaced 43 circuit miles of conductor in HFTD or
18 HFRA. [An additional 19 circuit miles were completed through 2025.](#)

19 Please see Section 8.1.2.5.1, Traditional Overhead Hardening –
20 Transmission Conductor in PG&E’s 2023-2025 WMP for additional details.

- 21 • Conductor Splice Shunts: A conductor splice is a potential point of failure
22 within a conductor span, due to factors such as corrosion, moisture
23 intrusion, vibration, and workmanship variability. To reduce the risk of
24 failure, PG&E had initiated a program to install a shunt splice on top of the
25 existing splices on This installation eliminates the splice as a single point of
26 failure, as a failure of the original splice would not result in down conductor.
27 Lines prioritized for this program are based on higher risk splice and wildfire
28 consequence. In 2023, 20 transmission lines had splice shunts installed. In
29 2024, 22 transmission lines had splice shunts installed. An additional
30 25 lines were completed in 2025.

31 Please see Section 8.1.2.5.1, Traditional Overhead Hardening –
32 Transmission Conductor in PG&E’s 2023-2025 WMP and Section 8.2.5.1,
33 Traditional Overhead Hardening – Transmission Conductor in PG&E’s
34 2026-2028 WMP for additional details.

1 • Conductor Segment Replacements: Another program has been initiated to
2 replace targeted conductor segments within a line. A transmission line may
3 consist of multiple conductor types, including spans of higher-risk segments
4 such as small-sized conductors. This program reduces risk for lines where
5 the conductor segments are may be at higher risk, but the supporting
6 structures are generally in good condition and there is no expected
7 additional electrical capacity need to increase the conductor size. PG&E
8 completed segment replacements on two lines in HFTD/HFRA in 2025 and
9 plans to complete four segment replacements in 2026.

10 Please see Section 8.1.2.5.1, Traditional Overhead Hardening –
11 Transmission Conductor in PG&E’s 2023-2025 WMP and Section 8.2.5.1,
12 Traditional Overhead Hardening – Transmission Conductor in PG&E’s
13 2026-2028 WMP for additional details.

14 • Proactive Animal Abatement: Given that avian-caused ignitions are the top
15 driver in recent years, PG&E is exploring two specific mitigations associated
16 with reducing risk of avian related ignitions:

- 17 – PG&E has designed dielectric covers to cover a portion of steel lattice
18 towers where we have observed faults caused by avian contact. PG&E
19 installed these devices at 18 towers in 2025 and is conducting a
20 feasibility study to inform future programs as part of a WMP initiative in
21 the 2026-2028 WMP. Please see Qualitative commitment GH-13
22 Section 8.2.12 and 8.2.12.2 Other Technologies and Systems not Listed
23 Above – Transmission in PG&E’s 2026 2028 WMP for additional details.
- 24 – Executing an annual program to remove bird nests after nesting season.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.16
PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN
HFTD AREAS

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 3.16
PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN
HFTD AREAS

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 3.16**
4 **PERCENTAGE OF CPUC-REPORTABLE IGNITIONS IN**
5 **HFTD AREAS**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (3.16) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metrics (SOM) 3.16 – percentage of California
11 Public Utilities Commission (CPUC)-Reportable Ignitions in High Fire Threat
12 District (HFTD) Areas (Transmission) is defined as:

13 *The number of CPUC-reportable ignitions involving overhead*
14 *transmission circuits in HFTD divided by circuit miles of overhead*
15 *transmission lines in HFTD multiplied by 1,000 miles (ignitions per*
16 *1,000 HFTD circuit mile).*

17 A CPUC-reportable ignition refers to a fire incident where the following
18 three criteria are met: (1) Ignition is associated with Pacific Gas and Electric
19 Company (PG&E) electrical assets, (2) something other than PG&E facilities
20 burned, and (3) the resulting fire travelled more than one linear meter from
21 the ignition point.¹

22 For this SOM, reporting is specific to Tier 2 and Tier 3 HFTDs.

23 PG&E provides the CPUC with annual ignition data in the Fire Incident
24 Data Collection Plan, to the Office of Energy Infrastructure and Safety
25 quarterly via quarterly GIS data reporting, in quarterly Wildfire Mitigation
26 Plan (WMP) updates, and the Safety Performance Metrics Report.

27 **2. Introduction of Metric**

28 The number of CPUC-reportable ignitions in HFTDs, normalized by
29 circuit mileage, provides one way to gauge the level of wildfire risk that
30 customers and communities are exposed to from overhead transmission

1 Please see CPUC Decision (D.) 14-02-015, issued February 5, 2014 for additional details.

1 assets. PG&E’s objective is to minimize the number of CPUC-reportable
2 ignitions in the right locations during the right conditions that may trigger a
3 catastrophic wildfire.

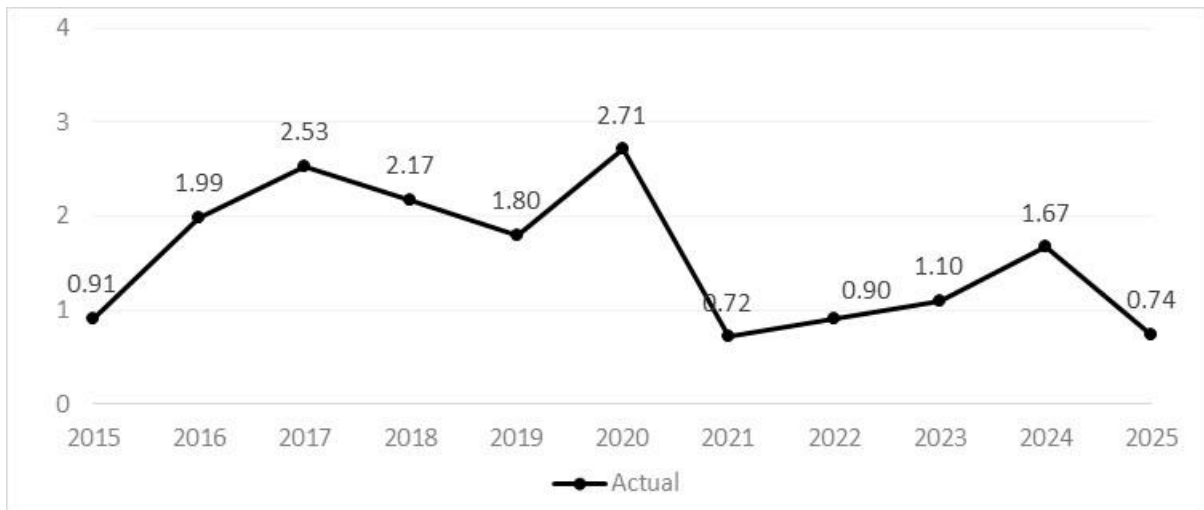
4 **B. (3.16) Metric Performance**

5 **1. Historical Data (2015 – 2025)**

6 PG&E implemented the Fire Incident Data Collection Plan, in response
7 to CPUC D.14-02-015, in June 2014 and our record, the Ignitions Tracker,
8 includes all CPUC-reportable ignitions from June 2014 to present. The 2014
9 data does not represent a complete year and is excluded in this analysis.

10 PG&E’s overhead transmission circuits traverse approximately
11 5,400 miles of terrain in the HFTD areas where the overhead conductor is
12 primarily bare wire, supported by structures consisting of poles and towers.
13 The annual number of CPUC-reportable ignitions is too low and too variable
14 to detect any statistical pattern.

**FIGURE 3.16-1
HISTORICAL PERFORMANCE
(2015 – 2025)**



Note: As part of a Risk Assessment Improvement Plan item in PG&E’s 2023-2025 WMP, PG&E reviewed historic ignitions data and reattributed certain historical events, resulting in slight changes in the count of ignitions in scope for this metric for historical years (some years increased while others decreased). In general, ignition counts represent a snapshot in time and are subject to change based on new data.

2. Data Collection Methodology

Data will be collected per PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P). Results will be inclusive of unique HFTD CPUC-reportable ignitions attributable to the transmission asset class with overhead construction types.

The following ignition events captured by PG&E's Fire Incident Data Collection Plan (Utility Standard/Procedure RISK-6306S/P) will be excluded for this metric:

- Duplicate events;
- Ignitions that do not meet CPUC reporting criteria;
- Ignition events outside of Tier 2 and Tier 3 HFTD;
- Distribution Ignitions; and
- Ignitions attributable to underground or pad mounted assets, as these are not overhead assets. Ignitions caused by non-overhead assets in HFTD are rare and, as the fires are often contained to the asset, pose less of a wildfire risk.

The circuit mileage utilized to calculate the 2015-2022 performance of this metric originates from PG&E's Electrical Asset Data Reports, refreshed December 2022. The 2023-2024 performance and targets are based on an updated sum of overhead circuit mileage, refreshed in 2023.

3. Metric Performance for the Reporting Period

Historically, reportable transmission ignitions in HFTD are low in volume with variability year-to-year, which complicates the detection of significant trends. PG&E observed four CPUC-reportable ignitions on overhead transmission assets in 2025; the official cause of one ignition is unknown, however PG&E suspects it to have been caused by bird guano on an insulator (animal/avian cause), a second was caused by avian contact, and two were caused by equipment failure.

C. (3.16) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

PG&E proposes no changes to the 1 and 5-year targets for this period. PG&E set the 2026 and 2030 upper limit of the target range to account for

1 the previous 5 years from 2020 to 2024 of actual results and variability
2 driven by weather, and external factors like seasonal bird migration.

3 **2. Target Methodology**

4 To establish the 1-Year and 5-Year targets, PG&E considered the
5 following factors:

- 6 • Historical Data and Trends: PG&E has layered significant wildfire
7 mitigation strategies over the past 8 years and, outside of PG&E's own
8 ignition record, to help guide in target setting. PG&E is utilizing the
9 previous 5-years worth of ignition actuals (2020-2024) to set 2026 and
10 2030 target setting;
- 11 • Benchmarking: PG&E benchmarks extensively with other utilities in
12 terms of wildfire risk and ignition reduction. Specifically, PG&E reviews
13 utility ignition trends (where available) and analyzes the risk associated
14 large utility wildfires around the world;
- 15 • Regulatory Requirements: CPUC D.14-02-015;
- 16 • Appropriate/Sustainable Indicators for Enhanced Oversight and
17 Enforcement: The targets for this metric are suitable for Enhanced
18 Oversight and Enforcement as they consider the potential for an increase
19 in severe weather events due to climate change; and
- 20 • Other Qualitative Considerations: The target range takes consideration
21 for some variability in weather.

22 **3. 2026 Target**

23 PG&E's target for 2026 is 4-12 (corresponding to a rate of 0.74 – 2.23
24 ignitions per 1,000 circuit miles). The upper and bottom ends of this range
25 represent the 5-year previous average from 2020-2024 (8 ignitions)
26 subtracting/adding a full standard deviation (4 ignitions) for those same
27 years to account for variability.

28 **4. 2029 Target**

29 PG&E's target for 2030 is 4-12 (corresponding to a rate of 0.74 – 2.23
30 ignitions per 1,000 circuit miles). The upper and bottom ends of this range
31 represent the 5-year previous average from 2020-2024 (8 ignitions)
32 subtracting/adding a full standard deviation (4 ignitions) for those same
33 years to account for variability. The upper end of the range stays at 12 in

1 2026 and 2030 because the volume of transmission ignitions is low, while
2 variability year to year remains high.

3 **D. (3.16) Performance Against Target**

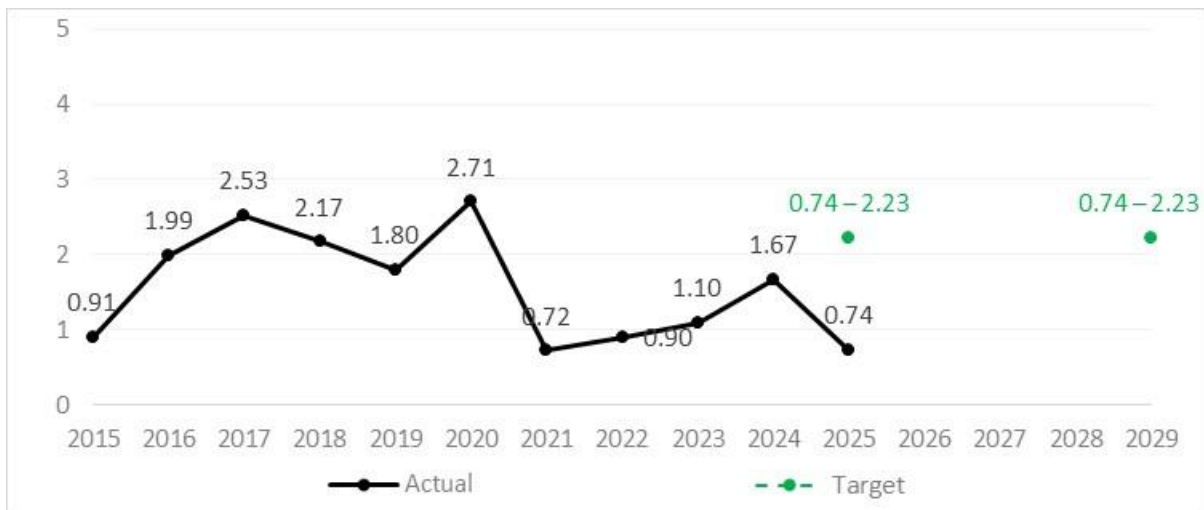
4 **1. Progress Towards the 1-Year Target**

5 As demonstrated in Figure 3.16-2 below, PG&E observed four
6 CPUC-reportable ignitions on overhead transmission assets in 2025
7 (corresponding to a rate of 0.74 ignitions per 1,000 circuit miles), within our
8 2025 target range of 4 – 12 ignitions (corresponding to a rate of 0.74 – 2.23
9 ignitions per 1,000 circuit miles).

10 **2. Progress Towards the 5-Year Target**

11 As discussed in Section E below, PG&E is continuing to deploy several
12 programs to keep metric performance within the Company’s target range.
13 PG&E expects no deviation from delivering the 2030 goal for this metric.

**FIGURE 3.16-2
HISTORICAL PERFORMANCE (2015 – 2025) AND
TARGETS (2025 AND 2029)**



Note: As part of a Risk Assessment Improvement Plan item in PG&E’s 2023-2025 WMP, PG&E reviewed historic ignitions data and reattributed certain historical events, resulting in slight changes in the count of ignitions in scope for this metric for historical years (some years increased while others decreased). In general, ignition counts represent a snapshot in time and are subject to change based on new data.

1 **E. (3.16) Current and Planned Work Activities**

2 Through continual execution of its WMP, PG&E has taken action to reduce
3 ignition risk associated with its transmission system, including:

- 4 • Utility Defensible Space Program/Proactive Support Structure Clearing: In
5 2023, PG&E expanded on Defensible Space Requirements in Public
6 Resources Code Section 4292. Defensible Space is defined by three
7 primary zones of clearance whereas in 2022 there were two zones. Starting
8 in 2023 the first zone (0-5 feet (ft.)) from energized equipment or building is
9 referred to as Zone 0 or the “Ember – Resistant Zone” and is intended to be
10 void of any combustibles. The second zone (5-30 ft.) surrounding energized
11 equipment and building is called the “Clean Zone” and in most cases (with
12 minimal exceptions) is clear of trees and most vegetation. The third and final
13 zone of clearance (30-100 ft.) is the “Reduced Fuel Zone” where vegetation
14 is permitted if it is reduced or thinned and maintained regularly and within the
15 requirements listed within PG&E’s hardening procedures.

- 16 – Approximately 2,700 support structures were completed through this
17 program in 2023 and 2024;
- 18 – [PG&E completed clearing 645 support structures in 2025 through the](#)
19 [Utility Defensible Space program; and](#)
- 20 – In addition to the 2025 UDS scope, PG&E executed support structure
21 clearing and utility defensible space projects associated with
22 approximately 4,000 high-risk support structures in HFTD/High Fire Risk
23 Area (HFRA). As 80 percent of PG&E’s transmission-caused ignitions in
24 HFTD and HFRA occur within 30 feet of the base of the structure (1), this
25 effort is critical in reducing significant wildfire risk in the locations where
26 wildfire risk and consequence are highest.

27 Please see Section 8.2.3.5, Substation Defensible Space (Mitigation) in
28 PG&E’s 2023-2025 WMP and Section 9.6, Defensible Space, in PG&E’s
29 2026-2028 WMP for additional details.

- 30 • Conductor Replacement and Removal: In 2021, PG&E completed 93.8 miles
31 of conductor replacements and 10 miles of conductor removals. All this work
32 took place on lines traversing HFTD areas. In 2022, PG&E removed or
33 replaced 32 circuit miles of conductor in HFTD or HFRA. In 2023, PG&E

1 removed or replaced 43 circuit miles of conductor in HFTD or HFRA. [An](#)
2 [additional 19 circuit miles were completed through 2025.](#)

3 Please see Section 8.1.2.5.1, Traditional Overhead Hardening –

4 Transmission Conductor in PG&E’s 2023-2025 WMP for additional details.

- 5 • Conductor Splice Shunts: A conductor splice is a potential point of failure
6 within a conductor span, due to factors such as corrosion, moisture intrusion,
7 vibration, and workmanship variability. To reduce the risk of failure, PG&E
8 had initiated a program to install a shunt splice on top of the existing splices
9 on This installation eliminates the splice as a single point of failure, as a
10 failure of the original splice would not result in down conductor. Lines
11 prioritized for this program are based on higher risk splice and wildfire
12 consequence. In 2023, 20 transmission lines had splice shunts installed. In
13 2024, 22 transmission lines had splice shunts installed. An additional
14 25 lines were completed in 2025.

15 Please see Section 8.1.2.5.1, Traditional Overhead Hardening –

16 Transmission Conductor in PG&E’s 2023-2025 WMP and Section 8.2.5.1,

17 Traditional Overhead Hardening – Transmission Conductor in PG&E’s

18 2026-2028 WMP for additional details.

- 19 • Conductor Segment Replacements: Another program has been initiated to
20 replace targeted conductor segments within a line. A transmission line may
21 consist of multiple conductor types, including spans of higher-risk segments
22 such as small-sized conductors. This program reduces risk for lines where
23 the conductor segments are may be at higher risk, but the supporting
24 structures are generally in good condition and there is no expected additional
25 electrical capacity need to increase the conductor size. PG&E completed
26 segment replacements on two lines in HFTD/HFRA in 2025 and plans to
27 complete four segment replacements in 2026.

28 Please see Section 8.1.2.5.1, Traditional Overhead Hardening –

29 Transmission Conductor in PG&E’s 2023-2025 WMP and Section 8.2.5.1,

30 Traditional Overhead Hardening – Transmission Conductor in PG&E’s

31 2026-2028 WMP for additional details.

- 32 • Proactive Animal Abatement: Given that avian-caused ignitions are the top
33 driver in recent years, PG&E is exploring two specific mitigations associated
34 with reducing risk of avian related ignitions:

- 1 – PG&E has designed dielectric covers to cover a portion of steel lattice
2 towers where we have observed faults caused by avian contact. PG&E
3 installed these devices at 18 towers in 2025 and is conducting a
4 feasibility study to inform future programs as part of a WMP initiative in
5 the 2026-2028 WMP. Please see Qualitative commitment GH-13
6 Section 8.2.12 and 8.2.12.2 Other Technologies and Systems not Listed
7 Above – Transmission in PG&E’s 2026 2028 WMP for additional details.

**PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:**

CHAPTER 4.1

**NUMBER OF GAS DIG-INS PER 1,000 UNDERGROUND
SERVICE ALERT (USA) TICKETS ON
TRANSMISSION AND DISTRIBUTION PIPELINES**

PACIFIC GAS AND ELECTRIC COMPANY
 SAFETY AND OPERATIONAL METRICS REPORT:
 CHAPTER 4.1
 NUMBER OF GAS DIG-INS PER 1,000 UNDERGROUND
 SERVICE ALERT (USA) TICKETS ON
 TRANSMISSION AND DISTRIBUTION PIPELINES

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
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4 **NUMBER OF GAS DIG-INS PER 1,000 UNDERGROUND**
5 **SERVICE ALERT (USA) TICKETS ON**
6 **TRANSMISSION AND DISTRIBUTION PIPELINES**

7 The material updates to this chapter since the September 30, 2025 report are
8 identified in blue font.

9 **A. (4.1) Overview**

10 **1. Metric Definition**

11 Safety and Operational Metric 4.1 – Number of Gas Dig-Ins per
12 1,000 tickets on Transmission and Distribution Pipelines is defined as:

13 *The number of gas dig ins per 1,000 Underground Service Alert (USA)*
14 *tickets received for gas. A gas dig-in refers to damage (impact or exposure)*
15 *which occurs during excavation activities and results in a repair or*
16 *replacement of an underground gas facility¹. Excludes fiber and electric*
17 *tickets. Also excludes tickets originated by the Utility itself or by utility*
18 *contractors.²*

19 **2. Introduction of Metric**

20 Reducing gas dig-ins increases public safety and improves reliability. It
21 is therefore important to take reasonable steps to reduce this risk because
22 gas dig-ins represent a potential risk to people, property, and the
23 environment.

24 If ignited, gas from a dig-in could produce a fire or explosion, either of
25 which could result property damage, injury or even death. Release of gas
26 from a dig-in also produces a possible health hazard from inhalation of
27 natural gas. Finally, dig-ins typically produce a disruption or loss of service
28 to one or more customers.

1 Repair or replacement is warranted when the facility is weakened or partially or completely destroyed, including but not limited to damage to the protective coating, lateral support, cathodic protection, or the housing for the line device or facility.

2 The metric includes 3rd party tickets only.

For all these reasons, fewer dig-ins reduces risk to public safety and minimizes interruption to the gas business and customers.

B. (4.1) Metric Performance

1. Historical Data (2018 – 2025)

For this metric, Pacific Gas and Electric Company (PG&E or the Company or the Utility) has eight years of historic data available, which includes 2018- 2025. The past eight years were used for analysis in target setting. Over the historical reporting period, performance improved as demonstrated by both an overall upward trend in USA tickets and a downward trend in gas dig-ins.

**FIGURE 4.1-1
THIRD-PARTY TICKETS AND TOTAL DIG-IN COUNTS
2018 – 2025**

3rd Party Ticket Counts									Dig-In Count								
Month	2018	2019	2020	2021	2022	2023	2024	2025	Month	2018	2019	2020	2021	2022	2023	2024	2025
January	66,605	66,900	74,736	69,544	83,536	60,314	76,150	85,610	January	100	89	93	118	118	79	77	77
February	62,387	58,586	70,016	74,323	80,127	61,733	72,219	76,831	February	131	78	119	116	106	79	65	58
March	66,538	74,563	69,991	95,177	93,432	68,744	78,603	83,710	March	103	103	98	126	143	66	82	69
April	71,514	85,215	67,071	93,335	83,657	73,186	86,984	93,180	April	147	140	117	147	120	111	110	95
May	75,794	86,339	71,786	87,432	87,005	83,866	86,518	90,578	May	209	140	128	139	150	123	114	128
June	69,824	81,989	80,614	93,008	88,319	80,983	78,908	86,917	June	176	176	170	183	149	121	114	122
July	68,927	92,787	80,926	84,316	81,346	75,831	87,875	92,657	July	190	196	201	170	145	110	141	155
August	74,158	89,869	76,521	87,507	94,628	85,879	89,998	88,943	August	186	200	182	175	156	135	152	134
September	64,678	84,840	79,684	84,126	86,949	79,082	84,797	92,359	September	173	167	178	163	124	139	138	134
October	77,779	91,022	81,680	82,106	87,461	84,875	93,954	95,517	October	179	191	155	135	131	117	129	130
November	64,861	72,476	72,089	82,859	79,547	76,765	73,354	75,512	November	139	149	131	101	96	119	91	61
December	56,219	64,452	73,995	71,744	62,951	63,816	76,550	83,917	December	110	87	126	64	45	73	68	72
Total	819,284	949,038	899,109	1,005,477	1,008,958	895,074	985,910	1,045,731	Total	1,843	1,716	1,698	1,637	1,483	1,272	1,281	1,235

2. Data Collection Methodology

The data used for this metric reporting is maintained in two files. Together, these databases identify the number of dig-ins and the 811 tickets, respectively. To ensure accuracy of the Master Dig-In File data, three data sources are reviewed:

- 1) The repair data file recorded in SAP – (Obtained using Business Objects GCM058 Quarterly GQI Extract Report);
- 2) The Event Management (EM) Tool obtained from Gas Dispatch, data file; and
- 3) The Dig-In Reduction Teams (DiRT) Pronto download file, obtained from the DiRT team data download report.

