PG&E

INDEPENDENT SAFETY MONITOR STATUS UPDATE REPORT

October 31, 2025

FilsingerEnergy.com

LIST OF TERMS AND ACRONYMS

Term/ Acronym	Meaning
ADMS	Advanced Distribution Management System
AFA	Asset Failure Analysis
AHJ	Authority Having Jurisdiction
AHPC	Asset Health & Performance Center
AMI	Advanced Meter Infrastructure
AMLD	Advanced Mobile Leak Detection
AMP	Asset Management Plan
ANSI	American National Standards Institute
AOC	Areas of Concern
ATS	Applied Technology Services
BCMA	Board Certified Master Arborist
BMP	Best Management Practices
C&P	Compression & Processing
CA	Corrective Action
CAIDI	Customer Average Interruption Duration Index
CAL FIRE	California Department of Forestry and Fire Protection
CAP	Corrective Action Plan
CBA	Cost-Benefit Analysis
CCR	California Code of Regulations
CEO	Chief Executive Officer
CESO	Customers Experiencing Sustained Outage
CIRT	Centralized Inspection Review Team
CIS	Close Interval Survey
CM	Continuous Monitoring
CMC	Continuous Monitoring Center
CMD	Circuit Mile Days
CME	Customer Minutes Enabled
COE	Critical Operating Equipment
CoF	Consequence of Failure
COO	Chief Operations Officer
CP	Cathodic Protection
CPI	Comprehensive Pole Inspection
CPUC	California Public Utilities Commission
CPZ	Circuit Protection Zones
CRO	Chief Risk Officer
DAR	Data Asset Registry

Term/ Acronym	Meaning
DCD	Downed Conductor Detection
DFA	Distribution Fault Anticipation
DIMP	Distribution Integrity Management Program
DiRT	Dig-in Reduction Team
DMS	Distribution Mains and Services
DVMP	Distribution Vegetation Management Procedures
E-Fuse	Expulsion Fuse Cutout
EC-Tag	Electric Corrective Tag
EDAPT	Electric Distribution Analysis & Prediction Tool
EDGIS	Extended Dynamic Geographic Information System
EFD	Early Fault Detection
EIA	Enhanced Ignition Analysis
EORM	Enterprise and Operational Risk Management
EPSS	Enhanced Powerline Safety Settings
ETS	Electrical Test Stations
EVM	Enhanced Vegetation Management
FEP	Filsinger Energy Partners
FIMP	Facilities Integrity Management Program
FLISR	Fault Location, Isolation, and Service Restoration
FPI	Fire Potential Index
FTI	Focused Tree Inspections
FSR	Field Safety Reassessment
GDAT	Grid Data Analytics
GIS	Geographic Information System
GO	General Order
HFRA	High Fire Risk Area
HFTD	High Fire Threat District
HID	High Impedance Detection
ICCP	Impressed Current Cathodic Protection
IGP	Integrated Grid Plan
ILI	In-Line Inspection
IMT	Incident Management Team
IRS	Inspection Review Specialist
IPUTD	Integrated Planning Underground Tool Development
ISA	International Society of Arboriculture
ISM	Independent Safety Monitor
IT	Information Technology

Term/ Acronym	Meaning
JSSA	Job Site Safety Analyses
LA	Location Awareness
LC	Line Corrective
LFF	Liquid Filled Fuses
LiDAR	Light Detection and Ranging
LOC	Loss of Containment
LOCDM	Loss of Containment on Gas Distribution Mains or Services
LOTO	Lockout/Tagout
LVC	Large Volume Customer
M&C	Measurement & Control
MAT	Maintenance Activity Type
MAOP	Maximum Allowable Operating Pressure
MDR	Minimum Distance Requirements
MPR	Material Problem Report
MTI	Marked Tree Inventory
MVC	Medium Volume Customer
OA	Operability Assessment
OP	Overpressure
OQ	Operator Qualification
ORT	Outage Review Team
ORV	Operational Risk Validation
PACT	Package Consensus Review Team
PG&E	Pacific Gas and Electric
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIIR	Preliminary Ignition Investigation Report
PIMT	Proactive Ignition Mitigation Task Force
PoF	Probability of Failure
POMMS	PG&E's Operational Mesoscale Modeling System
PRC	California Public Resource Code
PSPS	Public Safety Power Shutoff
PTT	Pole Test and Treat
QA	Quality Assurance
QEW	Qualified Electrical Worker
QC	Quality Control
R3+	Fire potential index score of R3 or higher
RCC	Risk and Compliance Committee
RCE	Root Cause Evaluation
RED	Required End Date

Term/ Acronym	Meaning
RFI	Reportable Fire Ignition
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	System, Applications, and Products in Data Processing
SCADA	Supervisory Control and Data Acquisition
SCAR	Safety Condition Assessment Review
SGF	Sensitive Ground Fault
SI	System Inspections (team)
SME	Subject Matter Expert
SMYS	Specified Minimum Yield Strength
SNAP	System Needs Assessment Platform
TAT	Tree Assessment Tool
TCM	Transmission Composite Model
TG	Temporary Generation
TIMP	Transmission Integrity Management Program
TOAM	Transformer Overload Accuracy Model
TRAQ	Tree Risk Assessment Qualification
TRI	Tree Removal Inventory
UTV	Utility Tracked Vehicle
UVM	Utility Vegetation Management
VASA	Vegetation Assets Strategy and Analytics
VM	Vegetation Management
VMI	Vegetation Management Inspector
VMOM	Vegetation Management for Operational Mitigation
VMDIP	Vegetation Management Distribution Inspection Procedure
WBCA	Wildfire Benefit Cost Analysis
WCD	Work Clearance Document
WDRM v4	Wildfire Distribution Risk Model Version 4
WiRE	Wildfire Intelligence Reporting Engine
WMP	Wildfire Mitigation Plan
WMS	Work Management System
WOR	Weekly Operating Review
WRGSC	Wildfire Risk Governance Steering Committee
WTRM v2	Wildfire Transmission Risk Model Version 2
WTRM v2.1	Wildfire Transmission Risk Model Version 2.1

EXECUTIVE SUMMARY

This Independent Safety Monitor (ISM) Report 7 summarizes oversight activities performed between April 1, 2025, and September 30, 2025, in alignment with CPUC Resolution M-4855 and the ISM Contract with Pacific Gas and Electric Company. The ISM continued to monitor selected safety and risk aspects of PG&E's electric and natural gas operations and infrastructure, building on prior reporting periods and incorporating observations from fieldwork, inspections, and data review. The executive summary highlights notable observations from this work, while additional detail, context, and monitoring results are contained in the full report.

ELECTRIC OPERATIONS

The ISM's review of PG&E's electric operations during this reporting period identified notable observations across several focus areas. These include system reliability, ignition activity and investigative findings, deployment of continuous monitoring technologies, and implementation of targeted task forces and programs. Observations also covered issues related to equipment age and replacement planning, backlog reduction initiatives, and vegetation management practices.

Electric Reliability: PG&E's electric reliability has declined over the past decade, with outage duration and frequency increasing from 2015 to 2024 as reliability capital expenditures shifted toward wildfire mitigation and with the introduction of programs such as PSPS and EPSS. During this period, PG&E's SAIDI increased 188%, placing the utility in the fourth quartile among U.S. electric utilities. PG&E has reported updated initiatives aimed at reversing reliability trends, including a 2025 target to reduce SAIDI by 14%. Efforts underway include establishment of a System Performance Reliability and Resilience Strategy group and a Reliability Task Force. Supporting programs include temporary generation, prioritized distribution circuit inspections and repairs, and remediation of abnormal circuit configurations to enable broader use of Fault Location, Isolation, and Service Restoration systems.

Ignition Trends: PG&E continues to report a downward trend in ignitions within HFTD, with counts declining from a peak of 257 in 2018 to 113 in 2023. Ignitions within HFTD represented 12% of all ignitions in the first seven months of 2025. To account for weather variability, PG&E normalizes ignition data using its Fire Potential Index, with R3+ days identified as most correlated with catastrophic fires. Through September 23, PG&E recorded 35 R3+ CPUC Reportable ignitions in 2025, which was below the 45 experienced during the same period in 2024, and which was equal to the prior three-year average. Normalized by system exposure, the rolling 12-month R3+ ignition rate of 1.06 in September 2025 compared favorably with 3.23 in 2017, but was slightly higher than 2022 and 2023 levels, and below the 1.41 observed at the end of 2024.

Continuous Monitoring Program: PG&E expanded deployment of its Continuous Monitoring technologies during the current reporting period, including Gridscope, Early Fault Detection, Distribution Fault Anticipation, line sensors, and Smart Meters, with integration overseen by the Asset Health and Performance Center. A new Continuous Monitoring Center is under development and expected to be operational by the end of 2025.

Proactive Ignition Mitigation Task Force: In mid-2025, PG&E activated a Proactive Ignition Mitigation Task Force in response to elevated wildfire conditions and an early PSPS event. Led by the Vice President of Wildfire Mitigation, the task force coordinates multiple workstreams addressing ignition risks and corrective actions. Initiatives include a pilot program targeting distribution long spans over 600 feet; corrective tagging of transmission spans with missing vibration dampers; and a program to replace approximately 8,300 higher-risk service drop connectors in HFTD areas with breakaway devices.

Asset Age and Useful Life: The ISM observed an emerging concern with PG&E's protective relays, which are critical to isolating failures and maintaining system stability. PG&E has nearly 30,000 relays in service, of which 23% are past their useful life; without additional replacements, this figure is projected to rise to 37% by 2030. PG&E estimated that $1.5 billion of relays will reach end-of-life in the next five years, with an additional $1.3 billion backlog already past useful life ($2.8 billion total). PG&E indicated that relays are not yet included in Integrated Grid Plan investment planning but are expected to be incorporated in the future.

Mega Bundle Program Update: PG&E expanded its Mega Bundle Program in 2025, following a 2024 pilot that consolidated maintenance tags by circuit and closed approximately 8,200 tags representing $100 million of work. The 2025 program refined its approach by grouping tags based on proximity and circuit protection zones, resulting in finalized workplans covering 16,891 tags across 21 circuits, valued at approximately $200 million. PG&E reported that the 2024 program reduced pole and overhead replacement costs by nearly 20% and achieved a 67% reduction in outages compared with other areas. PG&E anticipates similar benefits in 2025. The ISM observed a 1,714-tag Mega Bundle project in the field, where contractors and PG&E staff coordinated safety, logistics, and QA/QC close-out processes. PG&E anticipates continued growth of the program, with 50,000 open tags preliminarily planned for 2026.

Vegetation Management: PG&E continued to implement multiple vegetation management programs during 2025, including Routine Patrols, Second Patrols, and specialized initiatives such as VMOM, FTI, and TRI. During this ISM reporting period, the ISM observed coordination challenges between the FTI program and system undergrounding with tree inspection and abatement activities occurring in close proximity to and near the same timeframe as circuit undergrounding work. PG&E provided information on "constrained trees," where approximately 201,000 cases require permitting or resolution of other issues before they can be mitigated. Constrained trees can be escalated when inspections show a change of condition to P1 or P2 - actively failing/contacting the conductor, or may fail within 60 days, respectively. In this situation the tree or vegetation will be mitigated without completion of the constraint process.

GAS OPERATIONS

The ISM's review of PG&E's natural gas operations during this reporting period identified notable observations across several focus areas. These include benchmarking of transmission incident rates against industry averages, oversight of clearance operations and corrective actions, and evaluation of PG&E's excavation damage prevention activities. Observations also addressed leak survey coverage, backlog reduction efforts, and performance in leak management and repair programs.

Transmission Incident Rates vs. Industry: The ISM compared PG&E's reportable transmission pipeline incidents against PHMSA industry data using five-year rolling averages. PG&E's total incident rate, which once exceeded industry averages by more than double, has steadily declined since 2018 and by 2024 was closely aligned with peer utilities. The improvement has been driven largely by reductions in excavation damage, while equipment and material failure rates have also moved toward industry norms.

Gas Clearance Operations: PG&E's gas clearance process governs the isolation, purging, and restoration of pipelines, with defined roles, approvals, and field verification steps. During this reporting period, the ISM performed a field review of a 10-mile 'In-Line Inspection Upgrade Project', and observed implementation of daily safety analyses, lockout/tagout verification, use of vent stacks and exclusion zones, and coordination with the Gas Control Center. PG&E also reported progress on gas clearance corrective actions from the Kettleman Root Cause Evaluation (detailed in ISM Report 6).

Damage Prevention: PG&E reported to the ISM on its Damage Prevention Program - designed to reduce excavation-related threats to transmission and distribution pipelines through public outreach, locate and inspection protocols, and risk-based prioritization. PG&E's public awareness campaign (811 One-Call service) reached nearly 35 million impressions in 2024, a 15% increase over a 2-year period. Total excavation damage saw a 13% decrease over the same period. "Repeat offender" damage saw a reduction of 40% year-on-year, which PG&E attributes to targeted excavator outreach and better compliance.

Leak Survey and Leak Management: PG&E's performs leak surveys: annually in business districts and at least once every three years in other areas. The purpose of these surveys is to identify and repair leaks that affect public safety, reliability, and the environment. PG&E reported that more than 1.3 million service lines and 13,000+ miles of distribution mains have been surveyed annually since 2022. Inspection and survey backlogs associated with access issues have shown notable reductions, year-on-year. Causes of leaks include excavation damage, corrosion, equipment failures, and material issues, with excavation-related leaks posing the highest hazard classification. PG&E indicated that leak survey and repair data are integrated into PG&E's asset management programs to inform capital replacement of older pipe types, corrosion control, and corrective maintenance planning, and are benchmarked against peer utilities through the American Gas Association.

BACKGROUND

In conjunction with 1) California Public Utilities Commission (CPUC) Decision 20-05-053, 2) the Bankruptcy Plan of Reorganization for Pacific Gas and Electric Company and 3) the findings included in the Kirkland & Ellis LLP Federal Monitorship Final Report dated November 19, 2021 (Federal Monitorship Report) a need for a safety monitor was identified. Through Resolution M-4855, the CPUC approved implementation of an ISM of PG&E to fulfill a role that supports the CPUC's ongoing safety oversight of PG&E's activities.

Filsinger Energy Partners, Inc. (FEP) was engaged to serve as the ISM of PG&E. The ISM contract executed between FEP and PG&E dated January 27, 2022 (the ISM Contract) outlines a scope of work that includes FEP monitoring certain safety and risk aspects of PG&E's electric and natural gas operations and infrastructure. In consultation with the CPUC, the ISM identifies and performs certain monitoring activities associated with areas outlined within the scope of the ISM Contract. The areas of focus are designed to take into consideration the findings from the Federal Monitorship Report; safety related findings from areas identified through the ISM's fieldwork, inspections, and analyses; and provide complementary oversight and monitoring activities that are not unnecessarily duplicative, consistent with CPUC Resolution M-4855.

The ISM's first six reports, hereafter referred to as "ISM Report 1", "ISM Report 2", "ISM Report 3", "ISM Report 4", "ISM Report 5", and "ISM Report 6" (or "ISM Previous Reports", collectively), covered the periods January 27, 2022, through September 30, 2022 (published October 4, 2022), October 1, 2022, through March 31, 2023 (published May 2, 2023), April 1, 2023, through September 30, 2023 (published October 4, 2023), October 1, 2023, through March 31, 2024 (published April 4, 2024), April 1, 2024, through September 30, 2024 (published October 4, 2024), and October 1, 2024, through March 31, 2025 (published May 15, 2025), respectively. The ISM Previous Reports identified work performed in associated focus areas during the respective reporting periods.

This PG&E Independent Safety Monitor Status Update Report, hereafter referred to as "ISM Report 7", covers the reporting period April 1, 2025, through September 30, 2025. It was developed based on the stipulations of the ISM Contract and the reporting directive included within CPUC Resolution M-4855. This ISM Report 7 is designed to summarize the oversight activities performed by the ISM during the reporting period described and the related observations.

This ISM Report 7 also includes a summary of potential emerging risks identified during the oversight activities performed during the current ISM reporting period. With respect to potential emerging risks, consistent with the ISM Contract scope, the ISM has documented the initial observations and performed certain initial monitoring activities. Depending upon the observations, in consultation with the CPUC, it may be determined that the ISM will perform additional monitoring activities.

The ISM's role is not to provide suggestions for addressing the issues identified or rank the order of priority or risk. Relatedly, the ISM monitored PG&E's activities to the extent agreed upon within the confines of the ISM Contract or as otherwise agreed to between the ISM and the CPUC.

The information included in this ISM Report 7 should be considered a "snapshot" of observations during the current ISM reporting period. The ISM may continue to perform monitoring activities related to certain observations noted in this ISM Report 7. Not all topics and/or observations identified in the ISM Previous Reports will be discussed in the current report. If the ISM did not identify new material changes or information during the current ISM reporting period, the topic/observation may be omitted from the current report and reintroduced in the future when material additional changes or information are obtained. Observations may change for various reasons (e.g., additional information becomes available, operational changes are implemented by PG&E, etc.). The ISM derived general facts and information contained within this report from internal PG&E meetings, presentations, data, and external reports which may not always be footnoted. Unless otherwise stated, the ISM did not independently confirm facts and information provided to it by PG&E or any third parties.

GENERAL OBSERVATIONS

The Federal Monitorship Report identified "retaining a core leadership team, in the wake of near constant turnover in recent years" as one of the "most salient challenges PG&E faces going forward."

The ISM monitored and reported specific leadership changes in each of the ISM Previous Reports. During the current ISM reporting period, the ISM reviewed and summarized the leadership changes occurring at the officer level (Vice President and above) since January 2022. The organizational charts included in Figure 1 summarize these changes, highlighting the leadership positions held by two or three different individuals, and new positions added since the ISM's engagement.

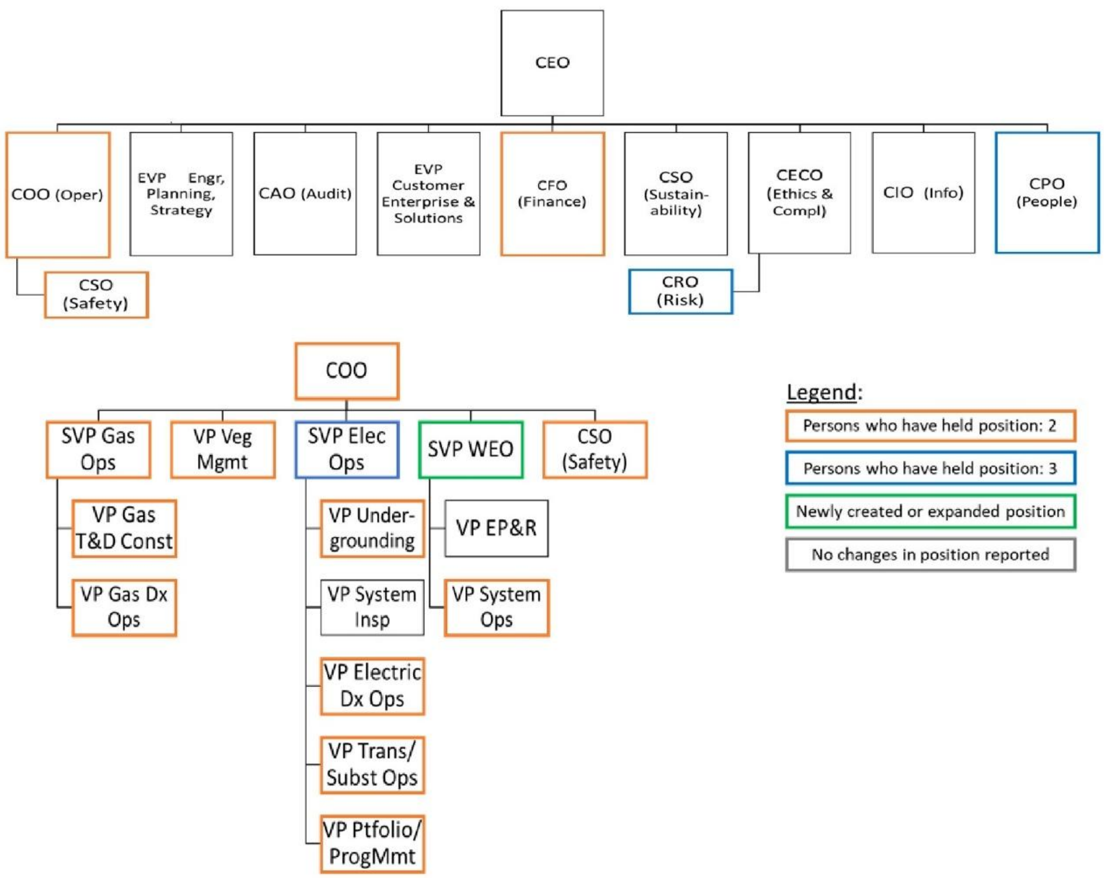

Figure 1: PG&E Senior Leadership Changes Since January 2022

The following provides a summary of the leadership changes during this ISM Reporting period:

- The Human Resources responsibilities of the former Executive Vice President of People, Shared Services, and Supply Chain position reside with the Chief People Officer. Shared Services and Supply Chain responsibilities have been shifted to other officers within the company.
- The Vice President of Gas Distribution Operations was promoted to Senior Vice President of Gas Operations who retired.

- PG&E filled the Vice President of Gas Distribution Operations on an interim basis by an internal PG&E employee.
- A Senior Director currently leads the Operations Support position under Electric Operations.

The ISM will continue to monitor leadership changes and related potential impacts relative to the areas within the scope of ISM responsibilities.

ELECTRIC OPERATIONS OBSERVATIONS

The ISM's electric operations and infrastructure focus in this ISM Report 7 is directed toward: 1) Reliability Trends, 2) Ignition Trends, 3) Ignition Investigations, 4) Equipment Investigations, 5) Fast Trip Programs, 6) Continuous Monitoring Programs, 7) Risk and Mitigation Prioritization Models, 8) Risk Tracking and Risk Reduction, 9) Integrated Grid Plan, 10) Asset Age and Useful Life, 11) Distribution Inspections, 12) Distribution Maintenance, 13) Transmission Trends, Inspections, and Infrastructure, and 14) Vegetation Management

RELIABILITY TRENDS AND OBSERVATIONS

As described in ISM Previous Reports 2, 5 and 6, PG&E's capital expenditure on reliability-oriented projects dropped over the past ten years, with targeted reliability investments shifted to support wildfire risk mitigation since 2017. While this increased wildfire mitigation spending correlates with a decrease in the number of PG&E facility ignitions in high-risk areas, the reduction in targeted reliability capital, combined with the introduction of the Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) programs in 2018 and 2021, respectively, all contributed to substantial increases in the average duration and frequency of PG&E customer outages over the 2015 to 2024 period.