Events that meet the definition of dig-in are recorded as a ratio of total dig-ins (count) divided by the third-party USA tickets (count) multiplied

1 by 1,000. This metric does not include tickets originated by the Utility itself
2 or by utility contractors.

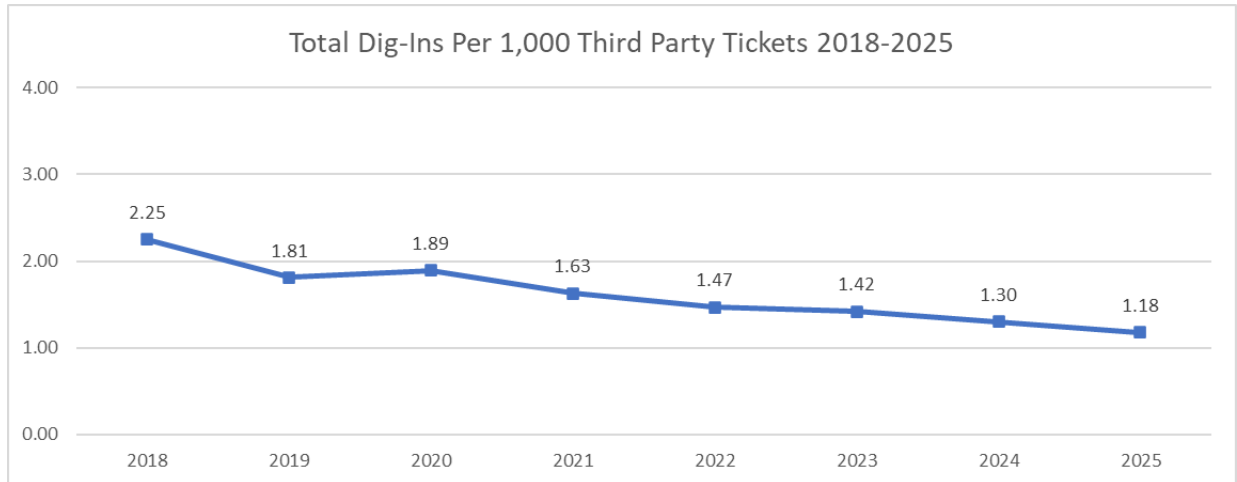
3 This metric does not include PG&E dig-ins to third party underground
4 infrastructure (e.g., sewer, water, telco). Dig-ins are reported in real time, so
5 they should be captured for the SOM reporting period. However, in the
6 event dig-ins are reported after the reporting cycle is closed, the dig-in would
7 be captured in the next reporting cycle (i.e. the next quarter of the current
8 year or the first quarter of the next year).

- 9 • Fiber and electric dig-ins are also excluded from the dig-in count.
- 10 • Also excluded from the dig-in count are the following:
- 11 • Damage to abandoned facilities.
- 12 • Damage due to materials failure (e.g., Aldyl-A pipe).
- 13 • Damage caused by trench collapse, soldering, or other non-excavation
14 activities—including situations where the facility is already fully exposed
15 and the damage does not meet the CGC 4216(g) definition of
16 excavation (e.g., cutting tree roots, incidental contact with an exposed
17 gas line).
- 18 • Damage deemed unavoidable (e.g., tree root embedded gas line)
- 19 • Damages to above-ground infrastructure, such as meters and risers, or
20 overbuilds.
- 21 • Pre-existing damage (e.g., due to corrosion or old wrap).
- 22 • Any intentional damage to a pipeline (e.g., drilling or cutting).
- 23 • Damage resulting from heavy vehicles driving over a covered facility,
24 which is not considered excavation activity.

25 **3. Metric Performance for the Reporting Period**

26 There has been an overall downward trend in the number of dig-ins per
27 1,000 third-party USA tickets. PG&E attributes the reduction to current and
28 planned Damage Prevention activities. Overall, PG&E has worked to
29 increase knowledge of the requirement to call 811 before digging through
30 Public Awareness Campaigns and by providing training and education to
31 contractors. PG&E continues to show an improvement in its dig-in ratio.

**FIGURE 4.1-2
TOTAL DIG-INS PER 1,000 THIRD-PARTY TICKETS
2018 – 2025**



1 **C. (4.1) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 Updated targets are provided below.

4 **2. Target Methodology**

5 To establish the 1-year and 5-year targets, PG&E considered the
6 following factors:

- 7 • Historical Data and Trends: Comparable data is available starting in
8 2018. Performance has been consistent with a downward trend from
9 2018-2025;
- 10 • Benchmarking: Although this metric is not benchmarkable as defined
11 (benchmarkable metrics include total tickets rather than only a subset of
12 tickets), benchmark data was used and derived as proxy guideposts to
13 understand PG&E performance for third-party tickets to inform target
14 setting. The target is set at a level consistent with strong performance;
- 15 • Regulatory Requirements: No regulatory requirements that pertain to
16 setting Target Methodology;
- 17 • Attainable Within Known Resources/Work Plan: Yes;
- 18 • Appropriate/Sustainable Indicators for Enhanced Oversight
19 Enforcement: Yes, performance at or below the set target is a
20 sustainable assumption for maintaining metric performance, plus room
21 for non-significant variability; and

- Other Qualitative Considerations: None.

3. 2026 Target

The 2026 target is to maintain metric performance at or better than a rate of 1.80 based on the factors described above. This improvement is based upon the Damage Prevention Organization's Dig-in Reduction Program. This target represents an appropriate indicator light to signal a review of potential performance issues. Target should not be interpreted as intention to worsen performance.

4. 2030 Target

The 2030 target is to maintain performance better than a rate of 1.80 based on the factors described above. Annual targets should continue to be informed by available benchmarking data.

D. (4.1) Performance Against Target

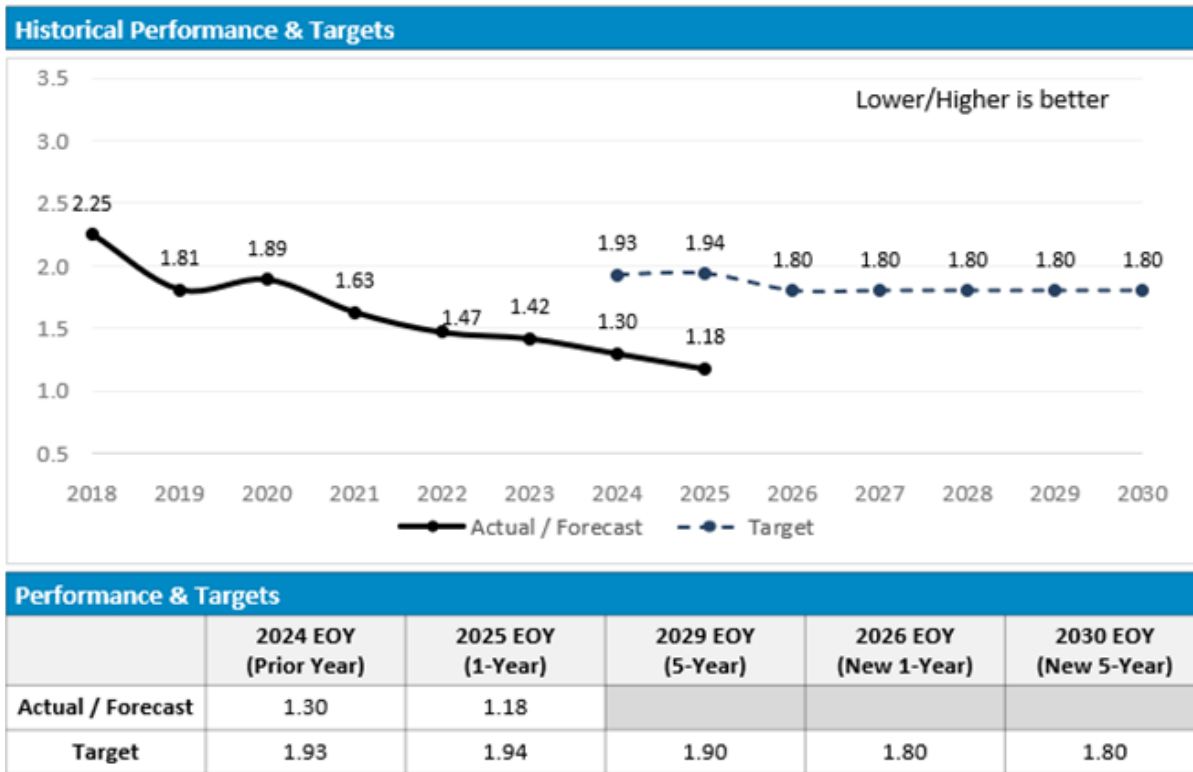
1. Maintaining Performance Against the 1-Year Target

As demonstrated in Figure 4.1-3, PG&E saw a 1.18 Gas Dig-In rate in 2025 which is better than the Company's 1-year target of 1.94 and remains consistent with the Company's objective of maintaining first quartile performance.

2. Maintaining Performance Against the 5-Year Target

As discussed in Section E, PG&E continues to use the Damage Prevention and DiRT programs to maintain performance in its efforts toward the Company's 5-year target.

**FIGURE 4.1-3
TOTAL DIG-INS PER 1,000 THIRD-PARTY TICKETS
2018 – 2025 AND
TARGETS 2024 THROUGH 2030**



E. (4.1) Current and Planned Work Activities

PG&E’s Damage Prevention team is responsible for the overall management of PG&E’s Damage Prevention Program, by managing the risks associated with excavations around PG&E’s facilities and conducting investigations. As an additional control to manage the Damage Prevention Program, PG&E has its DiRT. DiRT consists of 24 people (2 Supervisors, 15 PG&E Employees and 7 Contractors) deployed systemwide to investigate dig-ins. Team members work closely with various local PG&E operations personnel and respond to referrals from those employees when they observe excavations potentially not in compliance with the requirements of California Government Code Section 4216. DiRT personnel also assist the Ground Patrol team when they respond to immediate threats identified in the air by the Aerial Patrol team and other PG&E groups, in order to intervene in unsafe digging activities by third parties and follow-up to educate excavators as necessary.

1 PG&E's Damage Prevention activities include educational outreach activities
2 for professional excavators, local public officials, emergency responders, and
3 the general public who live and work within PG&E's service territory. The
4 program communicates safe excavation practices, required actions prior to
5 excavating near underground pipelines, availability of pipeline location
6 information, and other gas safety information through a variety of methods
7 throughout the year. These efforts are aimed at increasing public awareness
8 about the importance of utilizing the 811 Program before an excavation project is
9 started, understanding the markings that have been placed, and following safe
10 excavation practices after subsurface installations have been marked. Specific
11 activities aimed at preventing dig-ins include:

- 12 • Updated the Locate and Mark Field Guide and procedures to provide clear
13 instruction around critical processes for locating underground assets,
14 including troubleshooting of difficult to locate facilities;
- 15 • PG&E participates in the Common Ground Alliance (CGA) – Damage
16 Prevention Institute (DPI). PG&E began this program that is now run by a
17 third-party and available to utilities and excavators across the nation. The
18 program sets safety criteria that PG&E contractors are required to meet to
19 be eligible to do work on behalf of the Utility. The CGA is an
20 internationally-recognized program, with companies in Canada adopting and
21 implementing its certification requirements. The DPI is a way that PG&E is
22 making its own communities safer, and bringing best safety practices to the
23 industry;
- 24 • An 811 Ambassador program, which utilizes all PG&E employees to
25 properly identify unsafe excavation activities where employees learn how to
26 identify excavation-related delineations and utility operator markings; and
- 27 • In 2023 PG&E re-vamped its Locate and Mark training program to ensure
28 that our locators are receiving the best training available. This training
29 consists of multiple classroom-based modules as well as on the job training
30 with trained peer coaches.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.2
NUMBER OF OVERPRESSURE EVENTS

PACIFIC GAS AND ELECTRIC COMPANY
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NUMBER OF OVERPRESSURE EVENTS

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2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 4.2**
4 **NUMBER OF OVERPRESSURE EVENTS**

5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (4.2) Overview**

8 **1. Metric Definition**

9 Safety and Operational Metric 4.2 – Number of Overpressure (OP)
10 events is defined as:

11 *OP events as reportable under General Order (GO) 112-F 122.2(d)(5).*

12 **2. Introduction of Metric**

13 An OP event occurs when the gas pressure exceeds the Maximum
14 Allowable Operating Pressure (MAOP) of the pipeline, plus the build ups, set
15 forth in the Code of Federal Regulations (CFR) – 49 CFR 192.201.

16 This metric tracks the occurrence of OP events, which includes:

- 17 1) High pressure Gas Distribution:
- 18 a) (MAOP 1 pound per square inch gauge (psig) to 12 psig) greater
19 than 50 percent above MAOP;
- 20 b) (MAOP 12 psig to 60 psig) greater than 6 psig above MAOP; and
- 21 2) Gas Transmission (GT) pipelines greater than 10 percent above MAOP
22 (or the pressure produces a hoop stress of ≥ 75 percent Specified
23 Minimum Yield Strength, whichever is lower).

24 OP events on low pressure systems are excluded from this metric
25 because they are not defined in federal code 49 CFR 192.201.

26 OP events have the potential to overstress pipelines which pose
27 significant safety and operational risks to Pacific Gas and Electric
28 Company's (PG&E) gas system. PG&E has implemented multiple controls
29 and mitigations to reduce OP events.

30 Following the San Bruno event in 2010, an Overpressure Elimination
31 (OPE) task force was established to identify the root causes of OP events
32 and develop corrective actions.

1 In 2011, several decisions were made in response to San Bruno
2 incident. One of the most important corrective actions was to lower the
3 normal operating pressure below the MAOP across the system, which
4 resulted in a significant drop-off of OP events from 2011-2012.

5 Beginning in 2013, causal evaluations were conducted on all OP events.
6 Corrective actions from these evaluations included: equipment and design
7 review, training, fatigue management, improved Gas Event Reporting, and
8 improved work procedures.

9 In 2015, several benchmarking studies and industry evaluations were
10 conducted to learn OP elimination best practice. The benchmarking studies
11 and analyses helped influence the development and strategies of the OPE
12 Program.

13 In 2017, after the Folsom OP event,¹ the OPE Program was stood up
14 under one sponsor with dedicated resources. The OPE Program formalized
15 a two-pronged strategy to mitigate the risk of large OP events, while
16 reducing operational risk: (1) Human Performance Strategy, and
17 (2) Equipment-Related Strategy.

18 In 2020, PG&E retooled an effort to reduce the number of Human
19 Performance-related events. PG&E contracted with Exponent to perform an
20 analysis on the OP and near hit events using the Human Factors Analysis
21 and Classification System to drive focused actions to improve. This effort
22 helped the team to develop the Human Performance tools to: identify and
23 control risk, improve efficiency, avoid delays, reduce errors, prevent events,
24 and promote excellent performance at every facility.

¹ On January 24, 2017, the Hydraulically Independent System that delivers gas to the Folsom area experienced a large OP event in excess of the system's 60 psig MAOP. The OP event caused damage to the regulator station equipment and resulted in a significant number of leaks on plastic distribution piping. Inspection of the station revealed that the station filter had been clogged with debris and the regulator boot had been eroded by contaminants. Further investigation revealed that an upstream pigging project scraped corrosion scales from internal pipe walls. The scale—along with other debris—traveled downstream, until eventually collecting at Folsom, causing the OP event.

1 **B. (4.2) Metric Performance**

2 **1. Historical Data (2011 – 2025)**

3 Historical data of OP events are available since 2011. Various data
4 points of each OP event including location, Corrective Action Program
5 (CAP) number, date, cause, corrective action, etc. are documented in the
6 OP master list file attachment.

7 Data source of the metric is commonly from the Supervisory Control and
8 Data Acquisition (SCADA) system, and from direct accounts, including
9 gauge pressure readings, chart recorders, electronic recorders, and
10 metering data.

11 The availability of data has expanded throughout the years due to the
12 increase in pressure monitoring devices allowing more OP events to be
13 identified and recorded. In 2012, PG&E had 1,409 SCADA pressure points
14 on its pipeline system, and by end of December 2023, that number had
15 grown to 7,042. As of the end of 2024, there were 7,321 SCADA pressure
16 points throughout the PG&E system, [and as of the end of 2025, there are](#)
17 [now 7,529 SCADA pressure points.](#)

18 **2. Data Collection Methodology**

19 PG&E has both an automated process and field process for logging Gas
20 OP events. For the automated process, the SCADA system monitors
21 equipment pressure and notifies potential issues to Gas Control through
22 alarms. For the field process, field personnel are required to gauge
23 pressure during maintenance and clearances and report to Gas Control if an
24 abnormal operating condition arises. The Gas OP metric reporting process
25 flow is as follows:

- 26 1) Control Room Alarm/Third-Party Notification of abnormal pressure
27 reading or Gas Pipeline Operations and Maintenance (GPOM) finds
28 abnormal pressure reading during maintenance;
29 2) GPOM performs on-site investigation (validates pressure reading and
30 compares onsite pressure with SCADA pressure upon arrival).
31 “As-found” and “as-left” pressures are recorded on maintenance form;

- 1 3) Gas Control Room creates Abnormal Incident Report and issues
2 e-page. Facility Integrity Management Program reviews the e-page,
3 creates a CAP, and prepares a Quick Hit; and
- 4 4) OP event is recorded on OP Master List, and Apparent Cause
5 Evaluation is conducted to determine root cause and any corrective
6 actions as applicable.

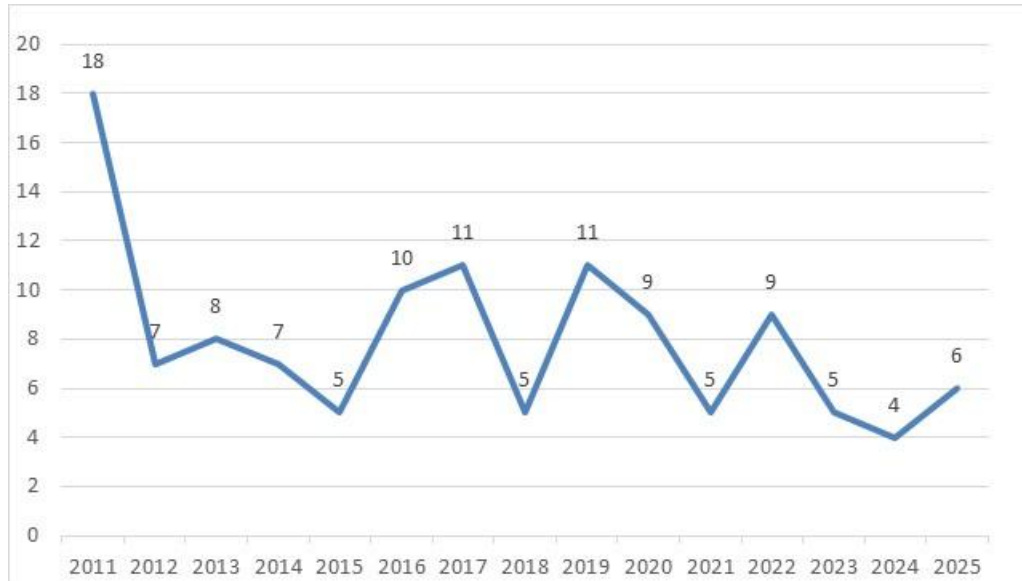
7 Several controls are in place for this metric:

- 8 1) Each OP event is entered into our system of record SAP system CAP to
9 ensure retention of record history;
- 10 2) Each OP event's datasets (location, CAP number, date, cause,
11 corrective action etc.) are reviewed by Facility Integrity Management
12 Program team to ensure accuracy and are logged in the OP Master List
13 which is viewable by all PG&E employees; and
- 14 3) Each OP event is distributed to stakeholders by an electronic page
15 (e-page) and an e-mail (Quick Hit), reviewed on the next Daily
16 Operations Briefing with leadership.

17 **3. Metric Performance for the Reporting Period**

18 PG&E experienced 6 OP events during 2025. Although this number is
19 larger than the total OP events that occurred in 2024 (which was the lowest
20 OP events recorded since PG&E begin tracking this metric in 2011), this
21 number is less than the target of 10 events that would indicate poor
22 performance in 2025. None of these 6 events resulted in a loss of
23 containment.

**FIGURE 4.2-1
OP EVENTS 2011 – 2025**



1 **C. (4.2) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 **None.** The 2026 target is set to be 9 (i.e., one less than 2025 target);
4 the 2030 target is set to be 8 (i.e., same as 2029 target).

5 **2. Target Methodology**

6 To establish the 1-year and 5-year targets, PG&E considered the
7 following factors:

- 8 • **Historical Data and Trends:** OP events have ranged from 4 to 11 events
9 per year since 2012. We exclude data from 2011, because it was the
10 first year OP data was collected and several anomalies were embedded
11 in the data and is shown for reference purposes only. The upper limit
12 for target-setting is based on the maximum number of events in the past
13 thirteen years;
- 14 • **Benchmarking:** This metric is not traditionally benchmarkable; however,
15 PG&E has contracted with third parties to conduct international and
16 North American industry evaluations. The benchmarking studies
17 indicated that PG&E has demonstrated strong performance in this area;
- 18 • **Regulatory Requirements:** OP events as reportable under California
19 Public Utilities Commission GO No.112-F, 122.2(d)(5);

- 1 • Attainable Within Known Resources/Workplan: Yes;
- 2 • Appropriate/Sustainable Indicators for Enhanced Oversight and
- 3 Enforcement: Yes, performance at or below the maximum of the past
- 4 thirteen years is a sustainable assumption for maintaining metric
- 5 performance, plus room for non-significant variability; and
- 6 • Other Qualitative Considerations: The approach of using the maximum
- 7 of the past thirteen years includes the consideration of the expected
- 8 impact of ongoing SCADA device installations—improved system
- 9 visibility and monitoring points may result in a higher number of
- 10 observed OP events. Additionally, as the OP Program has expanded,
- 11 there has been an increase in pressure monitoring devices throughout
- 12 the system, which allows more OP events to be identified and recorded.

13 3. 2026 Target

14 The upper limit for the 2026 target is based on the maximum of the past
15 fourteen years historical performance. The target is based on the highest
16 number annual events, within 95 percent confidence level (within
17 two standard deviations) of the average number of events, and reflects a
18 trend of continuous improvement. This target represents an appropriate
19 indicator light to signal a review of potential performance issues. Target
20 should not be interpreted as intention to worsen performance.