While PG&E files an Annual Electric Reliability Report with the CPUC each year that provides additional background on PG&E's reliability statistics, breakdowns by distribution and transmission systems and districts, and provides commentary on major storm events and reliability trends, this section focuses on PG&E's efforts and workplans designed to improve the reliability of its electrical system. This section also details PG&E issues relating to historical reporting of outage data to the ISM, and the program PG&E is implementing to improve its external data reporting.

The worsening of PG&E's system reliability over time can be seen in Figure 2, which shows PG&E's Customer Average Interruption Duration Index (CAIDI), its System Average Interruption Frequency Index (SAIFI), and its System Average Interruption Duration Index (SAIDI), which is the combination of the two prior indices, multiplying the average duration of each customer outage with the average number of times a customer experiences an outage on PG&E's system. As seen in this Figure, the 188% increase in SAIDI over the 2015 to 2024 period (which places PG&E in the 4th quartile among U.S. electric utilities), is due to the combination of the average customer outage duration increasing 37% over this period, and the average outage frequency increasing 110% over this same period. The ISM is reporting on PG&E's reliability as a public safety issue, as loss of power can potentially negatively impact vulnerable populations (e.g., people medically dependent on electricity, or requiring air conditioning during extreme heat events), hospitals, people dependent on well water, emergency response, communications networks, etc.

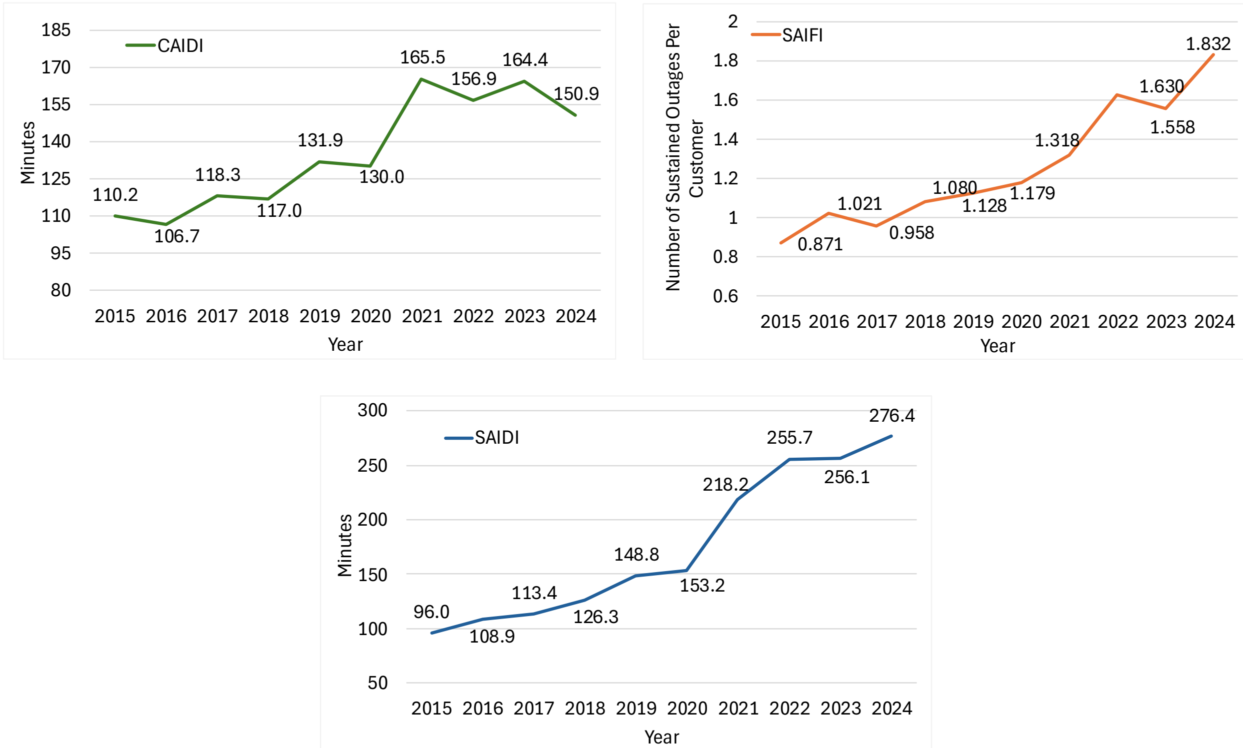

Figure 2: PG&E CAIDI, SAIFI and SAIDI 2015-2024[1]

PG&E recently assembled System Performance Reliability and Resilience Strategy teams in order to increase the analytical focus of the reliability group's work. These teams also lead the Reliability Task force, which oversees and coordinates numerous projects specifically targeting reduced outage duration and frequency. As part of the assemblage of this expanded reliability team, PG&E also shifted its Director of Risk Management and Analytics to Senior Director of the reliability group.

Figure 3 provides an overview of the task force's primary plans to reduce PG&E's SAIDI by a targeted 38.5 minutes (a 14% reduction) from its 2024 actual.

In creating its SAIDI projection for 2025, the reliability group started off with the assumption that 2025 would see similar environmental conditions, and similar PSPS and EPSS event frequencies as in 2024. The ISM's section on Fast Trip Programs (EPSS), notes that 2025 started off with more extreme conditions earlier in the year. This in turn resulted in higher EPSS outage counts during the first seven months of 2025 than during the comparable periods in earlier years.[2] Despite this setback, PG&E has been able to improve from these higher EPSS outage counts, and from a number of large, non-PSPS, customer outage events during the first

[1] These CAIDI, SAIFI and SAIDI figures are for sustained outages (i.e., being without power for more than five minutes), and include planned outages, but exclude outages that occurred during major event days.

[2] PG&E experienced 1,186 EPSS outages during the first seven months of 2025, versus an average of 934 EPSS outages for the 7-month period from 2022 to 2024.

few weeks of the year. As of September 29, 2025, SAIDI is approximately 21 minutes higher than its year-to-date path to achieve 238.2 SAIDI minutes by year-end.

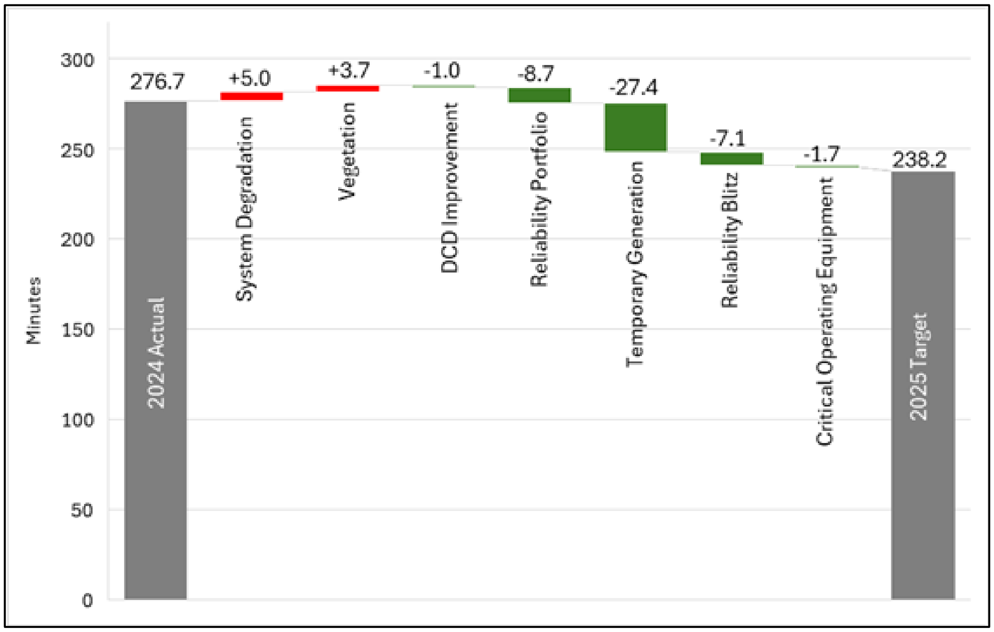

Figure 3: SAIDI Waterfall From 2024 Actual to 2025 Projected (not updated with YTD 2025 actuals)

The individual components shown in Figure 3 that are projected to impact 2025 reliability (which do not include updates based on 2025 actual performance) include:

- System degradation (+5 minutes): PG&E stated this represents the projected impact due to the potential deterioration of transmission, distribution and substation asset performance with increasing average system age.
- Vegetation: (+3.7 minutes): PG&E stated this projected increase is based on a trend line of the past three years of vegetation-caused SAIDI.[3]
- Downed Conductor Detection (DCD) Improvement (-1 minute): PG&E stated this represents the projected SAIDI reduction as a result of more rapid and targeted detection of certain high impedance faults, and shorter patrols and restoration times on distribution lines due to additional DCD installations in 2025 plus DCD device setting adjustments.
- Reliability Portfolio (-8.7 minutes): PG&E stated these savings are projected to arise following completion of a portfolio of 1,356 specific maintenance projects (1,060 completed by September 29, 2025) which were prioritized and selected based on their ability to improve system reliability.
- Temporary Generation (TG) (-27.4 minutes): PG&E uses TG to mitigate power loss

[3] The ISM reviewed PG&E's cumulative customer minutes interrupted (excluding momentary and major event day outages) for vegetation-caused outages, and observed an increasing trend from approximately 90.4 million minutes in 2020 to approximately 227 million minutes in 2023, with a decline in 2024 to approximately 201 million minutes. PG&E noted that the trend of the 2022 – 2024 vegetation caused SAIDI (28.0, 39.5, and 35.5) results in a slope of 3.7 minutes.

caused by planned or emergency work. PG&E entered into multi-year contracts for the use of mobile generators throughout its service territory, and PG&E's reliability group requests that field teams involved in planned outages forecast to exceed 30,000 customer minutes utilize TG after submitting a Temporary Generation Intake Request Form.

- Reliability Blitz (-7.1 minutes): PG&E also selected 150 distribution circuits in both HFTD and Non-HFTD areas prioritized by historical outage frequency for inspection and prioritized repair. These inspections are being conducted by ground (125 circuits) and by aerial drone (25 circuits), with 146 circuits completed by the end of September 2025, resulting in 731 aerial and 2,610 ground-based maintenance finds (including 48 A tag and 176 X tag finds).
- Critical Operating Equipment (-1.7 minutes): maintenance work focusing on high priority reclosers, switches, sectionalizers and interrupters to allow for improved isolation of faults and minimization of customer impacts.

PG&E stated that a major factor in the decline in its reliability over the past ten years is the increase over time of the number of distribution circuits that are operating in an abnormal configuration.[4] PG&E notes that it has approximately 4,200 abnormal conditions, resulting in approximately 41% of its 3,400 distribution circuits operating in an abnormal condition.