21 4. 2030 Target

22 The 2030 target reflects a 5-year outlook target demonstrating continued
23 focus on improvement year-over-year. PG&E continues to review
24 operations and look for opportunities to perform work to further reduce OP
25 events and contribute to system safety. However, it should be noted that in
26 Decision (D.) 21-11-069 the Commission denied or reduced funding for a
27 number of the OPE mitigation programs in the 2023 General Rate Case final
28 decision, especially in the Gas Distribution area.² It is unknown what impact
29 this will have on the future trend of OP events, but not adopting these

2 The GT and Gas Distribution Station OPP Enhancement Programs were not adopted by the commission (D.23-11-069 November 16, 2023, pp. 135-139). Similarly, Gas Distribution SCADA RTU installations were not adopted (D.23-11-069 November 16, 2023, pp. 211-214). All three of these programs are risk mitigations for large OP events.

1 programs is expected to decrease the pace of PG&E's mitigation efforts to
2 reduce OP events in the future. Therefore, despite not receiving
3 authorization from the rate case, PG&E continues to fund the OP elimination
4 efforts - although at a reduced pace.

5 **D. (4.2) Performance Against Target**

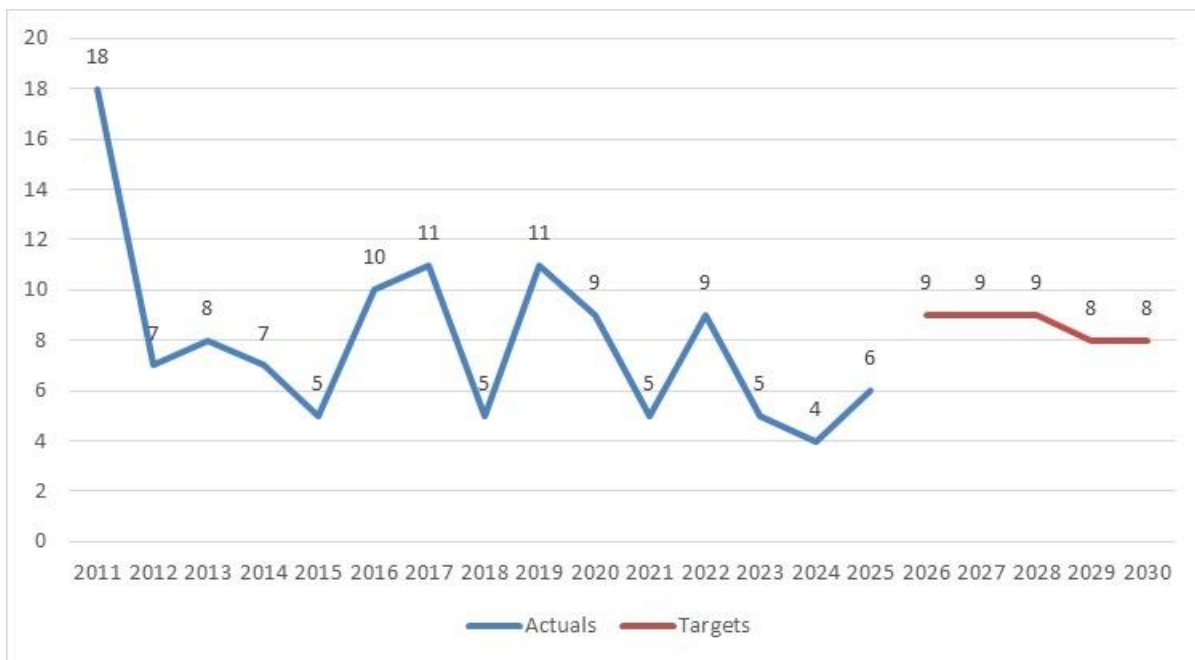
6 **1. Progress Towards the 1-Year Target**

7 In 2025, six OP events occurred in PG&E's gas system, which is less
8 than the Company's 1-year target of equal to or less than 10.

9 **2. Progress Towards the 5-Year Target**

10 As discussed in Section E below, PG&E is deploying several programs
11 to maintain or improve the long-term performance of the Over Pressure
12 metric to meet the Company's 5-year performance target.

FIGURE 4.2-2
OP EVENTS 2011 – 2025 AND TARGETS 2026 THROUGH 2030



13 **E. (4.2) Current and Planned Work Activities**

14 PG&E's initial objective included plans to execute the secondary
15 Overpressure Protection Program (OPP) to mitigate common failure mode
16 failure OP events for both GT and Gas Distribution over a 10-year period

1 (2018-2027). As noted, funding for the following mitigation programs was
2 eliminated in the 2023 GRC decision:

- 3 • Gas Distribution: Since the inception of the common failure mode mitigation
4 program through the end of 2025, PG&E has retrofitted approximately
5 1,058 Gas Distribution pilot-operated stations. By end of 2023, PG&E
6 exceeded the goal of retrofitting 50 percent of Gas Distribution
7 pilot-operated stations. PG&E will continue the retrofitting of Gas
8 Distribution pilot-operation stations to mitigate the common failure mode OP
9 events in the Gas Distribution System. These retrofits will be executed at a
10 considerably reduced pace in comparison to what was proposed in the GRC
11 (see fn. 2 on p. 4.2-6).
- 12 • Gas Transmission: In 2019, PG&E started rebuilding and retrofitting Large
13 Volume Customer Regulators (LVCR) sets specifically to address OP risks
14 and started rebuilding and/or retrofitting Large Volume Customer Meter
15 (LVCM) sets in 2023. [Since the inception of the common failure mode
16 mitigation program through the end of 2025, PG&E has rebuilt and/or
17 retrofitted with slam shuts approximately 147 GT pilot-operated stations.](#)
18 PG&E will continue modifying GT LVCRs/LVCMs to mitigate the common
19 failure mode OP events in the GT System. The modification of this
20 regulation equipment will be executed at a considerably reduced pace in
21 comparison to what was proposed in the 2023 GRC see fn. 2 on p. 4.2-6).

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TIME TO RESPOND ON SITE TO EMERGENCY NOTIFICATION

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4 **TIME TO RESPOND ON SITE TO EMERGENCY NOTIFICATION**

5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (4.3) Overview**

8 **1. Metric Definition**

9 Safety and Operational Metric (SOM) 4.3 – Time to Respond On-Site to
10 Emergency Notification is defined as:

11 *Average time and median time to respond on-site to a gas-related*
12 *emergency notification from the time of notification to the time a Gas Service*
13 *Representative (GSR) (or qualified first responder) arrived onsite.*
14 *Emergency notification includes all notifications originating from 911 calls*
15 *and calls made directly to the utilities' safety hotlines.*

16 The data used to determine the average time and median time shall be
17 provided in increments as defined in General Order 112-F 123.2 (c) as
18 supplemental information, not as a metric.

19 **2. Introduction of Metric**

20 Gas emergency response measures Pacific Gas and Electric
21 Company's (PG&E or the Company) ability to respond with urgency to
22 hazardous or unsafe situations that may be a threat to customer and public
23 safety. In some situations, GSRs respond to emergency situations as first
24 responders. Responding to emergency situations is PG&E's highest priority
25 so that PG&E can prevent or ameliorate hazardous situations. PG&E's goal
26 is to have a GSR on-site as quickly as possible for customer generated gas
27 odor calls. Faster response time to Emergency Notifications reduces the
28 length of emergent situations.

29 PG&E's GSRs respond annually to approximately 100,000 potential gas
30 emergencies, and approximately 500,000 total gas service customer
31 requests.. These requests include investigating reports of possible gas
32 leaks; carbon monoxide monitoring; Pilot re-lights; appliance safety checks;

1 and maintenance work, including Atmospheric Corrosion remediation and
2 regulator replacements.

3 Consistent with current practice, PG&E will continue to treat all
4 customer-reported gas odor calls as Immediate Response (IR) and will
5 attempt to respond to such calls within 60 minutes. To meet this goal,
6 PG&E utilizes industry best practices, such as: mobile data terminals,
7 real-time Global Positioning Systems, backup on-call technicians, and shift
8 coverage of 24 hours a day, seven days a week.

9 **B. (4.3) Metric Performance**

10 **1. Historical Data (2011-2025)**

11 Historical data is presented as a value in minutes for response time,
12 indicated as both an average and a median value for all Emergency
13 Notifications for each calendar year.

14 Data sets prior to 2014 come from historically submitted documentation;
15 data sets from 2014 forward come from the Customer Data Warehouse
16 system (a database for Field Automated Systems (FAS) data) and go
17 through a rigorous, multi-step audit process prior to submission to ensure
18 accuracy and precision.

19 **2. Data Collection Methodology**

20 The response time by PG&E is measured from the time PG&E is
21 notified—defined as the order creation time in Customer Care and Billing by
22 the contact center—to the time a GSR or a PG&E-qualified first responder
23 arrives on-site to the emergency location (including Business Hours and
24 After Hours). PG&E notification time is defined as when a gas emergency
25 order is created and timestamped.

26 Using PG&E's FAS, the average response time is measured for all IR
27 gas emergency orders generated where a GSR or qualified first responder is
28 required to respond.

29 The following IR gas emergency jobs are excluded in the total gas
30 emergency orders volume count:

- 1 • Level 2 and above emergencies;¹
- 2 • If the source is a non-planned release of PG&E gas, the original call is
- 3 included—the gas emergency itself—and all subsequent related orders
- 4 are excluded;
- 5 • If the source is either a planned release of PG&E gas or another
- 6 non-leak-related event, all related orders from the metric are excluded,
- 7 including the original call;
- 8 – If technician finds Grade 1 or Class A leak not previously identified
- 9 by Company personnel, the order will be included in the metric even
- 10 if the leak was clearly not the source of odor complaint.
- 11 • Duplicate orders for assistance;
- 12 – If it is confirmed that internal PG&E personnel made an IR for the
- 13 wrong address and there are two IRs made for one incident, we will
- 14 manually adjust the Taken Time of 2nd IR (the correct address) to
- 15 the actual time the call was created, and then exclude the 1st IR
- 16 (the incorrect address). For now, the Customer Data
- 17 Warehouse/Business Objectives team will have to manually adjust
- 18 the Taken Time.
- 19 • Cancelled orders;
- 20 • For multiple leak calls from the same Multi-Meter Manifold;²
- 21 • Unknown premise tag with no nearby gas facility; and
- 22 • If the FAS system is unavailable—such as during a tech down event—
- 23 the jobs cannot be created in our system, and are therefore, an
- 24 exception (not available to be included in the volume).

25 **3. Metric Performance for the Reporting Period**

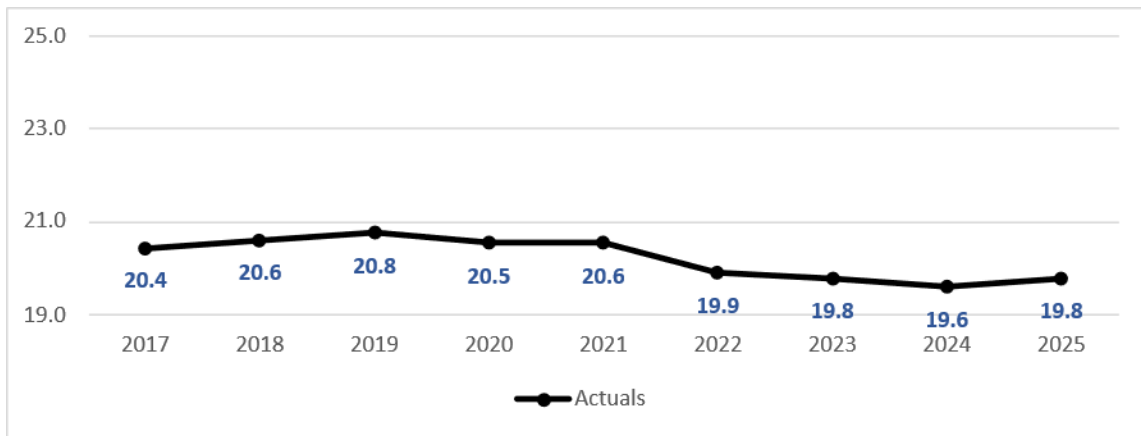
26 Since 2011, PG&E has improved and maintained strong performance in
27 this metric. In 2025, we have achieved an average response time of
28 19.8 minutes and a recorded median response time of 18.2 minutes,
29 compared to 19.6 minutes of average response time and 18.1 minutes of
30 median response time for the same period in 2024. Our performance in

1 Defined in the Gas Emergency Response Plan as a region-wide emergency event that may require 1-2 days for service restoration.

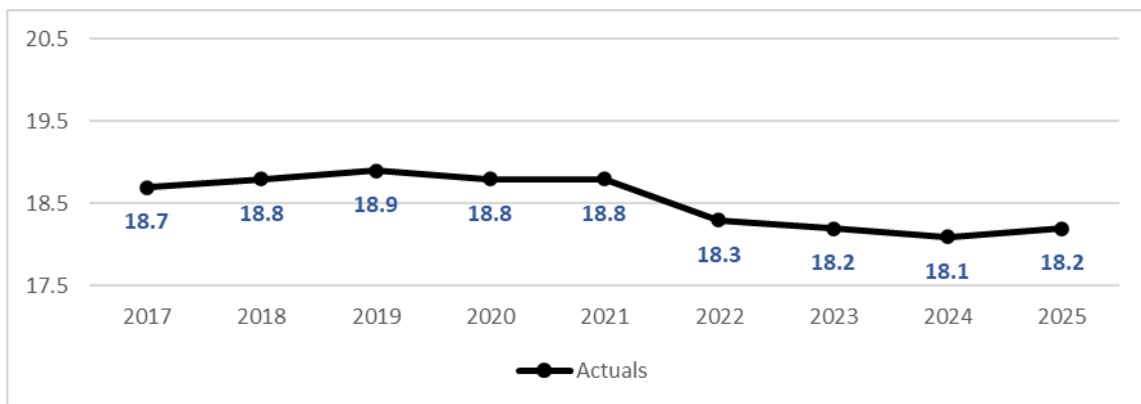
2 The first order is included, and all subsequent orders are excluded.

1 2025 outperformed target and was among our best response times over the
2 past nine years as shown in Figure 4.3-1. This was made possible by
3 continued focus by our Field Teams and Gas Dispatch deploying Lean
4 practices, cross collaboration and continued accountability and focus on this
5 metric.

**FIGURE 4.3-1
AVERAGE RESPONSE TIME
(2017-2025)**



**FIGURE 4.3-2
MEDIAN RESPONSE TIME
(2017-2025)**



1 **C. (4.3) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 None. Applying the same methodology as in the last SOMs report,
4 there will be a reduction to the 1-year and 5-year targets as described
5 below, reflecting a trend of improved performance.

6 **2. Target Methodology**

7 To establish the 1-year and 5-year targets, PG&E considered the
8 following factors:

- 9 • Historical Data and Trends: Comparable data is available starting in
10 2015. Performance has been consistent from 2015-2025 and maintains
11 top quartile;
- 12 • Benchmarking: The targets for average response time and median
13 response time are informed by available benchmarking data and targets
14 are set at a level consistent with strong performance;
- 15 • Regulatory Requirements: [No regulatory requirements that pertain to](#)
16 [setting Target Methodology.](#)
- 17 • Attainable Within Known Resources/Work Plan: Yes;
- 18 • Appropriate/Sustainable Indicators for Enhanced Oversight and
19 Enforcement: Yes, performance at or below the set targets is a
20 sustainable assumption for maintaining average and median response
21 time performance, plus room for non-significant variability; and
- 22 • Other Qualitative Considerations: None.

23 **3. 2026 Target**

24 [The 2026 target is to maintain performance better than or equal to](#)
25 [21.2 minutes for average response time and 19.5 minutes for median](#)
26 [response time](#), based on the factors described above. These targets
27 represent values that serve as appropriate indicator lights to signal a review
28 of potential performance issues. Targets should not be interpreted as
29 intention to worsen performance.

30 **4. 2030 Target**

31 [The 2030 target is to maintain performance better than or equal to](#)
32 [20.8 minutes for average response time and 19.1 minutes for median](#)

1 response time, based on the factors described above. Annual targets
2 should continue to be informed by available benchmarking data.

3 **D. (4.3) Performance Against Target**

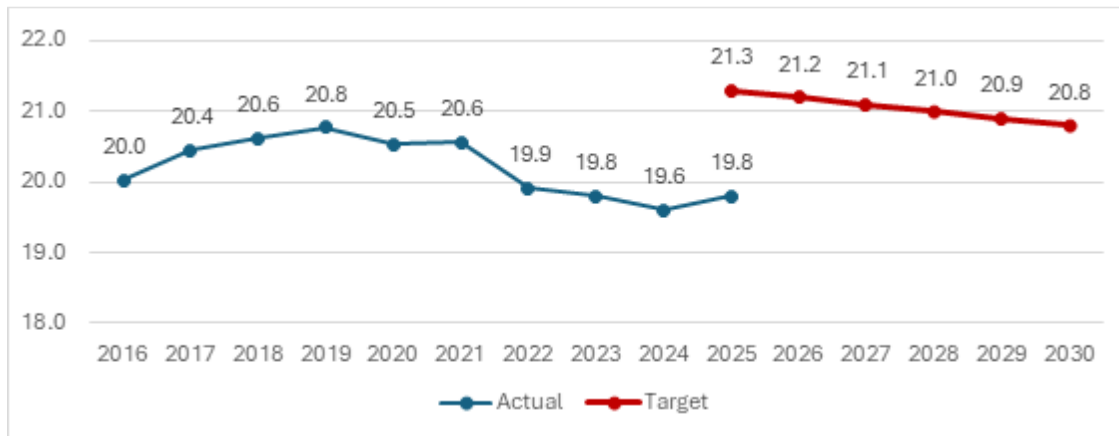
4 **1. Maintaining Performance Against the 1-Year Target**

5 As demonstrated in Figure 4.3-3 and 4.3-4, PG&E saw an average
6 response time of 19.8 minutes and a median response time of 18.2 minutes
7 in 2025 which outperformed the Company's 2025 target of 21.3 and
8 19.6 minutes, respectively.

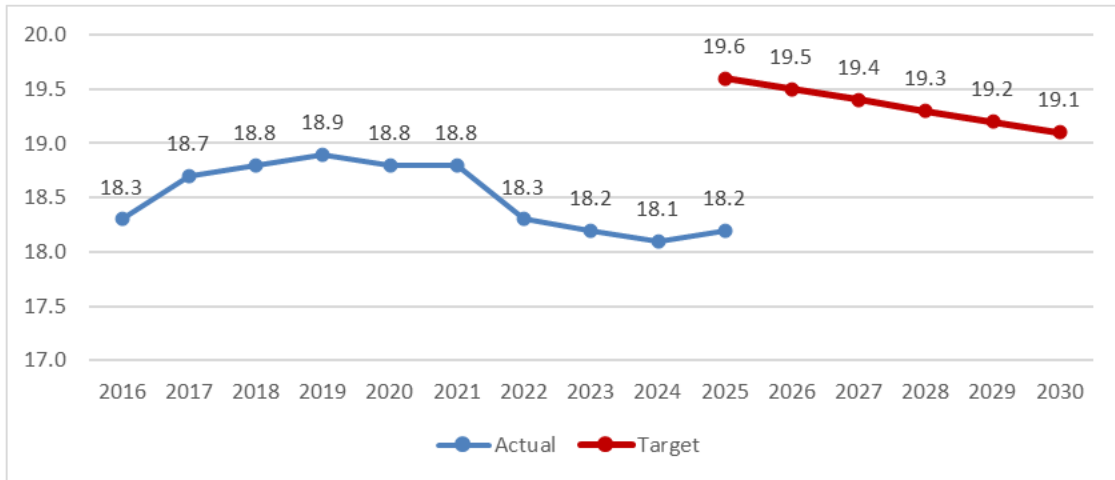
9 **2. Maintaining Performance Against the 5-Year Target**

10 As discussed in Section E below, PG&E continues to employ thorough
11 review, auditing, and cross-functional programs to maintain performance in
12 pursuit of the Company's 5-year target.

**FIGURE 4.3-3
AVERAGE RESPONSE TIME 2016-2025 AND TARGETS THROUGH 2030**



**FIGURE 4.3-4
MEDIAN RESPONSE TIME 2016-2025 AND TARGETS THROUGH 2030**



E. (4.3) Current and Planned Work Activities

Below is a summary description of the key activities that are tied to performance and their description of that tie.

- Field Service and Gas Dispatch: PG&E’s Field Service and Gas Dispatch partner together to respond to customer Gas Emergency (odor calls). There is a shared responsibility in the overall performance of this work. GSRs are deployed systemwide, 24 hours a day—utilizing an on-call as needed;
- Monitoring Controls: Activities which help us to maintain our Gas Emergency Response include continued focus and visibility in our Daily Operating Reviews, Weekly Operating Reviews, and Cross Functional Reviews. These help to illustrate several key drivers, including Dispatch Handle Time, Drive Time, and Wrap Time;
- Audits: PG&E performs audits on Emergency calls to identify opportunities.
- Data Analysis: Staffing and historical Gas Emergency Response volume are reviewed to help drive decisions. We utilize Best Practice of Dispatching to the closest resource. In addition, Dispatcher Ride Alongs with GSRs have been implemented to drive cross-functional understanding.

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5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (4.4) Introduction**

8 **1. Metric Definition**

9 Safety and Operational Metric (SOM) 4.4 – Gas Shut-In Time, Mains is
10 defined as:

11 *Median time to shut-in gas when an uncontrolled or unplanned gas*
12 *release occurs on a main. The data used to determine the median time*
13 *shall be provided in increments as defined in General Order 112-F 123.2 (c)*
14 *as supplemental information, not as a metric.*

15 **2. Introduction of Metric**

16 The measurement of Gas Shut in Time captures the median duration of
17 time required to respond to and mitigate potentially hazardous gas leak
18 conditions. These leak conditions are associated with the public safety risk
19 of loss of containment on Gas Distribution Main or Service. The term “shut
20 in” refers to the act of stopping the gas flow. It is important for the flow of
21 gas to be stopped to avoid consequences such as overpressure events or
22 explosions and so that work can be safely performed to make repairs in a
23 timely manner. Performance aims for faster response times as a measure
24 of prevention resulting in lower risk of an incident impacting public safety
25 and minimized interruption to the gas business and customers. It is
26 imperative that we promptly and effectively resolve any hazardous
27 conditions on our distribution network while balancing timeliness, customer
28 outages, and employee safety.

29 The timing for the response starts when the Pacific Gas and Electric
30 Company (PG&E, the Company, or the Utility) first receives the report of a
31 potential gas leak and ends when the Utility’s qualified representative
32 determines, per the Utility’s emergency standards, that the reported leak is
33 not hazardous, a leak does not exist, or the Utility’s representative

1 completes actions to mitigate a hazardous leak and render it as being
2 non-hazardous (i.e., by shutting-off gas supply, eliminating subsurface leak
3 migration, repair, etc.) per the Utility’s standards.

4 This metric measures the median number of minutes required for a
5 qualified PG&E responder to arrive onsite and stop the flow of gas as result
6 of damages impacting gas mains from PG&E distribution network. It does
7 not include instances where a qualified representative determines that the
8 reported leak is not hazardous, or a leak does not exist.

9 **B. (4.4) Metric Performance**

10 **1. Historical Data (2014 – 2025)**

11 [Historical data for Shut-In the Gas \(SITG\) Main metric is available for](#)
12 [the period 2014 through 2025](#). The data captures the median time that a
13 qualified first responder requires to respond and stop gas flow during
14 incidents involving an unplanned and uncontrolled release of gas on
15 distribution mains. This data includes incidents related to distribution main
16 pipelines and regulator stations because of third-party dig-ins, vehicle
17 impacts, explosion, pipe rupture, and material failure.

18 Before 2014, PG&E used a decentralized emergency process to
19 manage emergencies (i.e., each division used its own resources like
20 mappers, planners, among others to track and manage emergencies).
21 Similarly, support organizations like Dispatch, Mapping and Planning used
22 their own management tools to help schedule and manage emergency
23 information. Dispatch used a management tool called Outage Management
24 that recorded times at various stages of the process (i.e., when the
25 emergency call came in, when the Gas Service Representative arrived at
26 the site, when the leak was isolated, etc.). The Distribution Control Room
27 used a tool called Gas Logging System to record incoming information.

28 In 2014, a centralized process was implemented to allow Distribution,
29 Transmission, Dispatch, Planning and Mapping personnel to be co-located
30 and work together as a team to manage emergencies. This centralized
31 process also allowed the development of the Event Management Tool
32 (EMT) system.

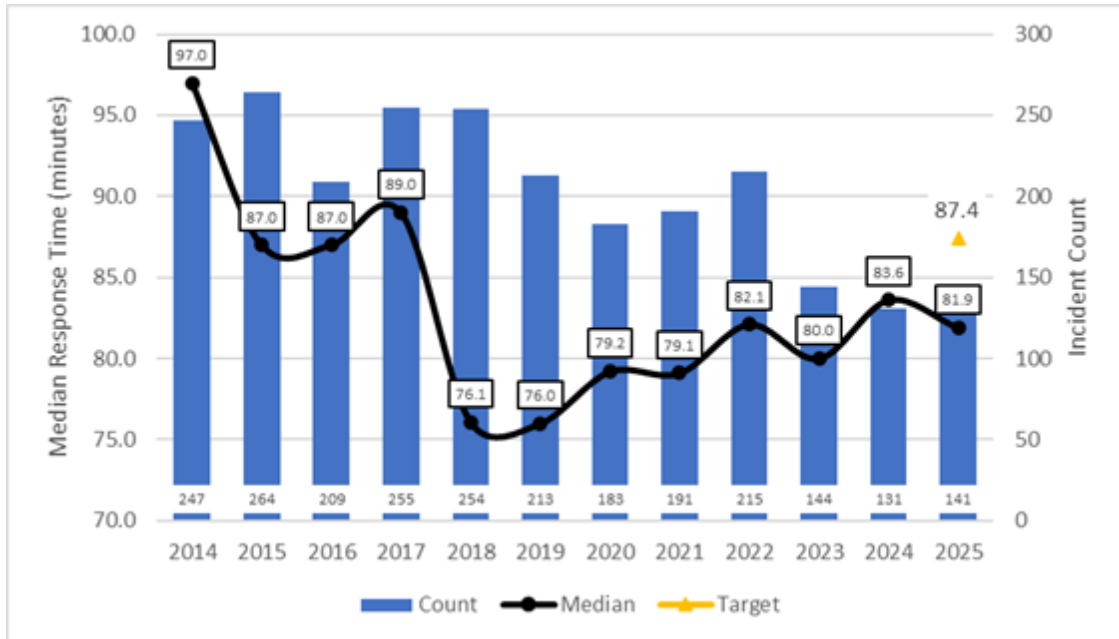
2. Data Collection Methodology

The EMT is currently used as the official system to track gas emergencies from start to finish. It is used by Dispatch and Gas Distribution Control Center teams to create emergency events and collect incident information and allows PG&E to run reports and retrieve historical information. The data captures the time that a qualified first responder requires to respond and stop gas flow during incidents involving an unplanned and uncontrolled release of gas on distribution mains. There are distinct types of incidents recorded in the EMT: explosions, corrosion, cross bore, pipe damage, dig-ins, evacuations, exposed pipe—no gas leak, fires, gas leaks (including Grade 1), high concentration areas, Hi/Lo pressures, material failure, pipe ruptures, vehicle impacts, among others. The EMT provides access to the latest information on an incident. All emergency data is consolidated and stored in one place.

3. Metric Performance for the Reporting Period

The range of data available to calculate the historical shut-in the gas median time for Mains is from 2014 through 2025. Over this reporting period, performance improved from 97 minutes in 2014 to 81.9 minutes median time in 2025. This long-term improvement is due to strategically prearranging construction crews in locations with high frequency of damages after business hours and weekends, understanding root causes for long shut-in time incidents and sharing best practices system wide during weekly performance review calls. These proactive actions resulted in a 2 percent improvement compared to 2024 results, despite a 51 percent increase in volume in the second half of 2025 compared to the first half and an increase in incidents with complex isolation strategies. This end of year result reverses the upward trend in performance in 2024 and aligns with the median average in the period 2022-2024. Although incident volume increased by 10 compared to 2024, the number of main incidents has continued a long-term downward trend since 2014, with significant improvement since 2022. This reduction is attributable to efforts put forth by damage prevention teams within PG&E.

**FIGURE 4.4-1
GAS SHUT-IN TIME, MAINS MEDIAN RESPONSE TIME
2014-2025**



Year	Count	Median	Target
2014	247	97.0	
2015	264	87.0	
2016	209	87.0	
2017	255	89.0	
2018	254	76.1	
2019	213	76.0	
2020	183	79.2	
2021	191	79.1	
2022	215	82.1	
2023	144	80.0	
2024	131	83.6	
2025	141	81.9	87.4

1 **C. (4.4) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 The 2026 target is set as the average of the annual median times over
4 the past 8-years (2018-2025) + 10 percent. The 2030 target will be flat,
5 aligned with 2026 target. This target is set to prioritize the safety of our
6 customers, employees, and to minimize service disruptions by allowing
7 PG&E personnel to make informed shut-in gas isolation decisions according
8 to field conditions rather than hastily take actions to shut-in the gas to meet
9 a more stringent target.

10 **2. Target Methodology**

11 To establish the 1-year and 5-year targets, PG&E considered the
12 following factors:

- 13 • Historical Data and Trends: The target is based on the average of the
14 medians in the period 2018-2025, plus 10 percent. The 8-year period is
15 being used to include recent performance in target setting calculations.
16 Furthermore, the 8-year period is used because 2018 was when the
17 FAS system was first utilized, and this data period is consistent with
18 current operational practices. The use of 10 percent allows for
19 non-significant variability, and accounts for the consideration of risk
20 during shut in events.
- 21 • Benchmarking: Direct benchmarking data is not available; therefore,
22 was not used in Target Methodology.
- 23 • Regulatory Requirements: No regulatory requirements that pertain to
24 setting Target Methodology.
- 25 • Attainable Within Known Resources/Work Plan: Yes;
- 26 • Appropriate/Sustainable Indicators for Enhanced Oversight and
27 Enforcement: Yes, performance at or below the average of the
28 2018-2025 annual median response time plus 10 percent is a
29 sustainable assumption for maintaining the improvement from
30 2018-2025 time frame plus room for non-significant variability; and
- 31 • Other Qualitative Considerations: Reducing shut in time to the lowest
32 possible result is not necessarily the best approach from a public safety
33 standpoint, and there is consideration of risk in various situations. In

1 some instances, the safest decision for our employees and the public is
2 to allow the gas to escape before crews shut it off.

3 **3. 2026 Target**

4 The 2026 target is to maintain performance at or lower than
5 87.7 minutes based on the factors described above. This target was
6 established to account for the consideration of risk in various situations and
7 aligns with our commitment to the safe operations of our assets. This target
8 represents an appropriate indicator light to signal a review of potential
9 performance issues. Target should not be interpreted as intention to worsen
10 performance.

11 **4. 2030 Target**

12 The 2030 target is to maintain performance at or lower than
13 87.7 minutes, based on the factors described above.

14 **D. (4.4) Performance Against Target**

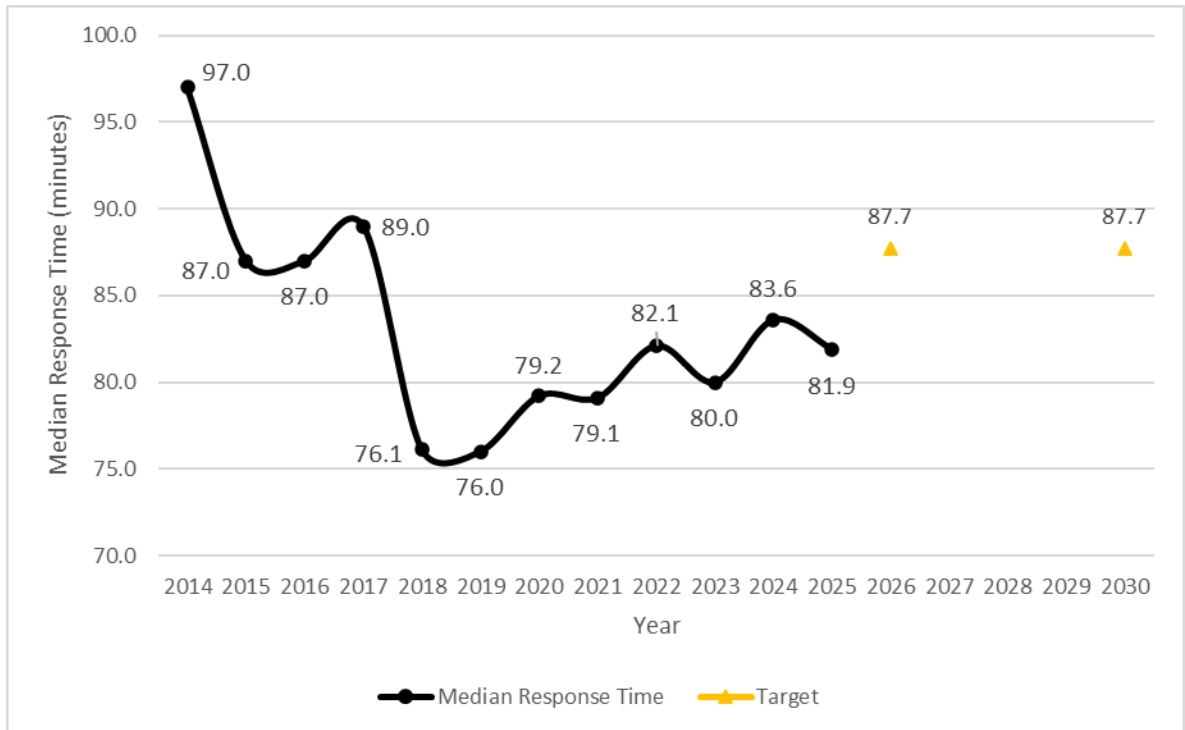
15 **1. Maintaining Performance Against the 1-Year Target**

16 As demonstrated in Figure 4.4-2, PG&E saw a median response time of
17 81.9 minutes in 2025, which is better than the Company's 1-year target of
18 87.4 minutes.

19 **2. Maintaining Performance Against the 5-Year Target**

20 As discussed in Section E, PG&E will continue mitigating the risk of loss
21 of containment on Gas Distribution Mains and Services and employing its
22 various programs to maintain performance in its efforts toward its 5-year
23 target.

**FIGURE 4.4-2
GAS SHUT IN TIME, MAINS MEDIAN RESPONSE TIME 2014-2025 AND
TARGETS 2026 THROUGH 2030**



E. (4.4) Current and Planned Work Activities

PG&E will continue to drive metric progress through performance management and supervisor-out-in-the-field initiatives. This metric will continue to mitigate the risk of loss of containment on Gas Distribution Main or Service by reducing distribution pipeline rupture with ignition.

The metric is supported by the following programs which focus on improving public safety: Field Services and Gas Maintenance and Construction (M&C).

- Gas Field Service: Field Service responds to gas service requests, which include investigation reports of possible gas leaks, carbon monoxide monitoring, customer requests for starts and stops of gas service, appliance pilot re-lights, appliance safety checks, as well as emergency situations as first responders; and
- Gas Maintenance and Construction: Gas M&C performs routine maintenance of PG&E’s gas distribution facilities, which includes emergency response due to dig-ins, as well as leak repairs.

The following process improvement initiatives have been implemented to help achieve metric results:

- 1 • Purchased and implemented emergency trailers in every division, allowing
2 for emergency equipment to be accessed quickly and easily;
- 3 • Purchased additional steel squeezers for 2-8" steel pipe (housed on
4 emergency trailers);
- 5 • Implemented Emergency Management tool (EM tool) to alert M&C of SITG
6 events when notified by third-party emergency organizations;
- 7 • Established concurrent response protocol (dispatch M&C and Field Service
8 resources) when notified by emergency agencies. Utility Procedure
9 TD-6100P-03 Major Gas Event Response: Fire, Explosion, and Gas Pipeline
10 Rupture was updated in 2021 to align with PG&E's response and
11 communication protocols; and
- 12 • Implemented 30-60-90-120+ minute communication protocols between Gas
13 Distribution Control Center and Incident Commander to ensure consistent
14 communication and issue escalation during events.

15 The following process improvement initiatives are on-going to help achieve
16 metric results:

- 17 • Daily Operating Reviews to identify deviations from the targets for the
18 previous 24 hours and identify countermeasures for continuous
19 improvement;
- 20 • Weekly Operating Review meetings weekly to share best practices and
21 review long duration events;
- 22 • Live action drills to simulate emergency scenarios, practicing isolation
23 procedures and documenting lessons learned;
- 24 • Time duration threshold to review incidents during Gas Daily Briefings
25 reduced from >120 to > 90 minutes;
- 26 • Dispatching two M&C crews along with an excavation truck to assist in
27 excavation timeliness;
- 28 • Dispatching locate and mark representative upon initial discovery to assist in
29 leak location prior to M&C crew arrival;
- 30 • Dispatch initiating underground service alerts followed by immediate
31 notification to allow for immediate marking of facilities;
- 32 • Increasing number of isolation valves along a pipeline for ease of isolation;
- 33 • Gas Distribution Control Center to contact M&C Superintendent at the
34 90-minute mark instead of the previous 120-minute protocol. This updated

- 1 guideline is to increase collaboration among different stakeholders and
2 improve delivery and implementation of isolation strategies;
- 3 • **Completed** update to EMT tool to have Gas Distribution Control Center and
4 Planning Team develop and communicate isolation strategies to
5 Maintenance and Construction crews < 30 minutes from initial incident
6 notification; and
 - 7 • **As of December 2025, when responding to gas dig-ins, Gas Dispatch sends**
8 **two Gas Service Representatives to respond. This is to allow greater focus**
9 **on continuous monitoring for potential gas migration and evacuations.**

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.5
GAS SHUT IN TIME, SERVICES

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.5
GAS SHUT IN TIME, SERVICES

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 4.5**
4 **GAS SHUT IN TIME, SERVICES**

5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (4.5) Overview**

8 **1. Metric Definition**

9 Safety and Operational Metric 4.5 – Gas Shut-In Time, Services is
10 defined as:

11 *Median time to shut-in gas when an uncontrolled or unplanned gas*
12 *release occurs on a service. The data used to determine the median time*
13 *shall be provided in increments as defined in General Order 112-F 123.2 (c)*
14 *as supplemental information, not as a metric.*

15 **2. Introduction of Metric**

16 The measurement of Gas Shut-In Time captures the median duration of
17 time required to respond to and mitigate potentially hazardous gas leak
18 conditions. These leak conditions are associated with the public safety risk
19 of loss of containment on Gas Distribution Main or Service. The term
20 “shut-in” refers to the act of stopping the gas flow. It is important for the flow
21 of gas to be stopped to avoid consequences such as overpressure events or
22 explosions and so that work can be safely performed to make repairs in a
23 timely manner. Performance aims for faster response times as a measure
24 of prevention resulting in lower risk of an incident impacting public safety
25 and minimized interruption to the gas business and customers. It is
26 imperative that we promptly and effectively resolve any hazardous
27 conditions on our distribution network while balancing timeliness, customer
28 outages, and employee safety.

29 The timing for the response starts when Pacific Gas and Electric
30 Company (PG&E, the Company, or the Utility) first receives the report of a
31 potential gas leak and ends when the Utility’s qualified representative
32 determines, per the Utility’s emergency standards, that the reported leak is
33 not hazardous, a leak does not exist, or the Utility’s representative

1 completes actions to mitigate a hazardous leak and render it as being
2 non-hazardous (e.g., by shutting-off gas supply, eliminating subsurface leak
3 migration, repair, etc.) per the Utility's standards.

4 This metric measures the median number of minutes required for a
5 qualified PG&E responder to arrive onsite and stop the flow of gas as result
6 of damages impacting gas [services](#) from PG&E distribution network. It does
7 not include instances where a qualified representative determines that the
8 reported leak is not hazardous, or a leak does not exist.

9 **B. (4.5) Metric Performance**

10 **1. Historical Data (2014-2025)**

11 [Historical data for Shut-In the gas \(SITG\) Services metric is available for](#)
12 [the period 2014-2025](#). The data captures the median time that a qualified
13 first responder is required to respond and stop gas flow during incidents
14 involving an unplanned and uncontrolled release of gas on services. This
15 data includes incidents related to distribution services and related
16 components such as service lines, valves, risers, and meters due to
17 third party dig-ins, vehicle impacts, explosion, pipe rupture, and material
18 failure.

19 Before 2014, PG&E used a decentralized emergency process to
20 manage emergencies, i.e., each division used its own resources like
21 mappers, planners, among others to track and manage emergencies.
22 Similarly, support organizations like Dispatch, Mapping and Planning used
23 their own management tools to help schedule and manage emergency
24 information. Dispatch used a management tool called Outage Management
25 that recorded times at various stages of the process (i.e., when the
26 emergency call came in, when the Gas Service Representative (GSR)
27 arrived at the site, when the leak was isolated, etc.). The Distribution
28 Control Room used a tool called Gas Logging System to record incoming
29 information.

30 In 2014, a centralized process was implemented to allow Distribution,
31 Transmission, Dispatch, Planning and Mapping personnel to be co-located
32 and work together as a team to manage emergencies. This centralized

1 process also allowed the development of the Event Management Tool
2 (EMT) system.

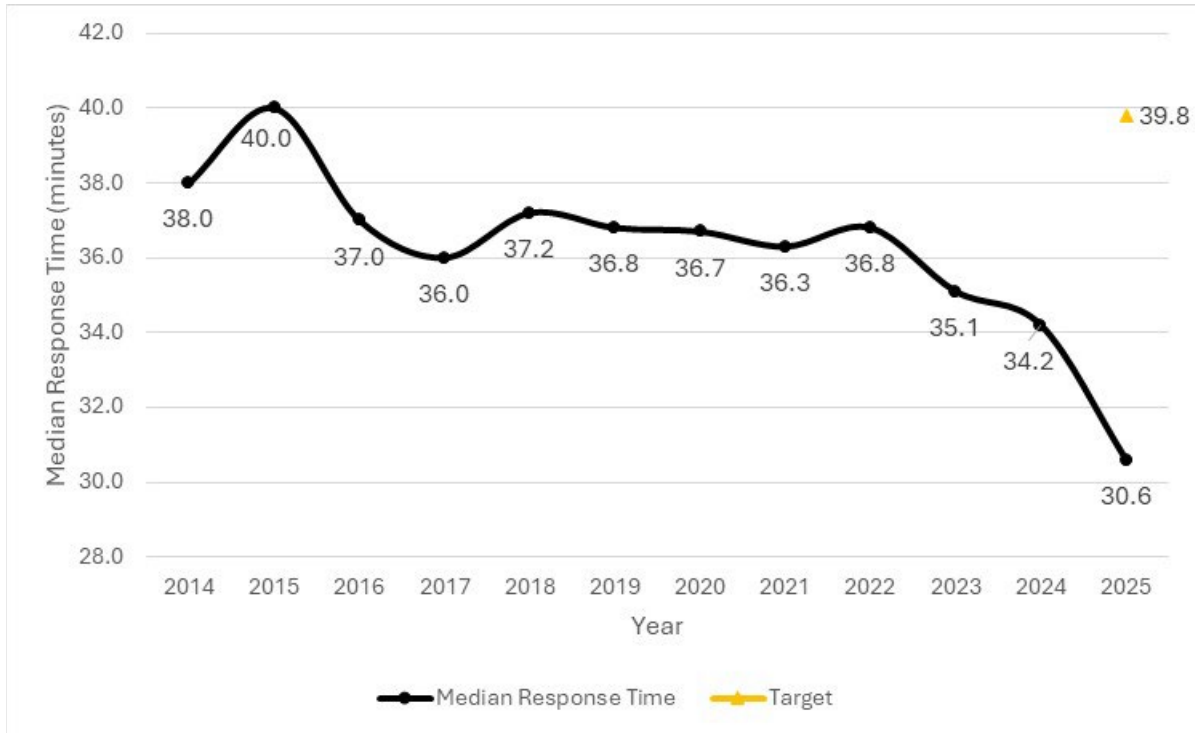
3 **2. Data Collection Methodology**

4 The EMT is currently used as the official system to track gas
5 emergencies from start to finish. The EMT is used by Dispatch and Gas
6 Distribution Control Center (GDCC) teams to create emergency events and
7 collect incident information and allows PG&E to run reports and retrieve
8 historical information. There are distinct types of incidents recorded in the
9 EMT: explosions, corrosion, cross bore, pipe damage, dig-ins, evacuations,
10 exposed pipe—no gas leak, fires, gas leaks (including Grade 1), high
11 concentration areas, Hi/Lo pressures, material failure, pipe ruptures, vehicle
12 impacts, among others. The EMT provides access to the latest information
13 on an incident. All emergency data is consolidated and stored in one place.

14 **3. Metric Performance for the Reporting Period**

15 The range of data available to calculate the historical SITG median time
16 for Services is from 2014 to 2025. Over this reporting period, performance
17 improved by 19.4 percent, decreasing from 38.0 minutes in 2014 to
18 30.6 minutes in 2025. This response time represents an improvement of
19 10.5 percent compared to 2024 end of year results. The continuous
20 improvement is due to strategically prearranging construction crews in
21 locations with high frequency of damages after business hours and
22 weekends, understanding root causes for long shut-in time incidents,
23 sharing best practices system wide during weekly performance review calls,
24 First Responders personnel squeezing services on arrival when possible,
25 and Excess Flow Valves stopping flow of gas when triggered.

**FIGURE 4.5-1
GAS SHUT IN TIME, SERVICES MEDIAN RESPONSE TIME 2014-2025**



1 **C. (4.5) 1-Year Target and 5-Year Target**

2 **1. Updates to 1-Year and 5-Year Targets Since Last Report**

3 The 2026 target is set as the average of the annual median times the
 4 past eight years (2018-2025) + 10 percent. The 2030 target will be flat
 5 aligned with 2026 target.

6 **2. Target Methodology**

7 To establish the 1-year and 5-year targets, PG&E considered the
 8 following factors:

- 9 • Historical Data and Trends: The target is based on the average of the
 10 annual medians in the period 2018-2025, plus 10 percent. The
 11 eight-year period is being used to include recent performance in target
 12 setting calculations. Furthermore, the eight-year period is used because
 13 2018 was when the Field Automation System was first utilized, and this
 14 data period is consistent with current operational practices. The use of
 15 10 percent allows for non-significant variability, and accounts for the
 16 consideration of risk during shut in events;

- 1 • Benchmarking: Direct benchmarking data is not available; therefore,
2 was not used in Target Methodology;
- 3 • Regulatory Requirements: No regulatory requirements that pertain to
4 setting Target Methodology;
- 5 • Attainable Within Known Resources/Work Plan: Yes;
- 6 • Appropriate/Sustainable Indicators for Enhanced Oversight and
7 Enforcement: Yes, performance at or below the average of the
8 2018-2025 annual median response time plus 10 percent is a
9 sustainable assumption for maintaining the improvement from 2018-2025
10 time-frame plus room for non-significant variability; and
- 11 • Other Qualitative Considerations: Reducing shut in time to the lowest
12 possible result is not necessarily the best approach from a public safety
13 standpoint, and there is consideration of risk in various situations. In
14 some instances, the safest decision for our employees and the public is
15 to allow gas to escape while we identify and perform the safest means of
16 isolating the gas.