These abnormal conditions also do not allow proper operation of all of PG&E's installed Fault Location, Isolation, and Service Restoration (FLISR) systems. FLISR is an automation technology used to improve reliability by automatically detecting faults, isolating the problem area, and restoring service to as many customers as possible without waiting for manual switching. By quickly opening and closing automated switches, many of the customers not in proximity to the fault may be restored in minutes, rather than being without power for the full duration of the repair.[5] PG&E launched its first pilot testing of FLISR on six circuits in 2011, and FLISR is now installed on approximately 960 distribution circuits. Only 526 of these circuits are currently FLISR enabled, due to critical operating equipment (COE) requiring service. PG&E's workplan for COE repairs on its FLISR disabled circuits include approximately 100 COE during the remainder of 2025, approximately 30 in 2026, approximately 800 in 2027,

[4] PG&E uses the term "circuits in abnormal configuration" to describe a circuit with a device that is tagged in the Distribution Management System indicating the device is not in the normal state (Switching Tag) or the device may not operate as designed (Critical Operating Equipment (COE)). For example, a Switching Tag might indicate that a normally open switch is currently closed. A COE tag indicates that the distribution system cannot be operated as designed or intended in a normal configuration. Examples include (1) a device, such as a switch or recloser, that is stuck open and therefore cannot be used to restore customers during a planned or unplanned outage, (2) a capacitor with a blown fuse that is pending replacement by a crew, resulting in the capacitor being temporarily disabled, (3) a distribution supply substation transformer Load Tap Changer that has failed and cannot operate as intended to provide voltage support within our Rule-2 limits for normal configuration, and (4) a Supervisory Control & Data Acquisition (SCADA) capable device where SCADA has malfunctioned, therefore requiring manual operation.

[5] In one example, a PG&E feeder outage impacted 2,628 customers. PG&E's FLISR calculated four restoration options based on system loading and automatically prioritized options based on SCADA health, switching complexity and system loading. Within three and half minutes, the FLISR system helped restore service to more than 85 percent of impacted customers.

with the remaining approximately 1,300 COE having no current work plan date.

In addition to the above programs, PG&E is also undertaking several other reliability-oriented activities, including:

- Outage review team (ORT): PG&E's 6-person ORT review each outage for reliability improvement opportunities. Through the end of September 2025, the ORT completed approximately 1,500 outage reviews which resulted in the implementation of approximately 1,200 reliability improvement actions.[6]
- 2+ Crew: PG&E is expanding the size of select inspection crews so that certain repairs can be made at the time of identification, rather than reporting the issue and waiting for a repair assignment.
- Underground cable replacement: underground equipment can have long repair times, and underground equipment failures are significant contributors to SAIDI. The reliability group is working to prioritize PG&E's 2025-2026 cable replacement workplans for earlier work in areas with higher historical outage frequency.
- Non-traditional opportunities: PG&E is also in earlier stages of investigating mobile battery storage system deployment, work bundling of conductor fatigue failures, updates to transformer loading standards, and conducting a transformer lifetime analysis.

Historical Outage Data

Earlier in 2025, the ISM identified issues with certain HFTD designations within outage data provided by PG&E. PG&E later confirmed data discrepancies and notified the ISM that the inaccurate data provided to the ISM was limited to HFTD designation of individual historical outage events. The ISM also learned that data issues also impacted various reporting being made to the CPUC. The ISM will continue to report on outage trends in HFTD and Non-HFTD areas using corrected data in future ISM Reports.

The ISM and PG&E discussed the cause of the issue and PG&E's plans to correct the situation. In response, PG&E stated it is launching a multi-year Wildfire Intelligence Reporting Engine (WiRE) initiative to drive greater alignment across spatial and tabular Wildfire Mitigation Plan (WMP) data reports, leveraging the use of its Foundry data platform.[7] Through WiRE, PG&E is looking to create a single, unified record of evidence for each WMP initiative and other key wildfire data.

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[6] ORT reliability improvement actions have included recommending supplemental patrols, investigations or engineering reviews, requesting the installation of fault indicators, animal mitigations, FLISR enablement, DCD, or lightning arrestors, setting changes for fast trip devices, etc.

[7] PG&E noted that its spatial and tabular reports were historically developed either at different times or through separate processes, resulting in discrepancies across datasets. These differences stemmed from the unique data points, filters, and transformations required for each report, which, while technically accurate, produced inconsistent outputs.

IGNITION TRENDS AND OBSERVATIONS

PG&E is continuing to see a downward trend in the number of ignitions within its higher risk HFTD areas where the majority of its wildfire mitigation efforts and expenditures are being incurred.

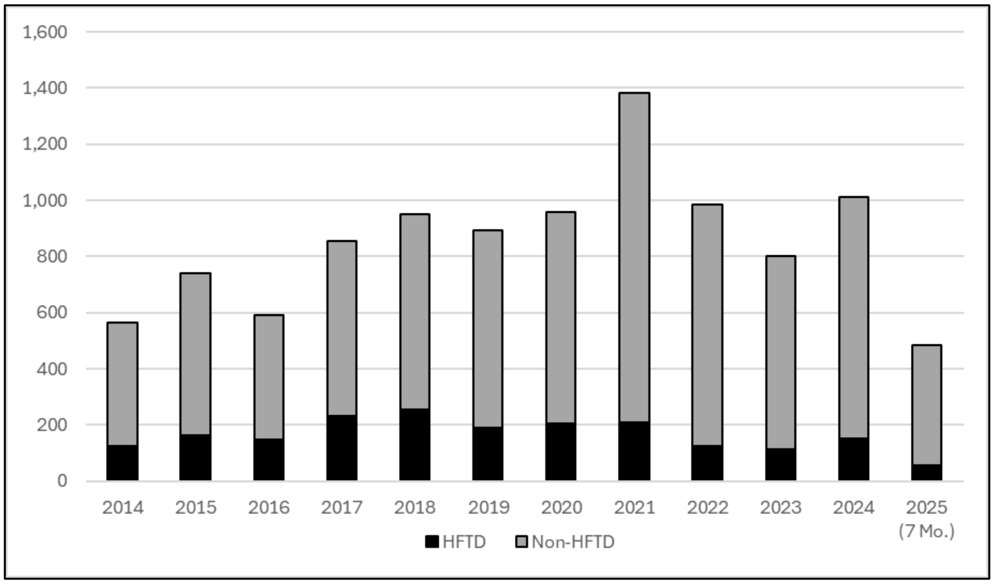

Figure 4: Total PG&E Ignitions by Tier (2014 to July 2025)

Figure 4, which presents total ignitions recorded by PG&E for the full years 2014 to 2024 and for the seven-month period of 2025, shows a reduction in HFTD ignitions from a high of 257 in 2018 down to a low of 113 ignitions in 2023. While HFTD comprises approximately 30% of both PG&E's transmission and distribution wires, the percentage of ignitions in HFTD declined from a peak of 27% in 2017 down to 12% seen during the first seven months of 2025.

Table 1: Total HFTD and Non-HFTD Ignitions by Suspected Cause: 2025 Jan-July vs. Prior Seven Month 3- and 5-Year Averages[8]

	HFTD			Non-HFTD		
Suspected Cause	2025 (7 Mo.)	2022-2024 (7 Mo. Avg.)	2020-2024 (7 Mo. Avg.)	2025 (7 Mo.)	2022-2024 (7 Mo. Avg.)	2020-2024 (7 Mo. Avg.)
3rd Party	3	9	10	63	62	61
Animal	3	5	7	105	70	61
Contamination	1	5	5	74	67	50
Equipment	20	19	24	116	169	184
Other	12	9	7	24	15	13
Unknown	1	1	2	4	4	8
Vegetation	16	31	40	42	52	51
	56	79	95	428	439	428

Table 1 shows the number of ignitions in HFTD and Non-HFTD by suspected cause for the first

[8] The Other category includes ignitions caused by 2nd party contact (i.e. PG&E contractor activity), vandalism, lightning, and ignitions under investigation.

seven months of 2025 compared to the 3- and 5- year averages for the same seven-month period.

As seen in this table, PG&E's HFTD ignitions during the first seven months in 2025 are down 29% and 41% versus the 3- and 5-year averages of the same seven-month period, respectively. Note that ignition frequency is influenced by weather variations, and discussions on weather normalization is included below. While most HFTD categories declined, the largest contributor was vegetation-caused outages, which declined 49% and 60% over the same periods, respectively. Total Non-HFTD ignitions were stable over these comparative periods, with the large decline in equipment failure related ignitions offset by the increase in animal-caused ignitions in more recent years. The majority of these animal-caused ignitions in the first seven months of 2025 were listed as bird nest contact.

PG&E tracks both CPUC reportable ignitions and non-reportable ignitions.[9] The ISM observed that over the past ten years the percentage of CPUC ignitions compared to total (CPUC reportable + non-reportable) ignitions averages approximately 70% in HFTD vs 50 % in Non-HFTD. [10] Since non-reportable ignitions have a fire spread of less than one meter, the ISM's reviewed this data to determine if PG&E's mitigations at limiting ignition impact (such as the expansion of vegetation clearing at the base of poles, and the introduction and expansion of fast trip devices) was possibly reducing the percentage of CPUC reportable ignitions. Apart from the consistent differences in the CPUC reportable percentage between HFTD and Non-HFTD areas, the ISM did not observe any longer-term trends in the CPUC reportable percentages themselves.

Relative to PG&E's more recent ignition experience, Figure 5 represents the further reduction in CPUC Reportable ignitions in HFTD/HFRA in 2025 year-to-date versus 2024, the 2022-2024 three-year average, and PG&E's target for 2025.

Weather conditions vary from year to year, and these varying weather conditions can significantly impact the level of ignition activity in any particular year. PG&E uses its Fire Potential Index (FPI) scores as a proxy for days with higher fire spread potential in order to normalize the year-to-year ignitions data for weather. On the R1 to R5 FPI scale, PG&E selected R3+ days as the time period which has the highest correlation to more catastrophic fires.[11] Through September 23, PG&E recorded 35 R3+ CPUC Reportable ignitions in 2025, which was below the 45 experienced during the same period in 2024, and which was equal to the prior three-year average. This prior three-year period included years with less extreme fire potential weather. To further normalize these R3+ ignitions, PG&E looks at the number of ignitions in

[9] A CPUC reportable ignition is an event that meets CPUC reporting criteria including ignitions that are associated with utility equipment and that result in a fire spreading more than one meter from the source.

[10] Reasons for this disparity in percentage of CPUC reportable ignitions relative to the total between HFTD and Non-HFTD may include more rapid detection and response to ignitions in more densely populated Non-HFTD areas, and greater abundance of non-combustive ground materials in Non-HFTD.

[11] In modeling 2,437 historical fires (utility and non-utility caused) greater than 100 acres in size, PG&E observed that fires during R3 and higher FPI conditions accounted for 95% of the acres and 100% of the fatalities and structures destroyed.

R3+ conditions divided by the number of miles in R3+ conditions times 100,000 over a rolling 12-month period. Using this method, the normalized R3+ ignition figure of 1.06 at September 23, 2025, compares favorably against the level of 3.23 seen at the end of 2017, but is slightly higher than the 1.03 and 0.93 levels seen at the end of 2022 and 2023 when weather conditions were less extreme, and below the 1.41 level at the end of 2024.