17 3. 2026 Target

18 The 2026 target is to maintain performance at or lower than
19 39.0 minutes based on the factors described above. This target was
20 established to account for the consideration of risk in various situations and
21 aligns with our commitment to the safe operations of our assets. This target
22 represents an appropriate indicator light to signal a review of potential
23 performance issues. Target should not be interpreted as intention to worsen
24 performance.

25 4. 2030 Target

26 The 2030 target is to maintain performance at or lower than
27 39.0 minutes based on the factors described above.

28 D. (4.5) Performance Against Target

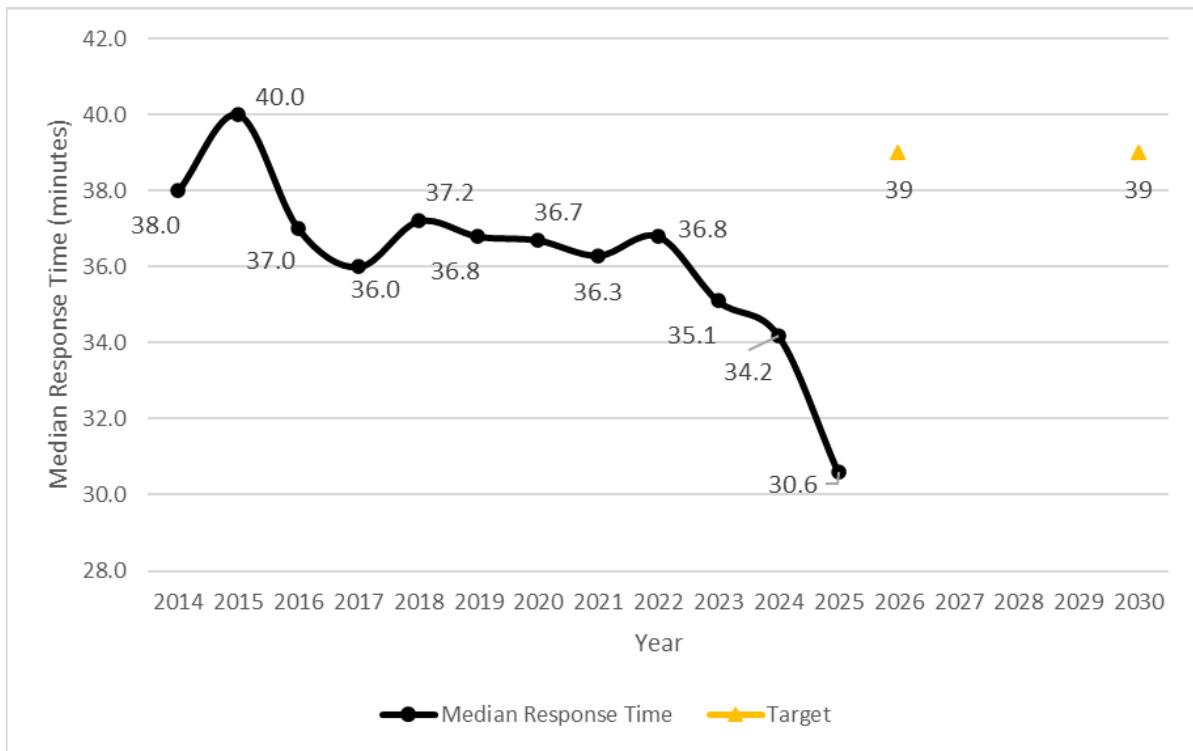
29 1. Maintain Performance Against the 1-Year Target

30 As demonstrated in Figure 4.5-2, PG&E saw a median response time of
31 30.6 minutes in 2025, which is better than the Company's 1-year target of
32 39.8 minutes.

1 **2. Maintain Performance Against the 5-Year Target**

2 As discussed in Section E, PG&E will continue mitigating the risk of loss
3 of containment on Gas Distribution Mains and Services and employing its
4 various programs to maintain performance in its efforts toward its 5-year
5 target.

**FIGURE 4.5-2
GAS SHUT IN TIME, SERVICES MEDIAN RESPONSE TIME 2014-2025 AND
TARGETS FROM 2026 AND 2030**



6 **E. (4.5) Current and Planned Work Activities**

7 PG&E will continue to drive metric progress through performance
8 management and supervisor-out-in-the-field initiatives. This metric will continue
9 to mitigate the risk of loss of containment on Gas Distribution Main or Service by
10 reducing distribution pipeline rupture with ignition.

11 The metric is supported by the following programs which focus on improving
12 public safety: Field Services and Gas Maintenance and Construction (M&C).

- 13 • Gas Field Service: Field Service responds to gas service requests, which
14 include investigation reports of possible gas leaks, carbon monoxide
15 monitoring, customer requests for starts and stops of gas service, appliance

1 pilot re-lights, appliance safety checks, as well as emergency situations as
2 first responders; and

- 3 • Gas M&C: Gas M&C performs routine maintenance of PG&E's gas
4 distribution facilities, which includes emergency response due to dig-ins, as
5 well as leak repairs.

6 The following process improvement initiatives have been implemented to
7 help achieve metric results:

- 8 • Enhanced plastic squeeze capability from approximately 50 percent to all
9 GSRs for < 1" plastic pipe;
- 10 • Purchased and implemented emergency trailers in every division, allowing
11 for emergency equipment to be accessed quickly and easily;
- 12 • Purchased additional steel squeezers for 2-8" steel pipe (housed on
13 emergency trailers);
- 14 • Implemented Emergency Management tool to alert M&C of SITG events
15 when notified by third-party emergency organizations;
- 16 • Established concurrent response protocol (dispatch M&C and Field Service
17 resources) when notified by emergency agencies. Utility Procedure
18 TD-6100P-03 Major Gas Event Response: Fire, Explosion, and Gas Pipeline
19 Rupture was updated in 2021 to align with PG&E's response and
20 communication protocols;
- 21 • Implemented and updated 30-60-90-120+ minute communication protocols
22 between GDCC and Incident Commander to ensure consistent
23 communication and issue escalation during events; and
- 24 • Continue to explore alternatives to improve overall response time such as
25 completion of pilot program to have General Construction crews provide
26 emergency support if M&C crews are not available.

27 The following process improvement initiatives are on-going to help achieve
28 metric results:

- 29 • Daily Operating Reviews to identify deviations from the targets for the
30 previous 24 hours and identify countermeasures for continuous
31 improvement;
- 32 • Weekly Operating Review meetings weekly to share best practices and
33 review long duration events;

- 1 • Provide yearly plastic squeeze training for all Field Service employees as
- 2 part of Operator Qualification refresher;
- 3 • Live action drills to simulate emergency scenarios, practicing isolation
- 4 procedures and documenting lessons learned;
- 5 • Time duration threshold to review incidents during Gas Daily Briefings
- 6 reduced from >120 to > 90 minutes;
- 7 • Dispatching locate and mark representative upon initial discovery to assist in
- 8 leak location prior to M&C crew arrival; and
- 9 • Dispatch initiating underground service alerts followed by immediate
- 10 notification to allow for immediate marking of facilities.

11 As of December 2025, when responding to gas dig-ins, Gas Dispatch sends
12 two GSR to respond. This is to allow greater focus on continuous monitoring for
13 potential gas migration and evacuations.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.6
UNCONTROLLED RELEASE OF GAS ON
TRANSMISSION PIPELINES

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.6
UNCONTROLLED RELEASE OF GAS ON
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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 4.6**
4 **UNCONTROLLED RELEASE OF GAS ON**
5 **TRANSMISSION PIPELINES**

6 The material updates to this chapter since the September 30, 2025 report are
7 identified in blue font.

8 **A. (4.6) Overview**

9 **1. Metric Definition**

10 Safety and Operational Metrics (SOM) 4.6 – Uncontrolled Release of
11 Gas on Transmission Pipelines is defined as:

12 *The number of leaks, ruptures, or other loss of containment on*
13 *transmission lines for the reporting period, including gas releases reported*
14 *under Title 49 Code of Federal Regulations (CFR) Part 191.3.*

15 **2. Introduction of Metric**

16 This metric tracks the total number of Grade 1, 2, and 3 leaks, as well as
17 ruptures and other losses of containment on GT Pipelines which include;
18 Gas Transmission (GT) pipelines and Distribution Service Lines (DSL).
19 Leaks are an important indicator because each leak’s uncontrolled flow of
20 gas into the surrounding area can increase the consequence of incidents
21 and cause disruption to our customers’ gas service. Leaks are also an
22 important indicator in evaluating the mitigations’ and controls’ effectiveness
23 on maintaining or reducing risk. **Furthermore, leaks and uncontrolled**
24 **release of gas result in carbon emissions into the environment.**

25 **B. (4.6) Metric Performance**

26 **1. Historical Data (2016 – 2023)**

27 Pacific Gas and Electric Company (PG&E) started by reviewing six
28 years of historical data, comprising the years 2016 through 2021. In
29 evaluating the data, PG&E noted changes in detection capabilities and
30 frequency of surveys for the years after 2018. **Originally, the data used to**
31 **develop the annual targets for these metrics was focused on 2019-2021.**
32 **However, there has been a decreasing trend of leaks since the peak value**

1 of 4012 leaks in 2020. This is primarily due to PG&E's efforts to enhance
2 cathodic protection, mitigate threats, and identify integrity concerns before
3 leaks occur. For this reason, the data used to develop this metric is now
4 focused on 2021-2023 to represent the enhancements implemented in
5 recent years.

6 **2. Data Collection Methodology**

7 Leak data is managed and pulled by the PG&E Leak Survey Process
8 team. This data is extracted from PG&E's GCM013 report using SAP data.
9 This report aggregates all leaks found during the reporting period and
10 includes the location, line type, and grade of leak. Original grade is used for
11 the metric criteria because it is not subject to change even if the leak
12 condition or status changes due to regrade, cancelation, or repair.

13 In addition, transmission incidents reported to Pipeline and Hazardous
14 Materials Safety Administration (PHMSA) that meet the incident reporting
15 definition in CFR 191.3 are considered for metric inclusion. These events
16 may be leaks, ruptures, or other incidents related to uncontrolled gas
17 release. For each reporting period, PG&E will review any transmission
18 incidents reported to PHMSA and compare against the GCM013 leaks using
19 incident location (Route/MP, latitude/longitude, street address) and
20 date/time of incident to remove any duplicates between the two datasets.

21 To ensure all transmission leaks from the previous month are reported,
22 the GCM013 tool is executed, at earliest, on the 1st business day after the
23 previous month's end to account for that month's leaks, thus providing a
24 "snapshot" of the Metric's monthly performance. This improvement was
25 implemented in the March 2024 report after it was identified by PG&E
26 Internal Audit in February 2024 that pulling the monthly snapshot on the last
27 days of the month could lead to missing leaks for the final days of that
28 month.

29 An additional QC was implemented in January 2025 to account for
30 newly added and cancelled leaks from the previous year's monthly
31 snapshots. The GCM013 tool is executed in January of the new year to
32 reconcile all the previous year's leaks. This will account for any missed
33 leaks that may have been added, and any leak notifications that were

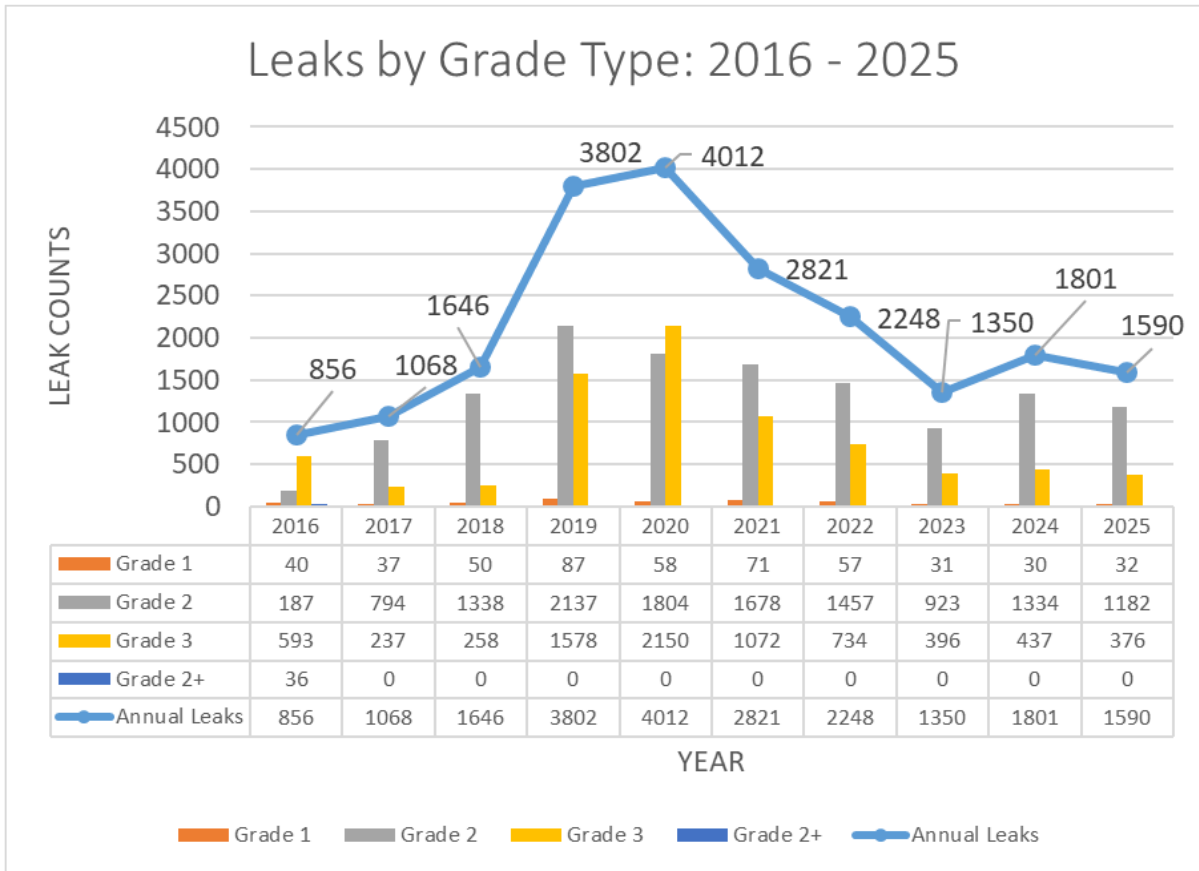
1 cancelled after the monthly snapshot(s) were established. This
2 reconciliation is then utilized for the year end reporting period.

3 **3. Metric Performance for the Reporting Period**

4 The annual count of all leaks, ruptures, and loss of containment had
5 been increasing steadily since 2016, with the largest increase seen from
6 2018 to 2019. This increase was primarily due to a California Air Resources
7 Board (CARB) rule change which requires more frequent leak surveys. The
8 increase of leak surveys improved visibility and resulted in a larger leak
9 dataset relative to prior years. In March 2017, CARB finalized and approved
10 the Oil and Gas Greenhouse Gas (GHG) Rule codified under California
11 Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10,
12 “Climate Change,” Article 4. Effective January 1, 2018, the GHG Rule
13 covers emission standards, including, but not limited to, stringent leak
14 detection and repair requirements for facilities in certain Oil and Gas
15 sectors. This rule applies to PG&E’s underground natural gas storage
16 facilities and GT compressor stations. As a result, PG&E performs a
17 quarterly leak survey at the impacted facilities and performs leak repairs
18 based on CARB’s repair timelines.

19 PG&E ended 2025 with 1590 transmission leaks, which is a significant
20 improvement from the 2020 peak of 4012 leaks. This difference shows
21 about 60 percent fewer leaks from 2020 to 2025, resulting from PG&E’s
22 efforts to enhance cathodic protection, mitigate threats, and identify integrity
23 concerns before leaks occur. The leak count from 2025 is below the target
24 of 3440 unintentional releases by about 54 percent, showing that the
25 practices resulting in the 2019 and 2020 peaks have been enhanced, and
26 that the prior target is overly conservative in comparison with the recent
27 trend of leak data. The new target for 2026 will utilize the three year
28 average from 2021 to 2023 for a better representation of a performance
29 threshold.

**FIGURE 4.6-1
LEAKS BY GRADE TYPE: 2016 – 2025**



Note: Figure 4.6-1 includes the GCM-13 reported leak counts.

C. (4.6) 1-Year Target and 5-Year Target

1. Updates to 1- and 5-Year Targets Since Last Report

With the updated target methodology described in the section below; the revised 2026 and 2030 targets are 2140 and 2055 leaks, respectively.

2. Target Methodology

To establish the updated 1-Year and 5-Year targets, PG&E considered the following factors:

- Historical Data and Trends:** The targets are based on annual 1 percent reduction starting with the average of the three years of historical data between 2021-2023. Those three years were used as the timeframe most representative of current leak survey and risk mitigation practices.

1 The most recent three years were not used as the target because they
2 represent good performance, not the threshold for minimal performance.

- 3 • Benchmarking: Not available;
- 4 • Regulatory Requirements: None;
- 5 • Attainable Within Known Resources/Work Plan: Yes;
- 6 • Appropriate/Sustainable Indicators for Enhanced Oversight and
7 Enforcement: Yes, performance at or below the average from
8 2021-2023 is a sustainable assumption and allows for non-significant
9 variability; and
- 10 • Other Qualitative Considerations: The target also takes into
11 consideration that the results for this metric may fluctuate based on
12 miles of leak surveys performed, changing CARB requirements, and
13 recommended risk mitigation. The number of leaks found has a
14 correlative relationship to the miles of leak surveys performed and
15 number of components surveyed. While this is a positive impact for risk
16 visibility and mitigation, it can be a driver of varying trends appearing in
17 the results. Similarly, improved risk mitigation such as enhanced
18 cathodic protection can contribute to lower leak counts by helping to
19 identify integrity concerns before leaks occur.

20 3. 2026 Target

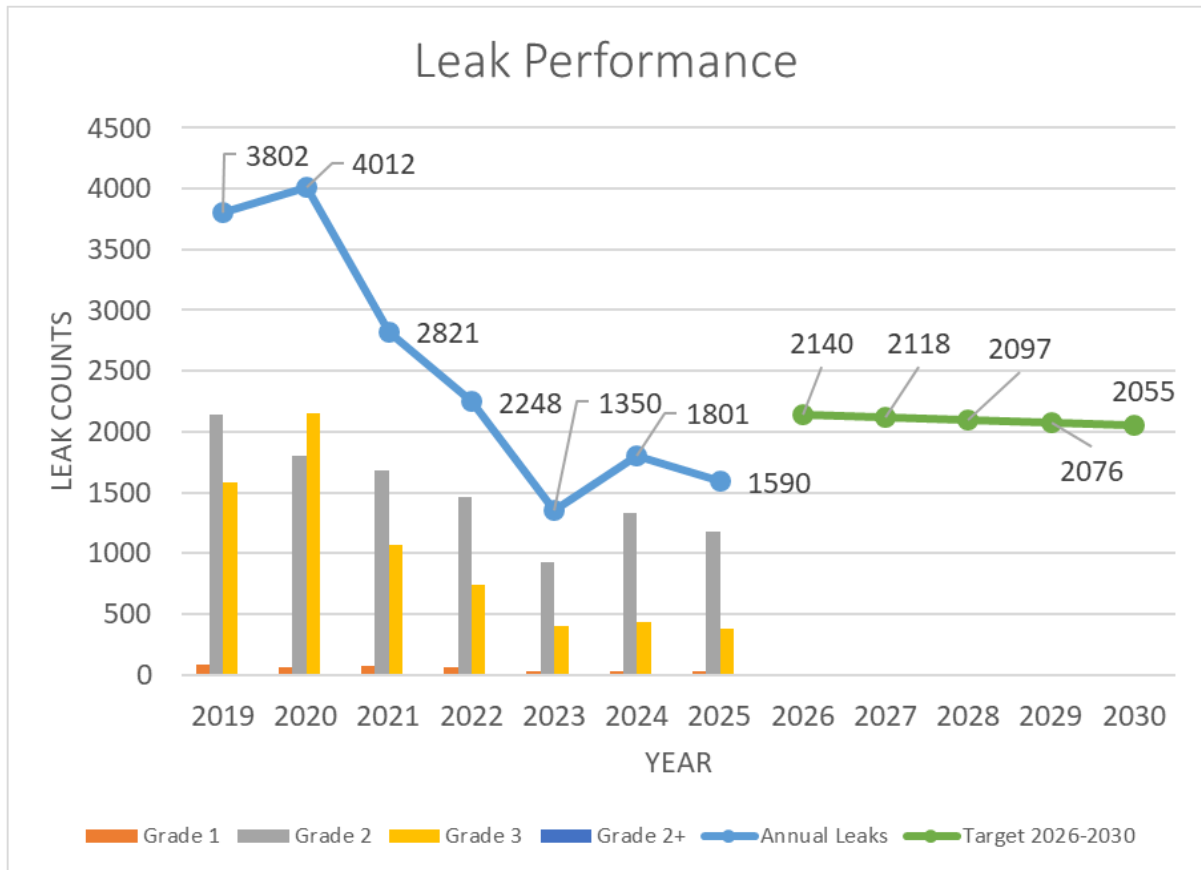
21 The 2026 target is to maintain performance at or lower than 2140 leaks,
22 ruptures, or other loss of containment on GT pipelines. This proposed target
23 is based on the average of leaks found from 2021-2023. A 1 percent annual
24 reduction is then applied to this baseline target which could be impacted by
25 the factors described above (see Figure 4.6-2). This new target
26 methodology recognizes that the practices resulting in the 2019 and 2020
27 peaks have been enhanced, and the minimal performance expectation
28 should be adjusted to reflect the current processes. This new target utilizes
29 the decreasing trend from 2021 to 2023, and results in a target that better
30 represents a threshold for performance concern.

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4. 2030 Target

The 2030 target is to maintain performance at or lower than 2055 events, which reflects a continued focus on improvement year over year and is based on the factors described above (see Figure 4.6-2).

**FIGURE 4.6-2
LEAKS BY GRADE TYPE 2019 – 2025 AND TARGETS FROM 2026 – 2030**



Note: Figure 4.6-2 includes the GCM-13 reported leak counts.

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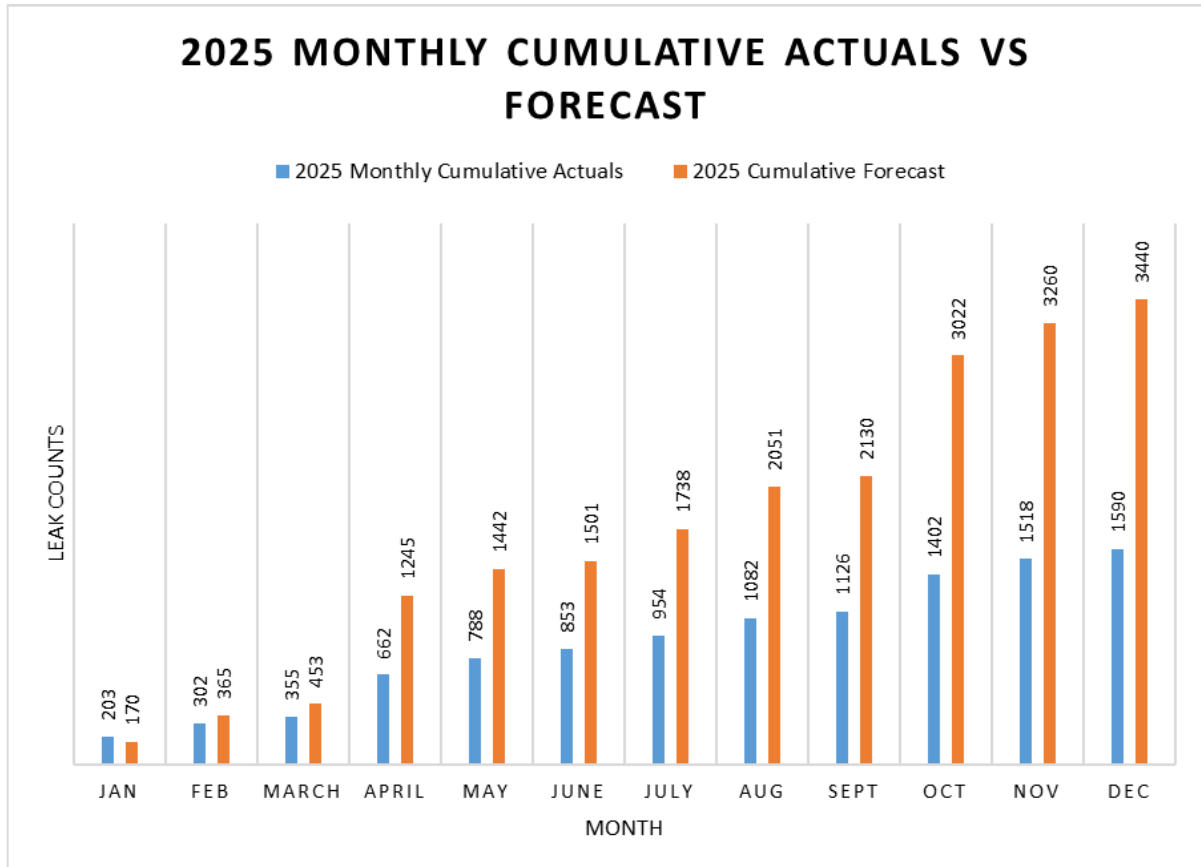
D. (4.6) Performance Against Target

1. Maintaining Performance Against the 1-Year Target

Figure 4.6-2 demonstrates that PG&E identified 1590 unintended gas release events in 2025, (in addition to 1 PHMSA reportable incident from March 2025), which is about 54 percent below the company's original one-year target of 3440 unintended gas release events. The updated target methodology in Figure 4.6-2 shows a less conservative threshold that

1 utilizes a decreasing trend of leaks and better represents a threshold for
2 performance concern if an increase of leaks occurs.

**FIGURE 4.6-3
UNCONTROLLED RELEASE OF GAS INCIDENTS IN 2025**

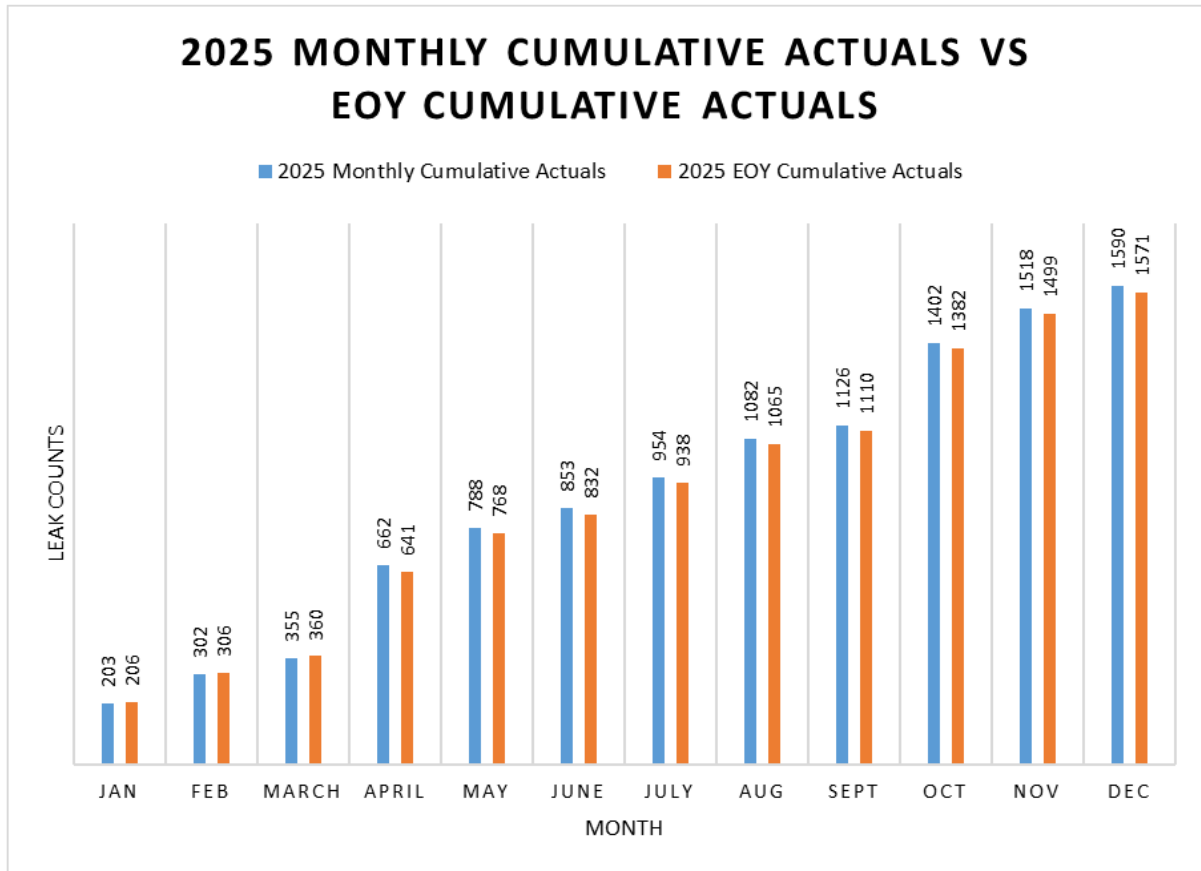


Note: Figure 4.6-3 does not contain the one count of PHMSA gas release reportable incident from March 2025.

2. Progress Towards/Deviation From the 5-Year Target

Discussed in Section E, PG&E continues using surveys, assessments, risk mitigation, [cathodic protection](#), and its programs to achieve the Company's 5-year performance target. [Figure 4.6-3](#) shows that the annual target from 2025 based on the 2024 monthly leak distribution is very high in comparison to the 2025 monthly leak counts. As described above, the leak counts show that the previous target methodology was overly conservative by about 46 percent.

FIGURE 4.6-4
END OF YEAR (EOY) VS MONTHLY SNAPSHOTS FOR UNCONTROLLED RELEASE OF GAS



Note: Figure 4.6-4 does not contain the one count of PHMSA gas release reportable incident from March 2025.

1 As discussed in Section B, an end-of-year snapshot was taken in
2 January 2026 to compare the leak counts from 2025 to all the monthly
3 snapshots that were previously taken. Figure 4.6-4 confirms 1571 leaks
4 from the end-of-year snapshot in comparison to the 1590 leaks from the
5 monthly snapshots, showing a difference of 19 leaks. When looking at the
6 individual months, the monthly and EOY snapshots fluctuate in terms of
7 which is higher for leak counts. This fluctuation has to do with leaks that
8 were either added or cancelled after the monthly snapshots were taken,
9 which is accounted for in the EOY snapshot leak counts. When comparing
10 the EOY snapshot count of 1571 leaks to the 2025 target of 3440 leaks, the
11 leak count is still about 54 percent below the target, which aligns closely with
12 the monthly snapshots despite the leak additions and cancellations.

1 **E. (4.6) Current and Planned Work Activities**

2 The primary programs that support the risk reduction goals of this metric are
3 Transmission Integrity Management and Leak Management.

- 4 • Transmission Integrity Management: The Integrity Management Program
5 provides the tools and processes for risk ranking and prioritization of
6 remediation efforts. This program enables PG&E to focus on identifying and
7 remediating threats to its system. The Transmission Integrity Management
8 Program (TIMP) assesses the threats on every segment of transmission
9 pipe, evaluates the associated risks, and acts to prevent or mitigate these
10 threats. The TIMP approach for assessing risk is based on methodologies
11 consistent with American Society of Mechanical Engineers B31.8S and is
12 compliant with 49 CFR Part 192 Subpart O. Many of PG&E's programs that
13 mitigate and control transmission pipe asset risks are developed and
14 managed within the TIMP program. Examples of assessments or mitigative
15 work that contribute to reducing or preventing significant incidents include
16 strength testing, inline inspection, direct assessment, direct examination,
17 pipe replacement, [cathodic protection, and accelerated leak survey](#).
18 • Leak Management: The Leak Management Program addresses the risk of
19 Loss of Containment (LOC) by finding and fixing leaks. PG&E performs leak
20 survey of the GT and storage system twice per year, by either ground or
21 aerial methods in accordance with General Order 112-F. Leak surveys of
22 pipeline and equipment are commonly accomplished on foot or vehicle, by
23 operator-qualified personnel, using a portable methane gas leak detector.
24 Aerial leak surveys, in remote locations and areas difficult to access on the
25 ground, are performed by helicopter using Light Detection and Ranging
26 Infrared technology. Additional activities that complement the TIMP include
27 risk-based leak surveys, mobile leak quantification, and replacing/removing
28 high bleed pneumatic devices at compressor stations and storage facilities.
29 • In-line Inspection (ILI): In-line inspection is the most effective integrity
30 assessment tool for identifying and repairing pipe anomalies whose
31 continued growth would result in loss of containment. To utilize ILI, a
32 pipeline must be upgraded to allow the passage of the ILI tools. PG&E
33 performs ILI upgrades at a pace of about 4 upgrades per year. [At the end of
34 2025, PG&E has 60.55 percent of the GT system capable of ILI.](#) Work

1 during the 2023 rate case period is contributing to PG&E’s overall goal of
2 upgrading the system so that 65 percent of PG&E’s GT pipeline miles are
3 capable of ILI by end of 2038. None of the DSL pipe mileage that was
4 transferred out of GT per TransDef is piggable via traditional ILI methods,
5 and is not planned for future pigging upgrades.

- 6 • External Corrosion Direct Assessment (ECDA): Per the 2023-2026 rate
7 case period, PG&E expected to conduct ECDA indirect inspections on
8 approximately 268 miles of transmission pipeline in HCAs. 39 miles were
9 assessed in 2023, 37 miles were assessed in 2024 and 79 miles in 2025.
10 The lower mileage of transmission pipe assessed via ECDA in comparison
11 to the expected 268 miles is due to decisions to utilize other assessment
12 technologies, which resulted in less performed than forecast. ECDA indirect
13 inspections assess the cathodic protection and coating condition of pipelines
14 to identify locations for direct examinations of the pipeline. These
15 inspections and direct examinations inform the understanding of the
16 pipelines’ condition and inform any mitigations needed to enhance cathodic
17 protection, ensure external corrosion and the resulting leaks are minimized.
- 18 • Close Interval Survey (CIS): PG&E also has a CIS Program targeted at
19 monitoring the effectiveness of the transmission pipelines’ cathodic
20 protection (CP) systems by reading the CP levels between the annual
21 monitoring locations. This program annually assesses 3-10 percent of
22 PG&E’s gas transmission pipelines. Assessing the levels of CP between
23 test points provides increased confidence that the readings obtained at test
24 stations reflect conditions along the entire system and enable PG&E to
25 make CP adjustments where CIS indicates additional CP is warranted. CIS
26 is recognized as a best practice to assess CP along the entire pipeline,
27 verify electrical isolation, and identify potential interference gradients that
28 may compromise the integrity of the system.
- 29 • Strength Testing: Strength tests reduce significant loss of containment
30 incidents like ruptures by confirming the integrity of a pipeline at its
31 Maximum Allowable Operating Pressure (MAOP). They are conducted as a
32 qualifying test for MAOP reconfirmation and for integrity assessments when:
33 – Class location changes.

- 1 – A section of pipe lacks a Traceable, Verifiable, and Complete (TVC)
- 2 record of a test that supports the MAOP, per 192.624 and PUC 958; or
- 3 – As an integrity assessment to verify pipeline integrity.

4 Currently, approximately 88 percent of PG&E’s GT pipelines have a TVC
5 strength test. For the pipelines lacking TVC records, PG&E is prioritizing the
6 pipelines in HCAs, MCAs, Class 3 and 4 in order to meet the 2028 and 2035
7 compliance dates specified in 192.624. After these compliance dates are
8 met, PG&E will work to complete the remaining transmission pipelines
9 required by PUC 958.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.7
TIME TO RESOLVE HAZARDOUS CONDITIONS

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 4.7
TIME TO RESOLVE HAZARDOUS CONDITIONS

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 4.7**
4 **TIME TO RESOLVE HAZARDOUS CONDITIONS**

5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (4.7) Overview**

8 **1. Metric Definition**

9 Safety and Operational Metric (SOM) 4.7 – Time to Resolve Hazardous
10 Conditions (TRHC) is described as:

11 *Median response time to resolve Grade 1 leaks. Time starts when the*
12 *utility first receives the report and ends when a utility’s qualified*
13 *representative determines, per the utility’s emergency standards, that the*
14 *reported leak is not hazardous or the utility’s representative completes*
15 *actions to mitigate a hazardous leak and render it as being non-hazardous*
16 *(i.e., by shutting-off gas supply, eliminating subsurface leak migration,*
17 *repair, etc.) per the utility’s standards.*

18 The data used to determine the Median Time shall be provided in
19 increments as defined in General Order 112-F 123.2 © as supplemental
20 information, not as a metric.

21 **2. Introduction of Metric**

22 The measurement of TRHC captures the duration of time required to
23 mitigate hazardous gas leak conditions. These leak conditions are
24 associated with the public safety risk of loss of containment on Gas
25 Distribution Main or Service. Performance aims for faster resolution times
26 as a measure of prevention resulting in lower risk of an incident impacting
27 public safety and minimized interruption to the gas business and customers.
28 It is imperative that we promptly and effectively resolve any hazardous
29 conditions on our distribution network while balancing timeliness, customer
30 outages, and employee safety. Long duration blowing gas events have the
31 potential to negatively impact public safety if an ignition source is present, as
32 well as it poses a risk if migration into sub-surface structures occurs.

1 **B. (4.7) Metric Performance**

2 **1. Historical Data (2018 – 2025)**

3 [Historical data for TRHC Grade 1 Leaks metric is available for 2018 –](#)
4 [2025](#). The data captures the time that a qualified first responder requires to
5 respond and stop gas flow due to Grade 1 leaks. This data includes leaks
6 identified in our distribution system and includes all facility types,
7 i.e., customer facilities, service and main pipelines, meters, regulator
8 stations, service risers, valves. It includes leaks identified by Pacific Gas
9 and Electric Company (PG&E or the Company) personnel only and with a
10 final resolution of leak repaired.

11 Before 2014, PG&E used a decentralized emergency process to
12 manage emergencies (i.e., each division used its own resources like
13 mappers, planners, among others to track and manage emergencies).
14 Similarly, support organizations like Dispatch, Mapping and Planning used
15 their own management tools to help schedule and manage emergency
16 information. Dispatch used a management tool called Outage Management
17 that recorded times at various stages of the process (i.e., when the
18 emergency call came in, when the Gas Service Representative arrived at
19 the site, when the leak was isolated, etc.). The Distribution Control Room
20 used a tool called Gas Logging System to record incoming information.

21 In 2014, a centralized process was implemented to allow Distribution,
22 Transmission, Dispatch, Planning and Mapping personnel to be co located
23 and work together as a team to manage emergencies. This centralized
24 process also allowed the development of the Event Management Tool
25 (EMT) system which was implemented in 2018.

26 PG&E started tracking gas flow stop times for Grade 1 leaks in 2018
27 although this has not been a mandatory requirement, except when the
28 incident is California Public Utilities Commission or Department of
29 Transportation reportable.

30 **2. Data Collection Methodology**

31 The EMT is currently used as the official system to track gas
32 emergencies from start to finish. The EMT provides access to latest

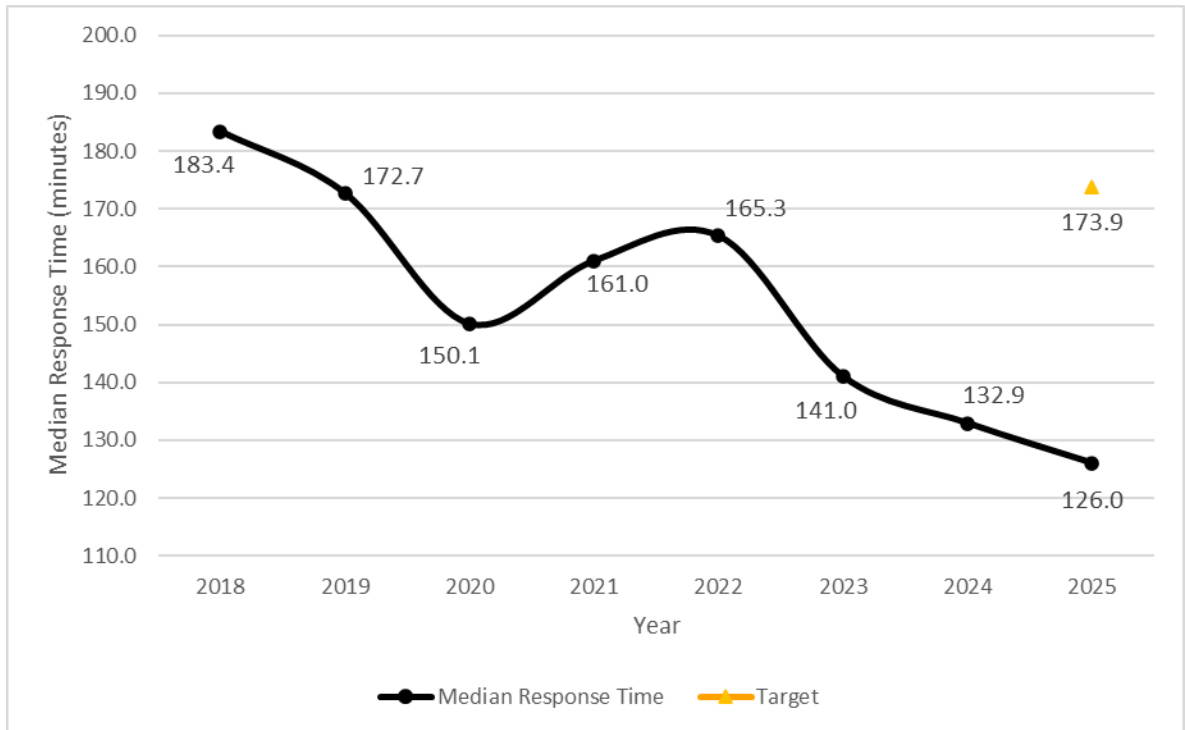
1 information on an incident. All emergency data is consolidated and stored in
2 one place.

3 The EMT is used by Dispatch and Gas Distribution Control Center
4 teams to create emergency events and collect incident information. It also
5 allows us to run reports and retrieve historical information. There are
6 distinct types of incidents recorded in the EMT: explosions, corrosion, cross
7 bore, pipe damage, dig-ins, evacuations, exposed pipe—no gas leak, fires,
8 gas leaks (including Grade 1), high concentration areas, Hi/Lo pressures,
9 material failure, pipe ruptures, vehicle impacts, among others. No
10 transmission events are included in the metric.

11 **3. Metric Performance for Reporting Period**

12 The range of data available to calculate the historical TRHC for Grade 1
13 leaks is from 2018 to 2025. In this timeframe, performance improved
14 significantly, decreasing from 183.4 minutes in 2018 to 126 minutes in 2025.
15 The performance in 2025 represents a 5.2 percent improvement over the
16 performance of 132.9 minutes in 2024. This improvement is due to
17 strategically prearranging construction crews in locations with high
18 frequency of Grade 1 leaks after business hours and weekends,
19 understanding root causes for long shut-in time incidents, sharing best
20 practices system wide during weekly performance review calls, and
21 improved partnership between Field Service and Maintenance and
22 Construction (M&C) organizations.

**FIGURE 4.7-1
TIME TO RESOLVE HAZARDOUS CONDITIONS MEDIAN RESPONSE TIME
2018-2025**



1 **C. (4.7) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 The 2026 target is set as the average of the annual median times the
 4 past 8-years (2018-2025) + 10 percent. The 2030 target is to remain flat
 5 aligned with 2026 target. Recalculating the 5-yr target annually to include
 6 previous year’s performance allows PG&E to incorporate recent process
 7 improvements as part of the path forward.

8 **2. Target Methodology**

9 To establish the 1-year and 5-year targets, PG&E considered the
 10 following factors:

- 11 • Historical Data and Trends: The 2026 target is based on the average of
 12 the annual medians in the period 2018-2025, plus 10 percent. The
 13 eight-year period is being used to include recent performance. The
 14 eight-year period was used because 2018 is the first year of available
 15 historical data. The use of 10 percent allows for non-significant
 16 variability;

- 1 • Benchmarking: Direct benchmarking data is not available; therefore,
2 was not used in Target Methodology;
- 3 • Regulatory Requirements: No regulatory requirements that pertain to
4 setting Target Methodology;
- 5 • Attainable Within Known Resources/Work Plan: Yes;
- 6 • Appropriate/Sustainable Indicators for Enhanced Oversight and
7 Enforcement: Yes, performance at or below the average of the medians
8 in the 2018-2025 period, plus 10 percent, is a sustainable assumption
9 for maintaining the improvement from 2018-2025 time-frame, plus room
10 for non-significant variability and other unknown variables; and
- 11 • Other Qualitative Considerations: This is a new metric to PG&E that
12 has not yet been closely tracked or well understood.

13 3. 2026 Target

14 The 2026 target is to maintain performance at or lower than
15 169.5 minutes based on the factors described above. The 2026 target is the
16 average of the annual median times the past 8-years (2018-2025) +
17 10 percent. This target aligns with our commitment to the safe operations of
18 our assets. This target represents an appropriate indicator light to signal a
19 review of potential performance issues. Target should not be interpreted as
20 intention to worsen performance.

21 4. 2030 Target

22 The 2030 target is to maintain performance at or lower than
23 169.5 minutes based on the factors described above. The 5-year target will
24 remain flat aligned with the 2026 target.