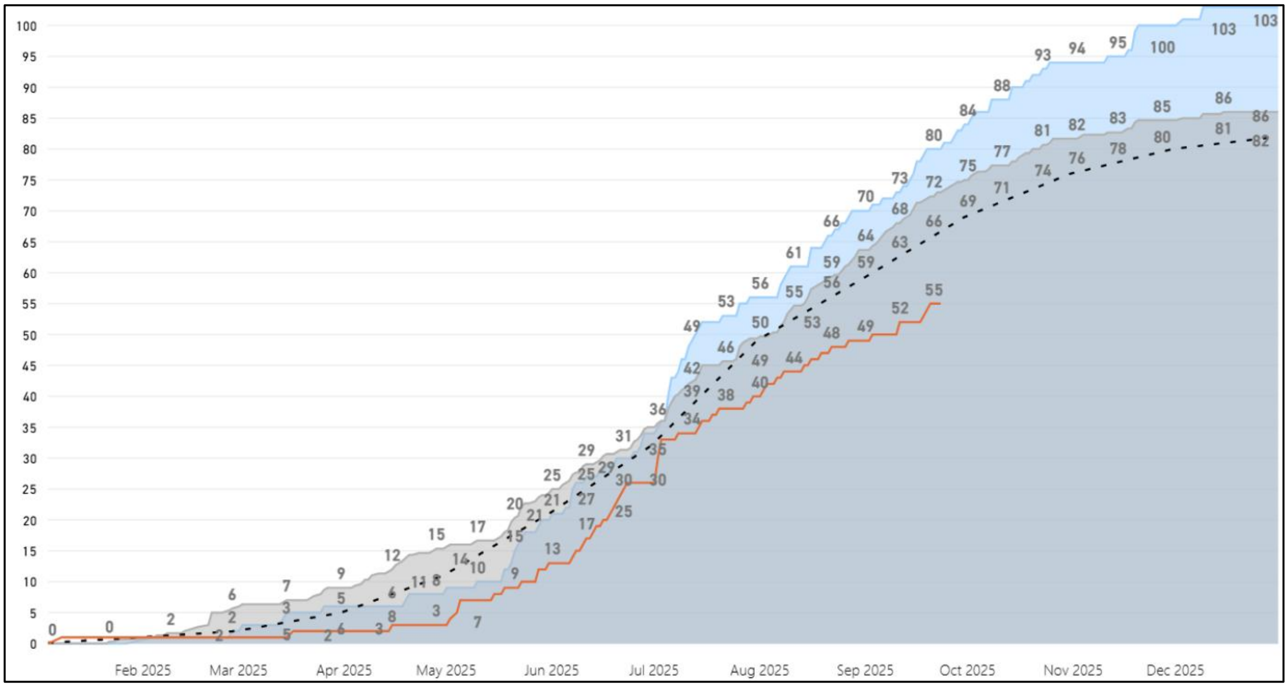

Figure 5: PG&E CPUC Reportable Ignitions in HFTD/HFRA

Of these 35 R3+ CPUC Reportable Ignitions in HFTD through September 23, 2025, 21 of these occurred on primary distribution lines, 12 occurred on secondary and service distribution lines and two occurred on transmission lines.

IGNITION INVESTIGATIONS

In ISM Report 6, the ISM provided its initial observations on PG&E's Enhanced Ignitions Analysis group, and its primary deliverable, the Preliminary Ignition Investigation Report (PIIR), which provides a comprehensive investigative analysis into the circumstances and suspected root causes of certain in-scope ignitions. In addition, the ISM detailed PG&E's use of these PIIRs to evaluate the effectiveness of hazard barriers designed to mitigate risk, and to document follow-up investigative work that may be performed by its vegetation management team,[12] its Applied Technology Services (ATS) engineering laboratory, and its Asset Failure Analysis (AFA) group.

[12] Extent of condition vegetation reviews following a vegetation caused ignition are called reactive Vegetation Management for Operational Mitigation, and are detailed in the Vegetation Management section of this ISM Report.

Enhanced Ignition Investigation Group

Figure 6 provides an overview of the steps involved in the EIA process previously described in ISM Report 6.

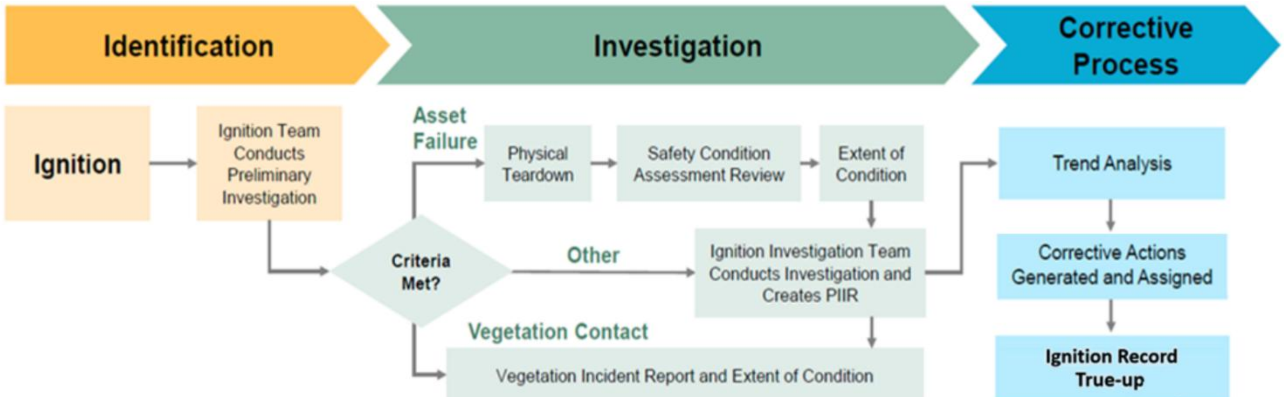

Figure 6: The Enhanced Ignition Analysis Process

One of the items under the Corrective Process in Figure 6 not previously detailed by the ISM is the Trend Analysis step, where EIA may focus on recurring circumstances that can lead to the identification of opportunities to address common risk, rather than corrective actions for single ignition incidents. During the current ISM reporting period, several of these emerging trends were presented to the ISM and PG&E's Wildfire and Risk Management leadership:

- <u>Low hanging communication lines</u>: EIA determined that low hanging communication lines get struck by vehicles approximately 10 times per year, with approximately 70% of the ignition arising from this contact causing fires that spread beyond three meters. To help mitigate this, PG&E began using LiDAR to proactively identify low hanging communication lines above drivable surfaces in HFTD,[13] and shared these extent-of-condition findings with the telecommunications companies. Before issuing a Third-Party Notification, PG&E employees or contractors first perform a field validation to physically measure if a line fails to meet the minimum clearances outlined in G.O. 95, Rule 37. This field validation is required as LiDAR can sometimes generate erroneous false positives, and field conditions may have changed since the LiDAR was captured. Field validation also allows confirmation of the owner of a non-compliant line. In a follow-up pilot, PG&E field validated 515 locations identified by LiDAR and confirmed that 334 were non-compliant, for a 65% validation rate. As a result of this process, PG&E is actively engaging with the communication companies, which began accelerating their mitigation of non-compliant lines in 2025 after the sharing of this

[13] 2,969 communication lines were identified with a clearance of 13 feet, 8,093 with a height of 14 feet (the maximum compliant vehicle height) and 17,887 with a height of 15 feet (minimum G.O Compliance height). Through initial field validations and desktop review of the data, this population was further reduced to approximately 14,800 HFTD locations. PG&E is working with the communication companies which are conducting their own field validations, and PG&E confirms that approximately 1,600 non-compliant lines were remediated through June 2025.

data.

- High-Impedance Faults on EPSS-Enabled Circuits: EIA determined that 71 of 171 2023-2024 facility ignitions in HFTD/HFRA were ignitions that occurred on EPSS enabled circuits, with 55% (39) of these involving high impedance faults. Further investigation found that an additional 55% of these high-impedance faults did not trip protective devices. Where default sensitive ground fault (SGF 1.0) trip settings were not sensitive enough, PG&E is in the process of lowering default SGF 1.0 thresholds to require a more sensitive current pickup level with a shorter duration (SFG 2.0).Further, PG&E is working with partner vendors to develop an algorithm that uses inverse-time ground protection capability, as part of DCD improvements, to leverage an "integrating" function able to capture small leakage energy associated with high-impedance ground faults. The implementation of these solutions, including expanded downed conductor detection deployment, were detailed in ISM Report 6.
- Long Span Ignitions: EIA's analysis shows that long spans in excess of 600 feet on distribution lines make up 1.9% of primary spans in HFTD, but account for 9% of ignitions. Further details of this situation and the pilot program initiated to follow up on these findings are provided in the Risk Tracking and Risk Mitigation section.
- Avian contact on transmission lines: In 2024, PG&E suspected avian contact to be the cause in seven of the nine CPUC reportable transmission ignitions, with five of those happening during the more extreme R3+ FPI conditions. Corrective actions surrounding these circumstances are detailed in the Risk Tracking and Risk Mitigation section, with early 2025 results presented in the Transmission section.

ISM PIIR Reviews

During the current ISM reporting period, the ISM reviewed 31 PIIRs which were completed and issued between February and July 2025. These PIIRs cover ignitions which ranged from July 2024 through June 2025. The issuance rate for these 31 PIIRs of approximately five per month is down from the 113 PIIRs issued in 2024 (averaging 9.4/month), 125 in 2023 (averaging 10.4/month) and 154 in 2022 (averaging 13/month). PG&E descoped mandatory PIIRs for some ignition types over time which resulted in fewer detailed ignition investigations and PIIR being issued in 2025. PG&E stated that this descoping was to allow EIA to focus its efforts on higher risk incidents. PIIRs are currently required for all CPUC reportable ignitions in HFTD/HFRA and in Non-HFTD areas that are EPSS enabled. While all transmission ignitions previously received PIIRs regardless of their location, starting in April 2025 only those transmission ignitions that occurred in HFTD/HFRA now receive a PIIR. In 2024, PG&E also descoped ignitions involving tracking/contamination, along with ignitions on non-EPSS enabled lines involving vehicle, balloon and animal contact.

The 31 PIIRs reviewed by the ISM were split between seven transmission and 24 distribution ignitions, with 14 ignitions attributed to equipment failure, 10 to vegetation contact, four to 'Unknown' and three to animal contact. ATS/AFA investigation was conducted on 15 of these PIIRs, with seven corrective actions being generated. Each of the vegetation caused ignitions received an extent of condition review, with half finding no additional trees to mitigate, and the others finding between one to six trees to mitigate. One extent of condition review found additional trees that needed to be mitigated as a result of fire damage from the ignition.

Ignitions With Open Maintenance Tags

Four of the reviewed PIIRs involved ignitions occurred with open maintenance tags connected to the suspected initiating cause. Two of these involved maintenance tags that were past their scheduled due date.

One of these maintenance tag ignitions occurred on a transmission line in October 2024 and involved a flashed insulator which arced and jumped to the uninsulated down guy, which in turn energized the adjacent metallic fence which caused an ignition along the fence line.[14] The PIIR notes that a pre-existing Line Corrective (LC) notification was created for the replacement of the flashed insulators after being identified during an aerial inspection in April 2021. The tag received priority "E", corresponding to Level 2 in GO 95 Rule 18. At this time, PG&E assigned one-year durations for all tags with priority "E", resulting in an original Required End Date (RED) of April 2022. This tag was not planned for completion in 2022 and consequently received a Field Safety Reassessment (FSR) in November 2022, to evaluate whether the condition had degraded further and required escalation. The FSR concluded that the work could be deferred until November 2023, and the Centralized Inspection Review Team (CIRT) concurred with the recommendation. At the start of 2023, PG&E changed transmission procedures and guidance to align the internal priorities A, E, and F directly with CPUC GO 95 Rule 18 Levels 1,2, and 3, and to align their maximum allowable RED with Rule 18 timeframes. Since Rule 18 allows up to three years for Level 2 conditions not impacting worker safety in Non-HFTD areas, in January 2023, CIRT re-reviewed the LC tag against the updated guidance to evaluate whether the original one-year RED was still appropriate. CIRT determined that the tag should receive the maximum three-year timeframe allowed under Rule 18 and updated the RED to April 2024. The PIIR noted that if PG&E completed this work by either the original RED, the recommended completion date from the 2022 FSR, or the updated RED, the ignition incident may have been prevented.