25 D. (4.7) Performance Against Target

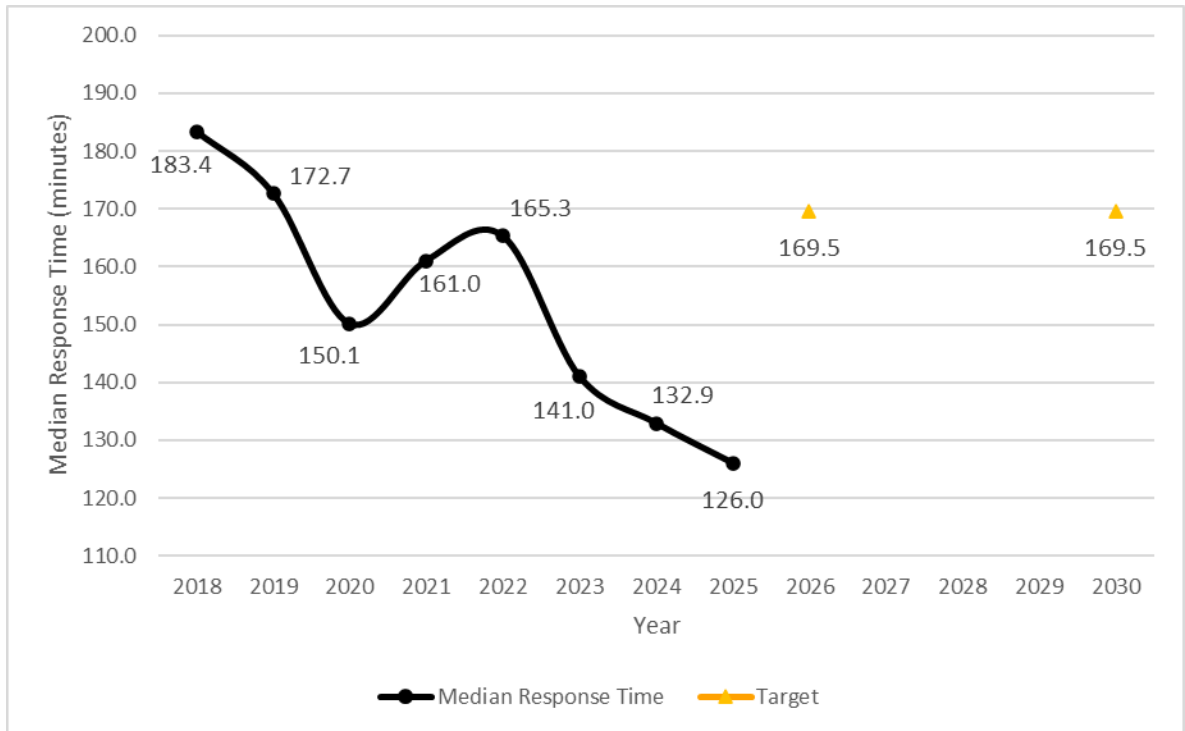
26 1. Maintaining Performance Against the 1-Year Target

27 As demonstrated in Figure 4.7-2, PG&E saw a median response time of
28 126.0 minutes in 2025 which is better than the Company's one-year target.

29 2. Maintaining Performance Against the 5-Year Target

30 As discussed in Section E, PG&E will continue mitigating the risk of loss
31 of containment on Gas Distribution Mains and Services and employing its
32 various programs to maintain performance in its efforts toward its five-year
33 target.

**FIGURE 4.7-2
TIME TO RESOLVE HAZARDOUS CONDITIONS MEDIAN RESPONSE TIME
2018-2025 AND
TARGETS FROM 2026 AND 2030**



E. (4.7) Current and Planned Work Activities

Starting in 2022, PG&E is applying the definition as stated in Decision 21-11-009 to existing data for further visibility. There are on-going efforts in place to ensure traceable and verifiable data. PG&E plans to implement SAP controls to ensure that Field Service and M&C personnel are capturing this data at each occurrence. This will drive visibility into the metric to allow for performance management. This metric will continue to mitigate the risk of loss of containment on Gas Distribution Main or Service by reducing distribution pipeline rupture with ignition.

The metric is supported by the following programs which focus on improving public safety: Field Services and Gas M&C.

- Gas Field Service: Field Service responds to gas service requests, which include investigation reports of possible gas leaks, carbon monoxide monitoring, customer requests for starts and stops of gas service, appliance pilot re-lights, appliance safety checks, as well as emergency situations as first responders; and

1 • Gas M&C: Gas M&C performs routine maintenance of PG&E's gas
2 distribution facilities, which includes emergency response due to dig-ins, as
3 well as leak repairs.

4 The following process improvement initiatives are on-going to help achieve
5 metric results:

- 6 • Daily Operating Reviews to identify deviations from the targets for the
7 previous 24 hours and identify countermeasures for continuous
8 improvement;
- 9 • Weekly Operating Review meetings to share best practices and review long
10 duration events;
- 11 • Provide yearly plastic squeeze training for all Field Service employees as
12 part of Operator Qualification refresher;
- 13 • Live action drills to simulate emergency scenarios, practicing isolation
14 procedures and documenting lessons learned; and
- 15 • [Pre-arranging crews on weekends to improve overall response time to](#)
16 [emergencies.](#)

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 5.1
CLEAN ENERGY GOALS COMPLIANCE METRIC

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
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CLEAN ENERGY GOALS COMPLIANCE METRIC

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 5.1**
4 **CLEAN ENERGY GOALS COMPLIANCE METRIC**

5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (5.1) Overview**

8 **1. Metric Definition**

9 Safety and Operational Metric 5.1 – Clean Energy Goals Compliance
10 Metric is defined as:

11 *Progress towards Pacific Gas and Electric Company’s (PG&E)*
12 *procurement obligations as adopted in Decision (D.) 21-06-035,*
13 *D.19-11-016 and any subsequent decision(s) in Rulemaking (R.) 20-05-003,*
14 *R.25-06-019, or a successor proceeding, updating these requirements.*

15 **2. Introduction to the Clean Energy Goals Compliance Metric**

16 The Clean Energy Goals Compliance Metric (CEG Metric) directs PG&E
17 to report on its progress towards meeting the procurement obligations in the
18 following California Public Utilities Commission (Commission) decisions:
19 (1) D.19-11-016, (2) D.21-06-035, and (3) D.23-02-040 (together, the
20 Integrated Resource Planning (IRP) Decisions).^{1,2}

21 In November 2019, the Commission issued D.19-11-016 in part to
22 address near-term system reliability concerns beginning in 2021.

23 D.19-11-016 requires incremental procurement of system-level Resource
24 Adequacy (RA) capacity of 3,300 megawatts (MW) by all
25 Commission-jurisdictional Load-Serving Entities (LSE).³ In line with state

1 This report includes data as of December 31, 2025, therefore it does not include the procurement targets from D.26-02-047 for the years 2030 – 2032 which was issued on March 5, 2026. These procurement targets will be added to the September 2026 report.

2 See D.22-02-004 directing PG&E to make progress towards procuring a 95 MW 4-hour energy storage project at the Kern-Lamont substation and a 50 MW 4-hour energy storage project at the Mesa substation, pp. 160-162; Ordering Paragraph (OP) 13 of D.22-02-004 exempts these energy storage projects from the Clean Energy Goals Compliance Metric.

3 D.19-11-016, p. 34.

1 policy goals, the Commission also expressed a preference that LSEs pursue
2 “preferred resources” such as new clean electricity capacity.⁴ Of the
3 3,300 MW procurement order, PG&E is directed to procure 716.9 MW of RA
4 capacity on behalf of its bundled service customers with online dates
5 between the years 2021-2023.⁵

6 D.19-11-016 also allowed each non-investor-owned utility LSE an
7 opportunity to “opt-out” of its procurement obligation and required
8 notification to the Commission in February 2020 to exercise this option. On
9 April 15, 2020, the Commission issued a ruling increasing PG&E’s
10 procurement obligation by 48.2 MW, to an aggregated total of 765.1 MW, to
11 account for LSE opt-outs.⁶ PG&E is required to procure the 765.1 MW with
12 the following online dates: 50 percent (382.6 MW) by August 1, 2021,
13 25 percent (191.3 MW) by August 1, 2022, and 25 percent (191.3 MW) by
14 August 1, 2023.⁷

15 On July 29, 2022, PG&E filed supplemental Advice Letter
16 (AL) 6654-E-A, discussing the fact that three “opt-out” LSEs ceased serving
17 customers in California. As stated in AL 6654-E-A, PG&E consulted with the
18 Commission’s Energy Division, and it was determined that the total opt-out
19 procurement obligation assigned to these three LSEs is 1.2 MW. As set
20 forth in D.22-05-015, in the event of an “LSE bankruptcy, or any other exit
21 from the market,” any associated costs attributable to the opt-out
22 procurement shall be allocated to the traditional cost allocation mechanism.
23 On January 12, 2023, the Commission adopted Resolution (Res.E-5239 and
24 clarified that the 1.2 MW of procurement that PG&E conducted on behalf of
25 opt-out LSEs that subsequently ceased serving customers will continue to
26 count towards PG&E’s procurement obligation under D.19-11-016.⁸

4 D.19-11-016, Conclusion of Law (COL) 22.

5 D.19-11-016, OP 3.

6 See Administrative Law Judge’s Ruling Finalizing Load Forecasts and greenhouse gas (GHG) Benchmarks for Individual 2020 IRP Filings and Assigning Procurement Obligations Pursuant to D.19-11-016, issued on April 15, 2020, p. 11.

7 Due to rounding, numbers presented throughout this chapter may not add up precisely to the totals provided.

8 Res.E-5239, p. 11.

1 In June 2021, the Commission issued D.21-06-035 to address the
2 mid-term (period of 2023-2026) reliability needs of the electric grid and to
3 help achieve the state’s GHG emissions reduction targets. In the decision,
4 the Commission ordered 11,500 MW of incremental resource procurement
5 exclusively from zero-emitting resources, unless the resource otherwise
6 qualifies under California’s Renewables Portfolio Standard eligibility
7 requirements.⁹ Of this total, PG&E is required to procure 2,302 MW with the
8 following online dates: 400 MW by August 1, 2023; 1,201 MW by June 1,
9 2024; 300 MW by June 1, 2025; and 400 MW by June 1, 2026. In addition,
10 D.21-06-035 also required that 900 MW (of PG&E’s 2,302 MW) have
11 specific operational characteristics to spur the development of long-duration
12 energy storage, increase the availability of firm clean energy, and serve as a
13 replacement source of clean energy for the retiring Diablo Canyon Power
14 Plant.¹⁰

15 In February 2023, the Commission issued D.23-02-040 which requires
16 incremental procurement of system-level capacity of 4,000 MW by all LSEs
17 to address projected increases in electric demand, increasing impacts of
18 climate change, the likelihood of additional retirements of fossil-fueled
19 generation, and the likelihood that delays beyond 2026 of long-duration
20 energy storage and firm clean energy (collectively, long lead-time (LLT)
21 resources) required under D.21-06-035 will be necessary. Of this total,
22 PG&E is required to procure 777 MW with the following online dates: 388
23 MW by June 1, 2026; and 388 MW by June 1, 2027. The decision also
24 revised the online dates of LLT resources from June 1, 2026, to June 1,
25 2028, for all Commission-jurisdictional LSEs.

26 In aggregate, to date, the total amount of PG&E’s procurement ordered
27 under the IRP Decisions is 3,844.1 MW with online dates between
28 2021-2028. Table 1 outlines PG&E’s procurement obligation for each year.

⁹ D.21-06-035, OP 1.

¹⁰ *Id.*, pp. 35-36; See also D.21-06-035, p. 56 requiring PG&E to procure 500 MW of zero-emitting resources by June 1, 2025, and 400 MW of LLT resources by June 1, 2026.

**TABLE 5.1-1
PG&E'S TOTAL PROCUREMENT OBLIGATION PURSUANT TO THE IRP DECISIONS
(PRESENTED AS MW OF NET QUALIFYING CAPACITY (NQC))**

Line No.	Online Date	D.19-11-016	D.21-06-035	D.23-02-040	Total
1	8/1/2021	382.6			382.6
2	8/1/2022	191.3			191.3
3	8/1/2023	191.3	400		591.3
4	6/1/2024		1,201		1,201
5	6/1/2025		300		300
6	6/1/2026			388	388
7	6/1/2027			388	388
8	6/1/2028		400		400
9	Total	765.1	2,302	777	3,844.1

On March 5, 2026, the Commission adopted D.26-02-057 as part of R.25-06-019 directing LSEs to procure 2,000 MW of NQC by 2030, 2,000 MW of NQC by 2031, and 2,000 MW of NQC by 2032, with at least one quarter required to come from resources that have a capacity factor of at least 80 percent and/or long-duration storage. PG&E has a share of incremental procurement from this order and it will be incorporated into this metric in future reports. It is not incorporated now because this report covers data through 2025, before the new procurement order was adopted.

3. Background on Net Qualifying Capacity

For the purpose of assessing whether an LSE's procurement obligation has been met in accordance with the IRP Decisions, the Commission uses capacity counting rules based on the Commission's RA Program and the results of effective load carrying capability (ELCC) modeling by consultants E3 and Astrapé.¹¹ The counting rules are generally expressed as a percentage that is applied to the nameplate capacity of the procured resource. For example, a 4-hour energy storage resource with a nameplate capacity of 100 MW can count 90.7 MW towards an LSE's 2024 requirement (100 MW * 90.7 percent ELCC = 90.7 MW of NQC). PG&E's procurement

¹¹ See D.21-06-035, p. 71 and D.23-02-040, pp. 28-29.

1 progress in this report is presented as MW of NQC based on the applicable
2 counting rules and guidance provided by the Commission.¹²

3 **B. (5.1) Metric Performance**

4 **1. Historical Data**

5 Pursuant to the IRP Decisions, resource procurement obligations and
6 compliance milestones began in 2021. The projects pertaining to PG&E's
7 resource procurement obligations and compliance milestone date
8 requirements of August 1, 2021, August 1, 2022, and August 1, 2023 have
9 all achieved commercial operation.

10 Starting in 2024, the compliance milestone date for resources to be
11 online by was set to June 1 per D.21-06-035. [For the procurement](#)
12 [milestone of June 1, 2024, PG&E had originally procured more than its](#)
13 [2,366.1 MW of NQC obligations.](#) However, project development delays
14 resulted in PG&E being unable to meet the June 1, 2024 compliance
15 milestone date by 33.3 MW of NQC. As of the release of this report, all but
16 two projects that were contracted to be online by June 1, 2024 are online.
17 [These two projects were also not online by the 2025 compliance milestone,](#)
18 [June 1, 2025.](#)

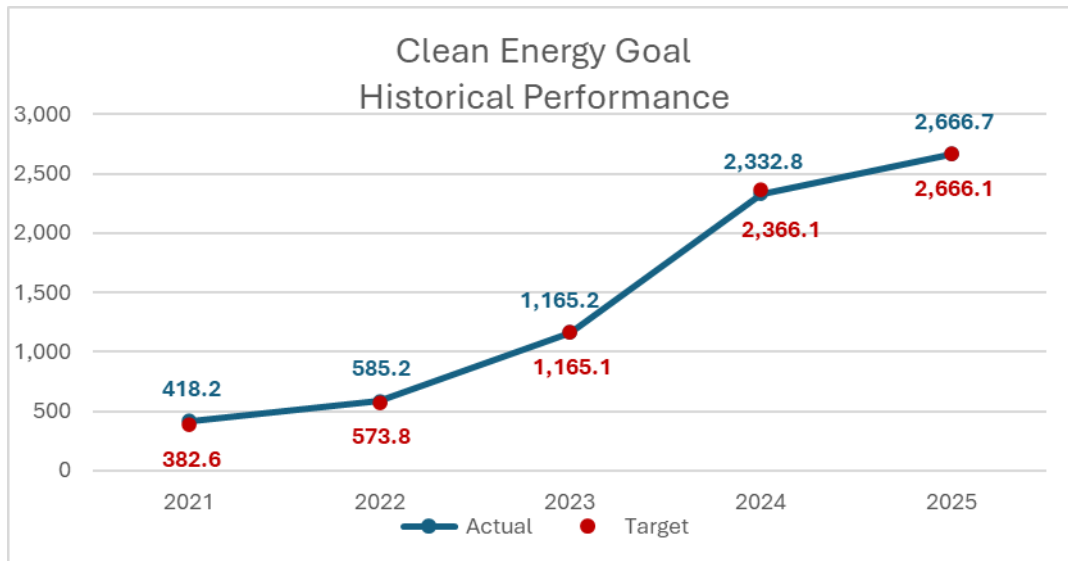
19 [For the procurement milestone of June 1, 2025, PG&E had originally](#)
20 [procured more than its 2,666.1 MW of NQC obligations.](#) However, project
21 [development delays resulted in some of these projects not coming online by](#)
22 [June 1, 2025.](#) As a result, under then-existing decisions, PG&E procured
23 [bridge imports to meet its 2025 target of 2,666.1 MW of NQC.](#)

¹² See the Incremental ELCC Study for Mid-Term Reliability Procurement (January 2023 Update), p. 10 at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20230210_irp_e3_astrape_updated_incremental_elcc_study.pdf; See also the Staff Memo on Incremental ELCC to be Used for Mid-Term Reliability Procurement (D.21-06-035) at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-02-irp_mtr_elccs-public_transmittal_memo_v1.pdf.

**TABLE 5.1-2
PG&E'S HISTORICAL METRIC PERFORMANCE (MW OF NQC)**

Line No.	Online Date	Total Procurement Obligation	Actual Procured Capacity
1	8/1/2021	382.6	418.2
2	8/1/2022	573.8	585.2
3	8/1/2023	1,165.1	1,165.2
4	6/1/2024	2,366.1	2,332.8
5	6/1/2025	2,666.1	2,666.7

**FIGURE 5.1-1
PG&E'S HISTORICAL METRIC PERFORMANCE (MW OF NQC)**



1 PG&E relies upon three main sources of available data to monitor its
 2 procurement progress toward the IRP Decisions: (1) the baseline list of
 3 resources used to establish the procurement targets, (2) Commission rules
 4 and guidance on determining the MW of NQC, and (3) PG&E's internal
 5 database containing all of its energy procurement contracts approved by the
 6 Commission.

7 1) Baseline List of Resources: In establishing the procurement targets in
 8 the IRP Decisions, the Commission established baseline assumptions of
 9 resources available to meet system reliability needs. LSEs must
 10 demonstrate that the MW of NQC of the procured resource, new and/or

1 existing, are incremental to the Commission's baseline assumptions.¹³
2 PG&E uses this information to ensure resources are eligible to count
3 towards its procurement obligations.

4 2) Commission Rules and Guidance on MW of NQC: As described above,
5 the amount of MW of NQC that can be used to count towards an LSE's
6 procurement obligation is based on the Commission's rules and
7 guidance. PG&E uses this information to determine the amount of MW
8 of NQC that is eligible to count towards its procurement obligations.

9 3) PG&E's Internal Database: This database contains PG&E's energy
10 procurement contracts approved by the Commission, including
11 procurement contracts to meet PG&E's procurement obligations under
12 the IRP Decisions. The data contained in this database is consistent
13 with the procurement contracts and respective ALs filed for Commission
14 approval.

15 **2. Data Collection Methodology**

16 As described above, PG&E uses the baseline list of resources and the
17 Commission's rules and guidance on MW of NQC to monitor its
18 procurement progress.¹⁴

19 **3. Metric Performance for Reporting Period**

20 PG&E procured sufficient incremental MW of NQC to meet and exceed
21 its procurement obligations for incremental capacity with online dates in
22 [2025](#) pursuant to D.19-11-016 and D.21-06-035.¹⁵ However, due to project
23 development delays, as further explained in section D.1, when possible
24 PG&E procured bridge resources to replace delayed resources on a monthly
25 basis beyond the [June 1, 2025 online obligation date until the issuance of](#)

¹³ See the Commission's baseline assumptions at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20200103_procurement_baseline_list.xlsx (D.19-11-016) and https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/d2106035_baseline_gen_list_20220902.xlsx (D.21-06-035).

¹⁴ See the information maintained by the Commission at: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track>.

¹⁵ PG&E's ALs 5826-E, 6033-E, 6289-E, and 6477-E.

1 D.25-09-007, which eliminated the use of bridge resources for alternative
2 compliance.

3 PG&E notes that the Commission stated that procurement:

4 ...amounts [that] are in excess of [an] LSE's obligation under
5 D.19-11-016...may be counted toward the capacity requirements [in
6 D.21-06-035] if they otherwise qualify.¹⁶

7 Moreover, D.21-06-035 stated that the Commission:

8 ...will allow LSEs to show procurement that they have conducted to
9 support the Commission's orders or requirements in the context of the
10 RPS program, as well as for emergency reliability purposes in
11 R.20-11-003, as compliance toward the requirements herein.¹⁷

12 Accordingly, PG&E estimates that approximately 262 MW of NQC of its
13 procurement toward the procurement for both D.19-11-016 and R.20-11-003
14 that have been approved by the Commission, and that are in excess of what
15 is required by each of those decisions, may be applied towards its
16 procurement obligations under D.21-06-035.¹⁸

17 On January 21, 2022, PG&E filed AL 6477-E requesting Commission
18 approval of nine agreements resulting from PG&E's Mid-Term Reliability
19 Phase 1 solicitation to meet its procurement obligations under D.21-06-035.
20 These agreements total 1,434 MW of NQC and have been approved by the
21 Commission.¹⁹ Subsequently, the projects associated with these nine
22 agreements were affected by unprecedented market upheavals which
23 diminished their economic and commercial viability.²⁰ This unexpected
24 market challenge posed a risk of project failures for all LSEs in the market
25 procuring resources toward the IRP Decisions, including PG&E. As a result,
26 to maintain the commercial viability of the projects, PG&E negotiated
27 amendments for four of the nine projects. Amendments were presented to

¹⁶ D.21-06-035, p. 80.

¹⁷ *Id.*

¹⁸ PG&E's AL 6289-E.

¹⁹ On April 21, 2022, the Commission adopted Res.E-5202 approving the nine agreements without modification as filed in PG&E's AL 6477-E.

²⁰ For example, on July 20, 2022, PG&E filed AL 6658-E, requesting approval of contract amendments for the AMCOR and the North Central Valley projects after each developer described external barriers to completing their projects in line with their existing contract obligations.

1 the Commission for approval on September 23, 2022. The Commission
2 approved these amendments on December 1, 2022.²¹

3 On January 13, 2023, PG&E filed AL 6825-E, on February 14, 2023,
4 PG&E filed AL 6861-E, and on September 13, 2023, PG&E filed AL 7022-E,
5 requesting Commission approval of four additional agreements resulting
6 from PG&E's Mid-Term Reliability Phase 2 solicitation to further meet its
7 procurement obligations under D.21-06-035. These agreements have been
8 approved by the Commission.²²

9 Despite the significant unprecedented market challenges PG&E has
10 made steady progress towards achieving its procurement obligations under
11 D.21-06-035.

12 As stated above, D.21-06-035 requires that 900 MW of NQC (of PG&E's
13 2,302 MW of NQC) have specific operational characteristics. Specifically,
14 PG&E is directed to procure 500 MW of NQC of firm zero-emitting resources
15 with online dates by June 1, 2025, and 400 MW of NQC of LLT resources
16 with online dates by June 1, 2028.²³ PG&E issued its Mid-Term Reliability
17 Phase 3 solicitation on February 7, 2023 to solicit additional resources
18 toward fulfilling all of its procurement obligations under D.21-06-035,
19 including, the 900 MW of NQC with specific operational characteristics.

20 On February 27, 2024, PG&E filed AL 7177-E, and on September 9,
21 2024, PG&E filed AL 7356-E, requesting Commission approval of
22 five agreements resulting from PG&E's Mid-Term Reliability Phase 3
23 solicitation. [Additionally, on June 18, 2024, PG&E filed AL 7299-E and on](#)
24 [November 4, 2024, PG&E filed AL 7420-E requesting approval of four](#)
25 [agreements from the Mid-Term Reliability Phase 3 solicitation. The last AL](#)
26 [resulting from PG&E's Mid-Term Reliability Phase 3 solicitation was](#)

21 PG&E's AL 6711-E.

22 On April 27, 2023, the Commission adopted Res.E-5262 and Res.E-5263 approving PG&E's AL 6825-E and AL 6861-E. On January 11, 2024, the Commission adopted Res.E-5297 approving AL 7022-E.