In order to conduct a trend analysis on ignitions with open tags connected to the suspected initiating event, the ISM requested data from PG&E which show the number of ignitions which occurred with open and open/overdue maintenance tags since 2020. Table 2 shows a total of 29 ignitions having occurred with open/related tags, with both the number of open, not-yet-due, and open and overdue tags both showing increasing annual trends. Of these 29 open tag ignitions, seven occurred on transmission lines, with 21 involving damaged or missing equipment, two involving overloaded equipment, four involving animal contact (3 with nest debris, one to install bird protection) and three with overgrown or clearance impaired vegetation.

[14] PG&E flagged that this down guy should have been insulated and issued a corrective maintenance tag in 2021 for a missing fiberglass rod which was open at the time of the ignition. PG&E conducted an aerial drone Safety Condition Assessment Review after the ignition on 5 spans in both directions and generated additional notifications for the repair of missing fiberglass rods on guy wires.

Table 2: Open Maintenance Tags Connected to Suspected Ignition Initiating Event

	2020	2021	2022	2023	2024	2025 (YTD 7/25)
Non-Overdue Maintenance Tags	0	0	1	2	2	4
Overdue Maintenance Tags	1	3	4	1	5	6
	1	3	5	3	7	10

While ISM Previous Reports have detailed the circumstances behind the increase in PG&E's backlog of overdue maintenance tags, PG&E's strategy for addressing its tag backlog is detailed in its WMP and is therefore not being investigated by the ISM.

Energized Into Fault Ignitions

The ISM reviewed two PIIRs where the ignitions related to re-energizing into a fault.[15] In these two vegetation-contact ignitions, the patrols were unable to find the source of the fault, and the ignition occurred after the lines were re-energized. In one instance the PIIR noted that fog in the area prevented a proper patrol, causing the tree bark on the line to be missed, and the line to be re-energized prematurely. In the second instance, after the first EPSS trip, an EPSS patrol was conducted to the recommended extent, but did not include the location of the trouble.[16]

The ISM observed an increasing number of these 'energized into fault' ignitions, from two in 2021 to six in 2022, six in 2023, seven in 2024, and nine through the mid-point of 2025. As a result of this increasing trend, PG&E conducted an analysis of the mechanisms, conditions and durations of its patrols. PG&E identified several opportunities from this analysis, including:

- Field communication: developing 5-minute meeting/safety flashes about test-ins and sectionalizing areas that field personnel cannot get eyes on before closing in. Meeting with field and control center personnel to review incidents and identify opportunities for improvement.
- Procedure review: review DCD patrol extent, procedures beyond fuse and trip savers, potential impacts of patrolling full zone when trouble is identified.
- EPSS equipment upgrades: additional DCD installation. EPSS enablement during testing.
- High canopy-density or difficult to access areas: Gridscope prioritization, varying patrol requirements, other technologies.

[15] Re-energized into fault ignitions occur when a fault is already present on a line (for example a tree branch across wires or a downed conductor) and the line is de-energize by protective devices. If the fault is not identified and the line is re-energized before the fault is cleared, the surge of fault current can produce heat, arcing or molten metal that may lead to an ignition. (Ignition 20241302 and 20241346)

[16] PG&E states that the EPSS patrol was conducted to the recommended extent of the on-duty Distribution Operations Engineer, who followed PG&E Standard TD-2700P-26 Section 5.11 for determining patrol locations following device trips on DCD lines. PG&E further stated that its preliminary analysis indicates that the Distribution Operations Engineer not selecting a patrol location which contains the fault location to be a rare occurrence.

Ignitions Involving Improperly Constructed Service Connectors

PG&E's PIIRs identified that five of the investigated ignitions included the identification of improper construction. Two of the five ignitions associated with improper construction had missing vibration dampers on span lengths requiring their inclusion. These long span ignitions are discussed in greater detail in the Risk Trends and Risk Mitigations section. One ignition involved improper construction of a service connector. For this August 2024 ignition, the PIIR reported that the troubleshooter assessed that the cause of the short circuit was due to the construction of the connectors potentially too close to the neutral, creating tension over time under the insulated secondary wire. An AFA engineer reviewed the incident and failure, and concluded that due to a lack of an air gap between the impacted hot leg/conductor and neutral messenger, the two components rubbed together.[17]

PG&E is starting to address improper construction on service connectors. Nine incidents occurred between 2021 and 2024 with similar failure modes.[18] Of these nine incidents, five involved service assets that PG&E believes were installed since 2021. In addition, four ignitions with similar causes occurred during the first seven months of 2025, with two of these constructed earlier in 2025

To address these failures, PG&E is undertaking the following steps:

- <u>5-minute meeting on connector installation</u>: Standards and Asset Failure Analysis is developing a 5-minute meeting on a two-brush method and air gap for service connector installs.[19]
- <u>Hardened service standards</u>: Review ATS results on hardened conductor testing. Prioritizing standards development for newly hardened service cable.

Corrective Action Plan Closures

Most of the corrective action plans (CAP) arising from these 31 PIIR ignitions relate to requests for supplemental training, future maintenance work, incident tracking, and policy updates, but two CAPs involved correcting procedural gaps.

For a September 2024 equipment failure ignition, the PIIR noted that it took 30 minutes before Electric Dispatch contacted the Authority Having Jurisdiction (AHJ), CAL FIRE. The PIIR further stated that "while PG&E's delayed notification to emergency services did not impact the current ignition, in certain conditions, such delays could have an adverse impact on an ignition event."[20] As a result, PG&E created a CAP to update several company standards to require any

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[17] Ignition 20241158

[18] i.e., lack of gap between neutral and service connector insulation, improperly installed connectors.

[19] The two-brush method is a cleaning practice used before installing service drop connectors. It requires using two separate wire brushes, one dedicated to brushing the aluminum conductor and another for brushing the copper (or tinned) connector. The goal is to avoid cross-contamination of dissimilar metals, which can lead to galvanic corrosion. The air gap refers to intentionally leaving a small, visible gap between the service connector and any nearby grounded or grounded-metal components. This prevents moisture paths or unintentional contact that could cause tracking, arcing or a phase-to-ground short.

[20] Ignition 20241317

PG&E employee or contractor performing work on behalf of PG&E who observes a fire or potential fire to immediately contact the AHJ/911.

For another ignition that occurred in November 2024 with a listed "Unknown" cause, the PIIR noted that the troubleshooter observed no evidence, nor obtained any evidence/data/information, to conclusively identify the primary cause of the ignition. The report stated that AFA suspects the ignition was potentially caused by failure of the secondary conductor at the bottom of the pole, under the molding and conduit entry. The report further stated that because the secondary conductor was not retained for ATS analysis, the direct cause of the failure that led to the ignition could not be determined.[21] This ignition led to the creation of a CAP which required the updating of material collection requirements (the closure of which was verified by the ISM) and to tailboard a 5-minute-meeting on the material collection requirement with field personnel (which PG&E completed in February 2025).

As a follow-up, PG&E informed the ISM that it retained 86% of equipment (43/50) that caused an ignition in 2024, versus PG&E's target of 80%. The CAP was to address the seven ignitions where equipment had not been properly collected, with PG&E noting that it aims to increase the frequency with which field personnel will be reminded to recover ignition-related equipment.

EQUIPMENT INVESTIGATIONS

The ISM observed several equipment-related situations emerging over the past two years, where initial isolated incidents were later seen by PG&E as being part of a growing number of clustered equipment defects leading to increasing numbers of operational issues or ignitions. This section details PG&E's experience with liquid-filled fuses (LFF), E-fuses, and line recloser controllers, and provides a history of how PG&E identified each issue, the impacts they were having, and how PG&E went about mitigating each situation in a risk informed manner.

Liquid Filled Fuses

PG&E uses liquid-filled fuses throughout its service territory. These are fuses that PG&E stopped installing in 2006 as the liquid, which is there to extinguish the arc and dissipate the heat during a fault, is classified as a hazardous material.

These are exempt fuses[22] with no systematic program in place for replacement. PG&E stated that it is unaware how many LFFs are in service, and where the LFFs are located, as these fuses are not an attribute in the geographical information system (GIS), and there is insufficient data on these fuses in its base fuse dataset.

If the liquid in the fuse is gone or low, PG&E indicates there is a higher risk of ignition. Fuses are responsible for approximately 8% of historical equipment-related ignitions. From 2021

[21] Ignition 20241704

[22] CAL FIRE defines "exempt fuses" as current-limiting, non-expulsion fuses that contain arcs and hot gases internally, minimizing wildfire risk; these are exempt from vegetation clearance requirements under CCR Title 14 § 1255(b)(10).

through to mid-2024 (the time the LFF issue was first brought to the attention of PG&E's Risk and Compliance Committee (RCC)), PG&E experienced three LFF-caused ignitions, versus 50 ignitions over the same period caused by other fuse types (note: ignitions relating to misoperating E-fuses are addressed below). Only one of these LFF ignitions occurred in HFTD, and one of the three had a pre-existing maintenance tag for an empty fuse.[23]

With the increase in the use of aerial drone inspections over the past two years, PG&E began to detect 'no-liquid' and 'low liquid' conditions in these LFF with greater frequency. PG&E's initial inspection guidance was to create a priority B tag (90-day) to replace LFF with low (more than 1.25 inches of unfilled liquid at the top of the glass tube), missing, or undetermined liquid level in HFTD, and to issue a priority E tag (1-year) to replace LFF with the same conditions in Non-HFTD areas.

PG&E stated that while they may have historically had 100 open tags relating to no/low liquids at any time across its service territory, the recent increase in distribution aerial inspections resulted in approximately 6,800 new B tags being created in 2023 and 2024. PG&E stated that this surge in LFF B tags resulted in higher risk tags being potentially deferred in place of lower risk fuse replacements.

In order to address this situation, PG&E implemented several changes in August 2024. PG&E authorized a revision to the overhead job aid to change the tag priority from B to E in HFTD, with inspectors required to add a notation to the tag long-text if the liquid level was less than 50%. If the fuse is cracked or otherwise damaged, then the tag may escalate to a higher priority. In addition to this guidance change, PG&E allowed the original B tags identified in 2023 and 2024 that were still open to be reclassified as E tags. As an additional layer of control, the RCC also authorized that pole clearing[24] be conducted in the later part of 2024 at approximately 2,200 of the original open B tag locations with the highest wildfire consequence (representing 79% of the aggregate wildfire consequence from these LLF tags), with the remaining 2,200 open original B tag poles pole cleared before the start of the 2025 fire season.

PG&E stated that it does not have any historical data on LFF degradation rates, or causes of liquid leakage, and that it was unsuccessful in gathering any equivalent data from the previous manufacturer, given how long it has been since PG&E last installed these fuses. In order to determine what liquid levels in the LLF might correspond to differing levels of risk, the RCC authorized ATS to conduct additional testing. Given that the liquid in the LFF is considered hazardous, a third-party testing lab capable of handling the materials was identified, and PG&E notified the ISM that the test results have just been received by ATS. PG&E indicated that it will present updated guidance on liquid levels and replacement tag priority to leadership and the ISM when ATS completes its assessments.

[23] The pre-existing tag for this 8/7/2023 LFF ignition was dated 07/01/2023, so the B tag (90-day deadline) was not overdue at the time of the ignition. Of the three LFF ignitions, one was listed as damaging PG&E equipment only, one reported a fire spread between one and three meters, and one reported a fire spread between three meters and 0.25 acres.

[24] The clearing of vegetation in a ten-foot radius around the base of the pole.

E-Fuses

PG&E uses expulsion fuses or "E-fuses" in its electrical operations. In a normal operation, a fault causes the fuse element to melt, which causes an actuating spring to retract an arcing rod into a boric acid tube that is designed to snuff out the electrical arc. If the boric acid absorbs water, it swells, preventing arcing rod movement, creating a misoperation. If this happens the failed fuse will 'candle' and burn in half near the fuse element.

E-fuses are the only PGE-approved line fuse for a cutout that is EPSS compatible and CAL FIRE exempt from vegetation clearing. E-fuses are also used in WMP commitments for the Non-Exempt Fuse Replacement Program. PG&E currently has approximately 80,000 E-fuses in service on primary distribution main lines.[25]

PG&E identified approximately 100 known E-fuse misoperations between 2010 and 2023, noting that not all misoperations lead to ignitions. At the time the ISM first became aware of the situation in 2023, PG&E was reporting an increase in the annual number of E-fuse ignitions, with 12 failed fuses resulting in 10 ignitions in 2022 (3 CPUC reportable, one of which occurred in HFTD) and 19 failed fuses in 2023 resulting in 16 ignitions (6 CPUC reportable, four of which occurred in HFTD). PG&E did not record any ignitions in 2024 and during the first seven months of 2025.

To identify the root cause of the water intrusion into E-fuses, ATS undertook a series of investigative steps, which included:

- Investigation at the supplier factory line, with no observations of how the boric acid could be compromised in the assembly process.
- Benchmarking with another utility, which confirmed that 1) E-fuses were the other utility's primary fire exempt line fuse, 2) the other utility had not seen a failure in 15 years, and 3) that the other utility's truck stock was stored in the original factory materials (inside plastic bags and stored in boxes).
- Testing was done on 151 fuses stored at PG&E's remote material stock with no compromised fuses identified.

PG&E finally identified the cause of the issue as the storage of E-fuses in truck stock boxes without their original manufacturer equipment packaging. Working with technicians from the supplier, PG&E tested approximately 560 fuses from trucks at 14 yards. Some of the storage boxes showed condensation on the lids and rust from standing water in the truck boxes. PG&E stated that 1) approximately 1.3% of the sampled fuses had full boric closedown and would likely have burnt instead of clearing a fault, and 2) approximately 30% had visual evidence of water ingress (partial boric closedown) that likely would have cleared a fault, with some not dropping open out of cutout. The testing found that the water intrusion occurred only in E-fuses removed from their original equipment manufacturer packaging.

Following this root cause evaluation, PG&E undertook the following steps. A Critical Product

[25] In addition to E-fuses on primary distribution lines, E-fuses are allowed to be used for equipment protection on transformers, pad mounted heavy switchgear, in substations etc. PG&E states that these are less common, and that fuses protecting this equipment are not currently mapped and cannot be accurately counted at this time.

Newsflash was executed in February 2024 and a Transportation Services Bulletin was created for Trouble Truck fuse boxes. PG&E also purged all stocks of its E-fuses that had been improperly stored.

PG&E performed the following additional measures to mitigate its E-fuse risk following the purge of E-fuses in 2024 that did not conform to storage practices:

- Targeted replacement of e-fuses at approximately 1,400 of the highest scoring wildfire consequence poles.
- Targeted vegetation clearing at locations with elevated wildfire consequence and where the pole was exempt from pole clearing regulations.
- Development of a field verification form to help track when line workers replace E-fuses. The form requires affirmation of replacing all phases and using fuses from Original Equipment Manufacturer (OEM) packaging.
- Integrated truck audits for the Electric Distribution Operations and the Restoration teams for E-fuse storage conformance.
- Completed testing by ATS of E-fuses from other manufacturers, to evaluate performance and ability to prevent water ingress into the fuse.
- Upgraded OEM packaging by increasing the internal packaging bag thickness to prevent water ingress in case packaging box is deteriorated.

Circuit Board Replacements

In December 2024, an equipment supplier informed PG&E that one of their controllers, which PG&E began using in their line reclosers in 2019, had a faulty circuit board that could cause inadvertent opening and closing of the recloser without prompts. The supplier communicated that the root cause was a faulty diode that put their pre-2024 units at risk. The supplier notified PG&E that it was changing its diode supplier and would be using an over-designed diode in the new replacement boards to prevent future in-service failures.

PG&E previously tracked unprompted operation of these reclosers six times from the date they began to be installed, with the first noted in January 2022, but was unable to attribute a cause. PG&E informed the ISM that ATS/AFA were not involved in investigating any of these incidents, but that there was a belief that the misoperation was caused by water intrusion into the recloser. PG&E further informed the ISM that these six incidents did not result in any ignitions.

Shortly after learning of this issue, PG&E issued a Safety Flash in January 2025. Until the defective units are replaced, PG&E gave guidance that the troubleshooter or lineman shall be dispatched to manually open all phases after the line recloser is opened and again before the recloser is closed. PG&E stated that if a line recloser operates without prompt on an EPSS line, the risk period is the length of time it takes PG&E personnel to be on site for the manual adjustment. PG&E informed the ISM that for any circuits with the defective controllers, under higher risk conditions, PG&E could open the upstream SCADA device when the EPSS recloser device trips, and to keep the device open until the troubleshooter physically arrives on site.

The ISM observed that as of April 2025, PG&E had approximately 2,600 of these controllers in-service across 19 divisions. Of these, PG&E deemed approximately 1,300 units as EPSS Important, denoting the units' importance to EPSS's planning as it protects an HFRA/HFTD area. In addition to its in-service devices, PG&E also identified approximately 400 additional units in inventory.

PG&E made arrangements with the supplier to receive approximately 200 replacement units with the new diodes per week starting in late April 2025. By the end of the third week of August, PG&E received the last of the units needed for full replacement of its in-service units. PG&E informed the ISM that neither the recloser nor the controller need to be replaced, and that only the board located inside the controller needed replacement. The powerline did not need to be de-energized to perform this in-field replacement, but the sequence did require switching and operations support.

The supplier initially conducted board replacement training for the assigned PG&E field teams to maintain warranty, and the in-field replacements began the week of April 28. By mid-September, PG&E replaced approximately 2,200 of the 2,600 units, with the completed replacements covering 100% of those deemed EPSS Important.

The ISM observed that in developing the workplan for the board replacements, PG&E utilized a risk ranked approach on a circuit level to allow the field teams to more efficiently address the replacements in an area. The prioritization was based on conductor level risk, aggregated for the targeted circuits, along with the prioritization of PSPS devices. The highest priority circuits located in southern divisions were the first to be remediated.

In June 2025, PG&E reported an unprompted operation at a line recloser which had its board replaced two weeks earlier. The supplier investigated this unit and issued a preliminary report in July which confirmed that no commands to open the phase were issued by the controller, and that the observed issue was not related to the diodes. PG&E and the supplier are currently reviewing other possible causes of this inadvertent operation.

FAST TRIP PROGRAM UPDATES

PG&E's EPSS program remains a key wildfire mitigation measure, rapidly de-energizing power lines when conditions that can lead to ignitions are detected. In ISM Previous Reports, the ISM reported on the initiation and maturing of the EPSS program since its inception in 2021, and on the expansion of EPSS enabled lines to their current 44,000 distribution miles covering approximately 1.8 million customers. As previously reported, PG&E stated that under weather normalized R3+ FPI conditions, its EPSS program showed a 65% ignition reduction effectiveness in 2024 when compared to the pre-EPSS 2018-2020 period.

EPSS Program and Trends

PG&E's EPSS group experienced a leadership change in 2025, with the current Director being the third to hold this position since the start of the ISM engagement in 2022. The EPSS team is currently comprised of fourteen full-time employees, and is in the process of expanding. The ISM observes the group's weekly operating reports and observes select EPSS weekly group meetings.

Table 3 provides an overview of EPSS performance over the January to July 2025 period, versus the same seven-month period from 2022 to 2024. As seen in this table, the number of EPSS outages during the first seven months of 2025 have been the highest versus comparable prior periods. This is due to EPSS fire season enablement (established using environmental criteria outlined in ISM Previous Reports) having started several weeks earlier than in prior years, with some EPSS enablement also occurring in the southern portions of PG&E's service territory during the first quarter of 2025. This additional enablement as a result of the earlier start to higher risk fire conditions, can be seen in the elevated 2025 figures for EPSS total circuit days, total circuit-mile days (CMD) and total customer minutes enabled (CME).

Table 3: EPSS Data: January to July 2022 to 2025

	Year to Date (January to July)			
	2022	2023	2024	2025
EPSS Enabled Circuit-Days	44,163	29,243	43,228	54,876
EPSS Enabled Circuit Mile-Days	2,474,990	1,696,891	2,423,628	3,025,352
EPSS Customer Minutes Enabled (CME, billions)	112.4	70.0	109.3	140.9
EPSS Outages	964	731	1,108	1,186
EPSS Outages per 10k CMDs	3.89	4.31	4.57	3.92
EPSS Outages per 1B CME	8.6	10.4	10.1	8.4
Reportable Fire Ignitions on EPSS Enabled Lines	17	7	22	10
RFIs per 10k CMDs	0.07	0.04	0.09	0.03
RFIs per 1B CME	0.15	0.10	0.20	0.07
EPSS CAIDI (min)	181	204	156	141
Average EPSS CESO	884	943	835	780
Restored < 60 minutes	8.9%	11.8%	16.8%	20.5%
Total Customers Experiencing EPSS Outages	852,179	689,082	925,215	925,505
Outage Cause (% of total)				
3rd Party	9.3%	9.6%	9.5%	10.3%
Animal	16.5%	14.1%	11.6%	15.8%
Company Initiated	3.9%	8.5%	11.5%	13.5%
Environmental/External	0.5%	1.5%	1.5%	2.0%
Equipment	12.8%	14.8%	13.4%	14.6%
Unknown	44.5%	39.8%	39.0%	32.5%
Vegetation	12.4%	11.8%	13.5%	11.3%

While PG&E experienced the highest number of outages on EPSS enabled lines in the first seven months of 2025 versus comparable periods since EPSS enablement first began, the first seven months of 2025 also saw a significant drop in the number of CPUC reportable fire ignitions (RFI). The 10 RFI experienced during the first seven months of 2025 dropped from 22 experienced over the same period in 2024 (many of which occurred during the record temperatures of July 2024). PG&E's normalized RFI per ten thousand EPSS enabled circuit mile days of 0.03 in 2025 was one-third the rate during the same seven-month period in 2024, and the lowest since EPSS enablement began.

The ISM detailed PG&E's efforts at reducing the average customer duration of EPSS outages

(CAIDI) in ISM Previous Reports.[26] PG&E's efforts at reducing the average duration of EPSS outages (CAIDI) since 2023 include PG&E's use of its storm outage prediction model to better station its staff for post-storm restoration work and patrols, and increased use of fault detectors and continuous monitoring (CM) devices to help narrow patrol locations. In addition to CAIDI dropping approximately 31% over the past two years, PG&E's percent restorations within 60 minutes also increased from a low of 8.9% for the first seven months of 2022 to 20.5% for the same period in 2025.