23 The LLT resources are comprised of: (1) firm zero-emitting generation with a capacity factor of at least 80 percent and (2) long-duration storage resources defined as having at least eight hours of duration.

1 AL 7602 which requested approval of one agreement. All of these
2 agreements have been approved by the Commission.²⁴

3 PG&E also issued a Long Lead Time solicitation on October 15, 2024,
4 to purchase 200 MW of long duration energy storage projects and 200 MW
5 of firm zero-emitting projects, as directed by D.21-06-035. On July 16,
6 2025, PG&E filed AL 7648-E requesting Commission approval of one
7 agreement with a long duration energy storage resource resulting from this
8 solicitation and it has been approved by the Commission.²⁵

9 C. (5.1) 1-Year Target and 5-Year Target

10 1. Updates to 1-Year Target and 5-Year Target Since Last Report

11 The 1-year target has been updated to reflect PG&E's required
12 procurement for 2026 under the IRP Decisions which is to procure
13 3,054.1 MW of cumulative NQC by June 1, 2026, as outlined in Table 5.1-1.
14 The 5-year target has also been updated to reflect PG&E's additional
15 procurement requirements, as outlined in Commission decision—
16 D.23-02-040—issued in February 2023.²⁶ As summarized in Table 5.1-1,
17 the 5-year target for 2030 remains the same as the 2028 target, which is to
18 procure 3,844.1 MW of cumulative NQC by June 1, 2028. However, on
19 May 30, 2025, PG&E filed AL 7608-E to request an extension to the online
20 date requirement for the LLT resources pursuant to D.24-02-047 OP 16(b).
21 The Commission granted the extension.²⁷ The extension, when coupled
22 with adherence with D.25-09-007 (described below), has moved PG&E's
23 requirement for the procurement of LLT resources from June 1, 2028, until
24 June 1, 2031.

²⁴ On June 4, 2024, the Commission adopted Res.E-5325 approving PG&E's AL 7177-E, on February 20, 2025, the Commission adopted Res.E-5370 approving PG&E's AL 7356-E, on April 7, 2025 the Commission adopted Res.E-5345 approving PG&E's AL-7299, on April 24, 2025, the Commission adopted Res.E-5377 approving PG&E's AL-7420, and on August 18, 2025, the Commission adopted Res.E-5409 approving PG&E's AL 7602.

²⁵ On January 21, 2026, the Commission adopted Res.E-5437 approving PG&E's AL 7648-E.

²⁶ D.23-02-040, p. 31.

²⁷ On January 22, 2026, the Commission issued a Disposition Letter approving the Tier 2 AL-7608.

2. Target Methodology

To establish the 1-year and 5-year targets, PG&E considered the following factors:

- Historical Data and Trends: Not Applicable;
- Benchmarking: Not applicable;
- Regulatory Requirements: The targets are set to match the cumulative procurement obligations set forth in the IRP Decisions;
- Attainable Within Known Resources/Work Plan: Yes;
- Appropriate/Sustainable Indicators for Enhanced Oversight and Enforcement: Yes;
- Other Considerations:
 - The target approach was established to meet the Commission’s current procurement obligations. PG&E’s procurement obligation may increase if other LSEs fail to meet their procurement obligations and PG&E is ordered by the Commission to make back-stop procurement on their behalf;²⁸ and
 - The ability for procured capacity to actually come online by established contractual online dates can be impacted by external factors, as has occurred recently due to impacts of the COVID-19 pandemic, significant and unprecedented market challenges, supply chain disruptions and the Department of Commerce’s investigation into potential solar module tariff circumvention.²⁹

3. 2026 Target

The 1-year target for the CEG Metric is to procure 3,054.1 MW of cumulative NQC with an online date by June 1, 2026, which is equal to the cumulative procurement obligations for 2021, 2022, 2023, 2024, 2025, and 2026 as outlined in Table 5.1-1.

²⁸ D.19-11-016, p. 67.

²⁹ Erne, David, Mark Kootstra. 2023. Final Draft Diablo Canyon Nuclear Power Plant Extension – CEC Analysis of Need to Support Reliability. California Energy Commission. Publication Number: CEC-200-2023-004.

1 **4. 2030 Target**

2 The IRP Decisions do not have a 2030 obligation to align with a new
3 5-year target for the CEG Metric. Therefore, the current target remains to
4 procure 3,844.1 MW of cumulative NQC with an online date by June 1,
5 2028, which is equal to the cumulative procurement obligations for
6 2021-2028 as outlined in Table 5.1-1. However, given market and
7 development challenges to procuring capacity from resources qualified to
8 meet the 2028 obligations as the IRP Decisions require, PG&E requested an
9 extension via AL 7608-E on May 30, 2025, which the Commission approved
10 on January 22, 2026. As a result, 400 MW of the LLT resource subcategory
11 are allowed to come online by 2031 instead of 2028, consistent with
12 D.25-09-007 (described below). However, because PG&E's interpretation of
13 D.25-09-007 is that the same capacity of long-term generic resources still
14 need to be procured to be online in in 2028, the overall 2028 and thus the
15 overall 2030 target would remain at 3,844.1 MW.

16 **D. (5.1) Performance Against Target**

17 **1. Progress Towards the 1-Year Target**

18 PG&E has encountered challenges with executing contracts for
19 sufficient incremental capacity with online dates on or before June 1, 2026
20 and plans to utilize the alternative compliance mechanisms as allowed by
21 the IRP Decisions and D.25-09-007 to meet the 1-year target.

22 **2. Progress Towards the 5-Year Target**

23 PG&E continues to make progress towards meeting the 5-year target.
24 Within this overall procurement target, PG&E has a requirement to procure
25 900 MW of NQC with specific operational characteristics and the
26 Commission decision for supplemental mid-term procurement as outlined
27 above. In September 2023, PG&E filed for approval of one contract that is
28 expected to count towards the operational characteristics as a zero-emitting
29 resource.³⁰ Additionally, in June 2024, PG&E filed for approval of two
30 renewable generation contracts which are expected to be contractually

³⁰ On January 12, 2024, the Commission adopted Res.E-5297 approving AL 7022-E.

1 paired with an energy storage resource to cunct towards the operational
2 characteristics as a zero-emitting resource.³¹

3 PG&E reiterates, and as outlined above, that developers and LSEs have
4 experienced significant, unprecedented market challenges, increases in
5 component prices, continued supply chain constraints, and industry-wide
6 inflation on total project costs that have hindered the ability for developers to
7 bring projects online by their contractual online dates.³² In recognition of
8 these challenges, the Commission provided compliance flexibility in
9 D.23-02-040, D.24-02-047, and D.24-09-006 for LSEs to continue making
10 progress towards their procurement obligations to ensure system reliability
11 in the mid-term. Compliance flexibility has included extending the online
12 date of LLT resources from 2026 to 2028, allowing LSEs to request for a
13 further extension for LLT resources until 2031 based on cost considerations
14 or projects with later online dates, allowing the use of bridge resources for a
15 period of time³³and, in some cases, re-contracting with resources that are
16 retiring or have expiring or expired contracts.³⁴

17 On September 18, 2025, the Commission approved D.25-09-007, which
18 granted, with modifications, Southern California Edison Company's Petition
19 for Modification of D.23-02-040 and D.24-02-047 filed on March 21, 2025.
20 D.25-09-007 eliminated the option for LSEs to use bridge contracts as an
21 alternative compliance mechanism going forward, given the high cost and
22 lack of short-term reliability benefits such bridge contracts provide, and
23 established that LSEs will be deemed compliant with their D.21-06-035 and
24 D.23-02-040 obligations (as modified by D.24-02-047) if they can show that:
25 (1) they have sufficient executed long-term (ten years or more) contracts (for
26 capacity and/or energy, as applicable) to meet the applicable procurement
27 obligation; and (2) they have met their month-ahead system RA obligations

31 [On April 7, 2025, the Commission adopted Res.E-5345 approving AL 7299-E.](#)

32 Erne, David, Mark Kootstra. 2023. Final Draft Diablo Canyon Nuclear Power Plant Extension – CEC Analysis of Need to Support Reliability. California Energy Commission. Publication Number: CEC-200-2023-004.

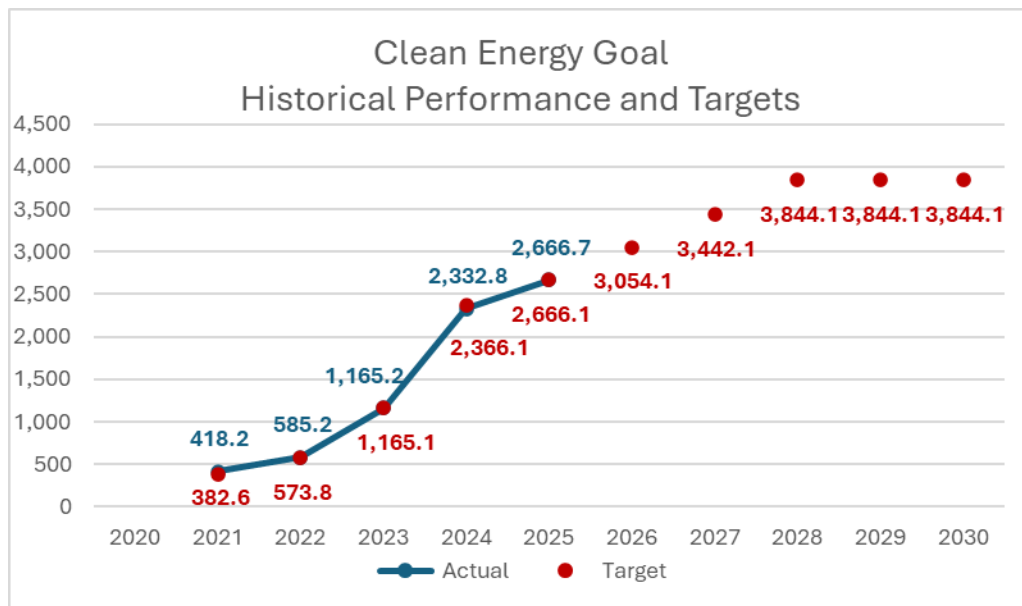
33 [Bridge resources have been eliminated as an alternative compliance mechanism as of the approval of D.25-09-007 on September 18, 2025.](#)

34 D.23-02-040, COLs 7 and 12. D.24-02-047, OPs 16 and 19. D.24-09-006, OP 1.

for all months in which their procurement is delayed, by the final deadline for curing any RA deficiency. D.25-09-007 also provided an alternative compliance pathway for LLT resources, which allows LSEs to delay procurement of LLT resources to June 1, 2031 if LSEs procure long-term contracts that otherwise meet the requirements of the IRP Decisions by June 1, 2028.

PG&E will continue to work with developers and the Commission to address the challenges noted above in order to meet the current 5-year target, and any additional procurement requirements in support of the state’s reliability needs.

**FIGURE 5.1-2
PG&E’S CLEAN ENERGY GOAL HISTORICAL PERFORMANCE AND TARGETS (MW OF NQC)**



E. (5.1) Current and Planned Work Activities

Below is a summary description of the key activities that are tied to performance and their description of that tie.

- Solicitations: As noted above, PG&E launched its Mid-Term Reliability Phase 2 and Phase 3 solicitations in April 2022 and February 2023, respectively, seeking to satisfy its remaining procurement obligations under the IRP Decisions, specifically to procure 500 MW of NQC of zero-emitting resources by June 1, 2025, and 400 MW of NQC of long lead time

1 resources by June 1, 2028. PG&E issued an additional Long Lead Time
2 solicitation on October 15, 2024;

- 3 • Supplemental Procurement Order: As described earlier, on February 23,
4 2023, the Commission issued D.23-02-040 increasing PG&E's procurement
5 requirements through 2028. Accordingly, PG&E has incorporated the
6 supplemental procurements order by this decision into its current and
7 planned work activities;
- 8 • Procurement to Mitigate Delayed Resources: PG&E will pursue permitted
9 long-term resources as compliance alternatives to cure procurement gaps
10 where resources are delayed, as authorized by the IRP; and
- 11 • Deemed Compliance: Where applicable, PG&E will seek to demonstrate
12 deemed compliance, as authorized by D.25-09-007.

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 6.1
QUALITY OF SERVICE

PACIFIC GAS AND ELECTRIC COMPANY
SAFETY AND OPERATIONAL METRICS REPORT:
CHAPTER 6.1
QUALITY OF SERVICE

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1 **PACIFIC GAS AND ELECTRIC COMPANY**
2 **SAFETY AND OPERATIONAL METRICS REPORT:**
3 **CHAPTER 6.1**
4 **QUALITY OF SERVICE**

5 The material updates to this chapter since the September 30, 2025 report are
6 identified in blue font.

7 **A. (6.1) Overview**

8 Safety and Operational Metric (SOM) 6.1 – The Quality of Service Metric
9 which is defined as:

10 *The Average Speed of Answer (ASA) for Emergencies metric is a safety*
11 *measure related to multiple risks, as well as quality of service and management*
12 *measure, and is defined as follows: ASA in seconds for Emergency calls*
13 *handled in Contact Center Operations (CCO).¹*

14 **1. Introduction of Metric**

15 A call is classified as an emergency when a caller selects the option of
16 an emergency or hazard situation through the Interactive Voice Response
17 (IVR) system. Once this option is selected the call is routed to an agent to
18 receive the highest priority attention possible.

19 Not only is Emergency ASA a quality measurement of how efficiently we
20 are able to answer customers calling us to report an emergency, but it is
21 also a safety measurement. Answering the call is the first step ensuring the
22 customer is safe.

23 The metric is calculated by determining the average amount of time it
24 took to connect customers to a service representative for calls where the
25 customer identifies via IVR that they are calling to report a hazardous or
26 emergency situation, such as a suspected natural gas leak or downed
27 power line.

28 **2. Background**

29 On an annual basis, Pacific Gas and Electric Company (PG&E or the
30 Company) handles between 5 to 6 million customer calls. Between 2017
31 and 2021, emergency-related calls averaged nine percent of total call

1 Decision 21-11-019, Appendix A, p. 12.

1 volume; however, in the 2020 and 2021 years, emergencies calls have
2 increased due to weather-related storms events, rotating outages, Public
3 Safety Shutoffs (PSPS), and Enhanced Power Safety Settings (EPSS). In
4 2020 and 2021 emergency calls handled were 10 percent and 11 percent of
5 total call volume, respectively.

6 Historically, PG&E has been able to successfully manage staffing needs
7 to ensure emergency calls are answered quickly. The metric and
8 associated targets are designed to maintain our performance.

9 **B. (6.1) Metric Performance**

10 **1. Historical Data (2015 – 2025)**

11 PG&E has 11 years of historical data, representing 2015 – 2025, to
12 include the total emergency calls handled and ASA by month.

13 The historical data for this metric provided with this report provides total
14 emergency calls handled and the ASA performance by month and year.

15 **2. Data Collection Methodology**

16 The performance data is gathered from PG&E's telephony system,
17 Cisco Unified Contact Center Enterprise (UCCE). The data includes the
18 number of emergency calls handled and the total wait times (in seconds).
19 Data is compiled each day for daily, weekly, monthly, and yearly reporting.

20 Historical data is collected using Microsoft's Management Studio
21 application via a Structured Query Language server owned by the
22 Workforce Management Reporting team.

23 The data is gathered by extracting summarized data for emergency
24 specific call types. The call types are created by the Workforce
25 Management Routing Team, to categorize the types of calls that are
26 entering the phone system, Cisco UCCE.

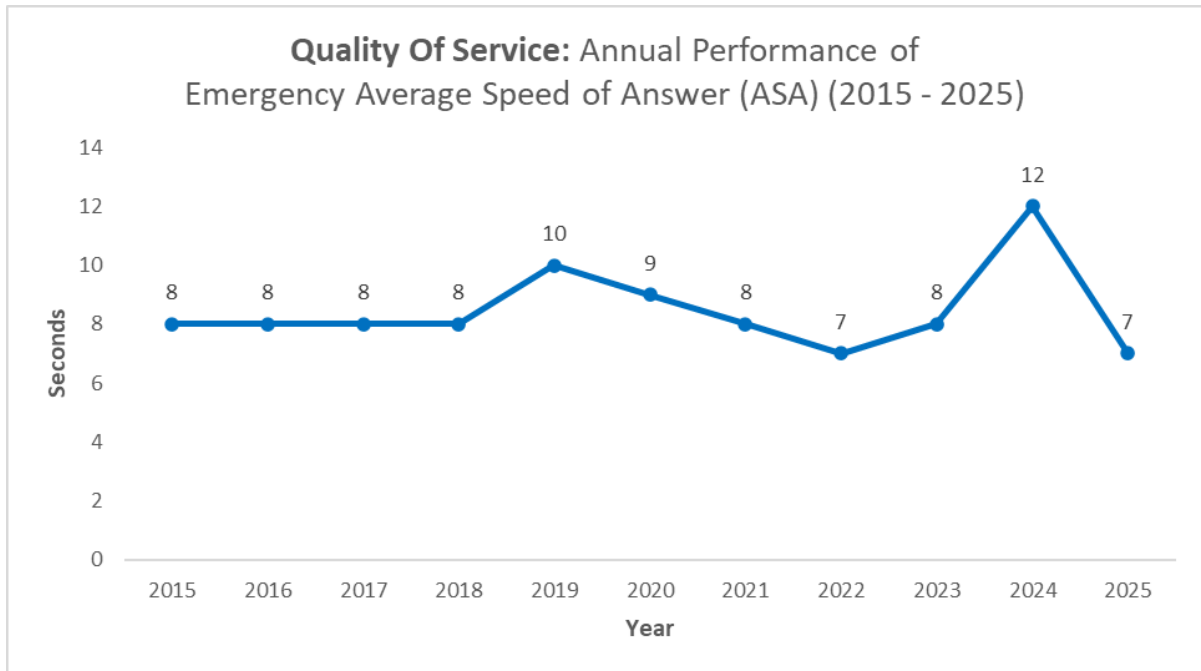
27 PG&E began archiving historical call data in 2015 once it was identified
28 that Cisco UCCE system was truncating historical data as it was running out
29 of storage.

30 **3. Metric Performance for Reporting Period**

31 Between 2015 and 2025, the performance of Emergency ASA ranged
32 between five and twelve seconds, with a median performance of

1 eight seconds (see Figure 6.1-1). In 2024, PG&E’s call wait time was
2 highest (12 seconds) due to an atmospheric river in February 2024.

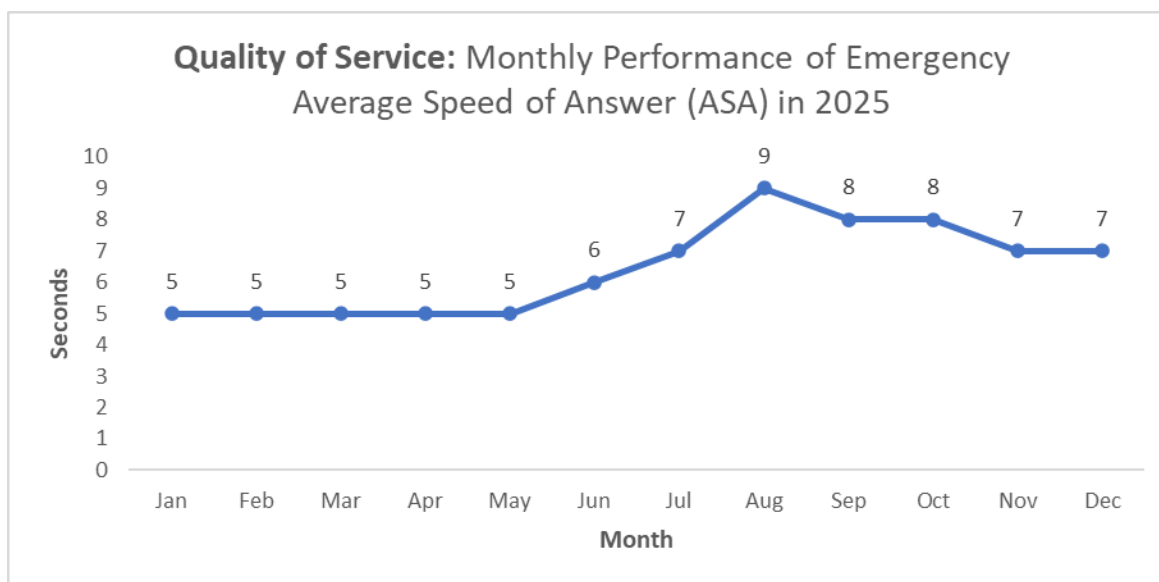
**FIGURE 6.1-1
ANNUAL PERFORMANCE OF EMERGENCY ASA
(2015 – 2025)**



3 In 2025, the Emergency ASA performance was 7 seconds. Over the
4 course of the year, monthly performance metrics fluctuated between five
5 seconds and nine seconds, as illustrated in Figure 6.1-2.

6 Primary drivers to the performance were based on unanticipated
7 incidents (e.g., weather incidents impacting power outages, unplanned
8 power outages) and call center representative staffing availability.

**FIGURE 6.1-2
MONTHLY PERFORMANCE OF EMERGENCY ASA IN 2025**



1 **C. (6.1) 1-Year Target and 5-Year Target**

2 **1. Updates to 1- and 5-Year Targets Since Last Report**

3 There have been no changes to the 1-year and 5-year targets since the
4 last SOMs report filing. The 2025 1-year target is to be at or below
5 15 seconds and the 2029 5-year target is to be at or below 15 seconds.

6 **2. Target Methodology**

7 To establish the 1-year and 5-year targets, PG&E considered the
8 following factors:

- 9 • Historical Data and Trends: The target is based on the average of years
10 2015 to 2019 historical data. These years were utilized as they are
11 most consistent with current operational practices, including the
12 expansion of PSPS, EPSS, and Rotating outage programs. The
13 average of this period is used as a reasonable indicator for sustaining
14 and maintaining the performance going forward;
- 15 • Benchmarking: Not available;
- 16 • Regulatory Requirements: None;
- 17 • Attainable Within Known Resources/Work Plan: Yes, performance at or
18 below the set target is sustainable; and
- 19 • Other Qualitative Considerations: None.

1 **3. 2026 Target**

2 The 2026 target is to be at or below 15 seconds for the year to maintain
3 performance based on the factors described above.

4 **4. 2030 Target**

5 The 2030 target is to be at or below 15 seconds for the year to maintain
6 performance based on the factors described above.

7 **D. (6.1) Performance Against Target**

8 **1. Progress Towards the 1-Year Target**

9 As demonstrated in Figure 6.1-1 above, PG&E's 2025 performance was
10 7 seconds, within the Company's 1-year target.

11 **2. Progress Towards the 5-Year Target**

12 As discussed in Section E below, PG&E has implemented a number of
13 processes to maintain longer-term performance of this metric to meet the
14 Company's 5-year target.

15 **E. (6.1) Current and Planned Work Activities**

16 The performance of this metric is significantly driven by Contact Center
17 Representative resourcing. The CCO are staffed to handle forecasted volume
18 based on historical trends. As staffing needs change due to upcoming events
19 (e.g., PSPS, weather impacts, storm, or heat-related outages) overtime is
20 offered and planned in advance to increase staffing needs. Mandatory overtime
21 (employees are required to stay on shift) and Emergency overtime (PG&E's
22 Workforce Management team will send out notifications to offer Emergency
23 overtime to employees currently not on shift) are available options during
24 same-day operations to support additional staffing needs. PG&E is forecasting
25 to maintain the current level of staffing for 2025-2029.

26 Additionally, providing customers upfront messages of extended wait times
27 via IVR can be used to set expectations and advise customers to call back
28 unless there is an emergency.