PG&E's continued expansion of its line sectionalizing program also assisted in reducing customer impacts. Expanded sectionalization helps isolate an EPSS outage to shorter circuit segments, which in turn allows for faster restoration of service for more customers. In addition to the 209 sectionalizing devices that were installed by the end of 2023, PG&E added 186 devices in 2024, and an additional 55 devices during the first seven months of 2025. An additional 82 sectionalizing devices are planned to be installed by the end of 2025. This additional sectionalization also provides the benefit of reducing the customer footprint for EPSS outages, with the average number of customers experiencing a sustained outage (CESO) dropping 12% over the past three years, from 887to 780 customers/outage.

Since EPSS negatively impacts PG&E's overall reliability, there could be an incentive for skipped or shortened patrols before re-energizing a tripped circuit. For this reason, the ISM reviews the circumstances behind some of the most rapid power restorations each reporting period with EPSS leadership. In approximately 20 instances, the ISM observed that the restorations appeared to be conducted in compliance with PG&E's policies and guidelines.

PG&E reduced its historical 40% level of outages attributed to "Unknown" causes down to 32.5% in 2025. The ISM documented PG&E's efforts to improve its outage cause determination in ISM Prior Reports[27] (including the use of new Gridscope devices further detailed in the following section). PG&E stated that improved causation data allows it to better target mitigations or fine tune device setting to further reduce customer impacts in the future. PG&E also stated that many of the Unknown outages may be due to vegetation or bird contact, where a striking branch or bird may not be found during a patrol. As seen in Table 3, the drop in the percent of Unknown caused outages corresponds closely to the percent increase in identified bird-caused EPSS outages in 2025.

The ISM observed Company Initiated outages on EPSS enabled lines increase from 38 (3.9%) in the first seven months of 2022 to 160 (13.5%) in the first seven months of 2025.) PG&E noted that although the figures indicate an increase, PG&E is not certain that the numbers actually increased. PG&E stated that at the onset of the program, EPSS tripping during planned outage activities was often not immediately reported, and that its crews were sometimes unaware that their work initiated an interruption to more customers than anticipated. The patrol and response activities resulted in the outage cause being categorized as Unknown, rather than Company Initiated. PG&E further stated that it instituted practices in May 2024 to ensure crews test conductors at the switching locations, ensuring any unintended tripping is

[26] ISM Report 3, pg. 12; ISM Report 4, pg. 17; ISM Report 5, pg. 14; ISM Report 6, pg. 18

[27] ISM Report 2, pg. 21; ISM Report 3, pg. 12; ISM Report 4, pg. 17; ISM Report 6, pg. 18

immediately reported to the Distribution Control Center (DCC), allowing safe and rapid restoration and proper documentation of the cause of the outage.

EPSS Outage Reduction Mitigations

PG&E has been implementing two programs over the past two years designed to reduce the number of vegetation and animal contact EPSS outages. PG&E's Vegetation Management for Operational Mitigation (VMOM) and its Animal Mitigation programs were described in ISM Report 6,[28] and are designed to conduct proactive vegetation work and to proactively install new animal mitigations on EPSS enabled circuit segments that historically experienced higher frequency of these two types of outages. Further information on the VMOM program and the circuit selection eligibility criteria are discussed later in Vegetation Management section.

PG&E installed 132 animal mitigations in 2023 on EPSS lines and added an additional 1,840 animal mitigations in 2024. Of the 3,000 animal mitigations PG&E plans to install in 2025 under its Avian Protection Plan, PG&E is currently targeting approximately 1,800 of these on EPSS enabled circuits which experienced more frequent historical animal-caused outages.

In discussions with EPSS leadership, the ISM observed that the 2025 Animal Mitigation program started later than originally anticipated. While the 2024 animal mitigations created their maintenance tags in the fourth quarter of 2023, allowing the mitigations to be installed earlier in the year, the maintenance tags for the 2025 animal mitigations were not ready by the start of the year, and are still in the process of being created. Work on the 1,800 targeted mitigations started in August, with PG&E indicating that the work is expected to be completed by the end of October 2025. PG&E also informed the ISM that the EPSS team intends to work with the Asset team to ensure that maintenance tags for the 2026 animal mitigations are created early. Leadership also indicated that maintenance staff needed for these installations were diverted to the controller replacement program (described in the Equipment Investigations section).

In an attempt to reduce the impact on customers experiencing multiple EPSS outages, PG&E also introduced a new pre-season drone patrol program, and provided more of its impacted customers with in-house batteries.[29] The 15 circuits selected for its pre-season patrols were the circuits with the highest number of 'Unknown' caused EPSS outages. The original intent of the program was to use aerial drone inspections to identify A, X and B tag conditions prior to the start of peak fire season. EPSS leadership indicated that the program got off to a later than planned start due to resource and scheduling issues. Since the EPSS team relies on the inspections group for drone image captures and reviews, PG&E did not schedule these pre-season-patrols until later in the year, given higher priorities assigned to planned WMP inspections and aerial Comprehensive Pole Inspections on assets to be included in 2025 mega-bundling of maintenance tags, These patrols are now expected to be completed in September 2025. EPSS leadership indicated that it is working with the Asset Strategy group, which

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[28] ISM Report 6, pg. 19

[29] 1,193 batteries were installed through August 28, 2025, with an end of year target of 1,500, versus 1,446 batteries installed in 2024 and 443 installed in 2023.

coordinates the drone inspections, to ensure that these patrols can be performed prior to peak fire season for 2026.

EPSS Expansions

Following the 2025 Southern California fires, PG&E's senior leadership asked the EPSS team to review the EPSS Buffer Areas. These Buffers are selected to try and reduce ignitions that possess the potential to start outside HFRA but spread into these higher risk areas. In general, these Buffers are only enabled during periods of high wildfire risk, with enablement occurring less frequently than in HFRA. Distribution circuits are EPSS capable on 44,000 miles currently covering 100% of the HFTD plus approximately 19,000 Non-HFTD area miles.

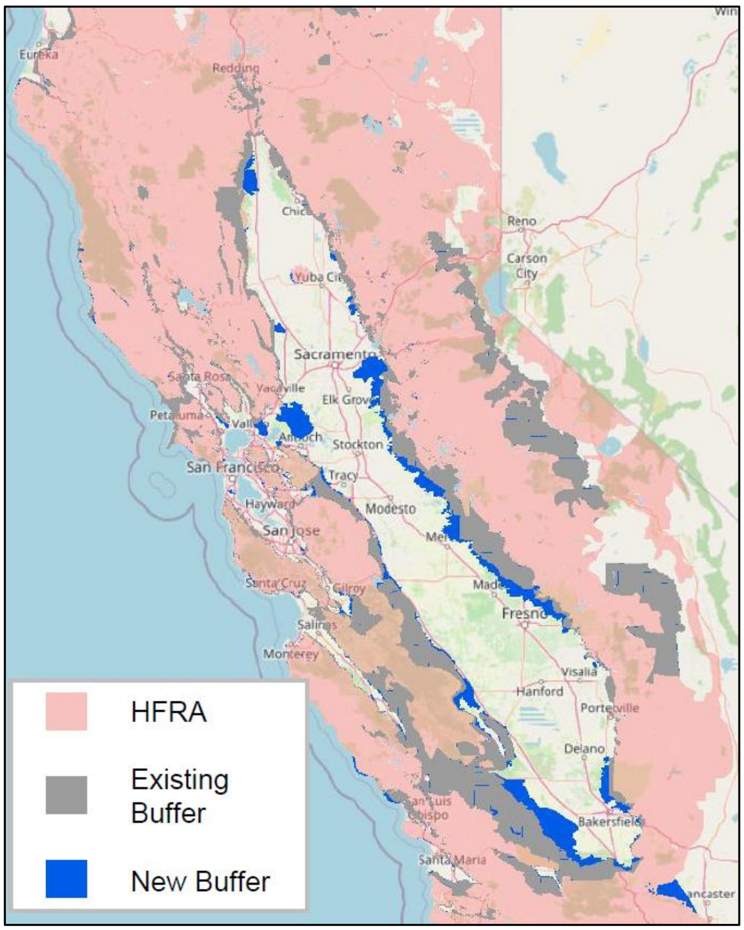

Figure 7: PG&E Existing Buffer and 2026 New Buffer Expansions

Figure 7 shows the location of PG&E's existing Buffer Area plus the areas of proposed expansion. Using the 2025 Buffer Area polygon additions from its re-evaluation modeling, PG&E identified 300 new EPSS devices to add across an additional 128 circuits (approximately 3,300 additional line miles), adding approximately 193,000 additional customers to the approximately 800,000 customers currently in the Buffer Area. PG&E plans to have these additional Buffer Areas EPSS enabled before the start of the 2026 fire season.

In addition to its distribution system, PG&E continued its expansion of EPSS capability on an additional 14 transmission circuits in 2024, covering a total of 768 miles. As detailed in ISM Report 3, not all of the 525 transmission lines traversing HFRA are eligible for EPSS implementation. By the end of August 2025, PG&E completed EPSS enablement on an additional seven transmission lines (bringing the total to 61 circuits), with an additional six planned for the remainder of the year. PG&E has indicated that remaining large lines are currently being reviewed for feasibility of EPSS implementation.

Downed Conductor Detection

DCD uses electrical sensor information and software to identify the presence of specific electrical characteristics (i.e., signatures or patterns) produced by conductors contacting the earth's surface, thus initiating trips on circuit interrupting devices. DCD is complementary to EPSS since DCD is designed to identify high-impedance (low current) faults, which may be difficult to detect through EPSS or conventional fault detection schemes.

PG&E continued to expand its DCD capability in 2024, adding 655 DCD line recloser devices to the 1,129 devices previously installed, and 40 DCD circuit breaker devices. PG&E installed 330 new line recloser devices (exceeding its target of 250) and 36 new DCD circuit breaker devices (meeting its target of 36) in 2025, bringing the total DCD coverage to approximately 30,000 miles, with approximately 21,500 of these miles in HFRA, covering 85% total HFRA lines

PG&E continues to see DCD as a significant mitigation that can be used to supplement EPSS detection gaps. Of the 360 DCD outages in 2024, following post-outage patrols and investigations, PG&E identified 55 of these as having likely mitigated potential ignitions.

CONTINUOUS MONITORING (CM) PROGRAM

The ISM previously reported on several new CM technologies that PG&E started to deploy after the completion of its pilot programs. As PG&E's Gridscope, Early Fault Detection (EFD), Distribution Fault Anticipation (DFA) and Smart Meters technologies have been described in ISM Previous Reports, and are detailed in PG&E's Wildfire Mitigation Plans, Figure 8 provides a simplified description of these technologies and their benefits.

SmartMeters	Gridware Gridscope	Early Fault Detection	Distribution Fault Anticipation
• AMI 1.0 SmartMeters with Machine Learning (IONA / EDAPT) provide insights on transformers on the path to failure as well as ignition risks on secondary circuits (arcing, loose neutrals, wiring issues etc) • AMI 2.0 SmartMeters with Distributed Intelligence enable real-time data processing locally on the meter, enabling faster insight • EPIC 3.43 tested location awareness and phase identification, high impedance between meter panel and transformer secondary side	Gridscope devices provide continuous monitoring that advances wildfire safety and system resiliency: ▪ Identifying outage types & causes ▪ Providing expedited response to an outage to reduce restoration times and the likelihood of a wildfire ▪ Providing insights into equipment status and dispatching both construction crews and T-men only when needed ▪ Reducing operating costs by better targeting patrols ▪ Predicting the health of physical grid assets by monitoring environmental, wildlife, and physical stresses	Early Fault Detection (EFD) technology uses radio frequency (RF) sensors mounted underneath conductor to detect RF emissions caused by partial discharge associated with emerging electrical asset defects with approximately 30 feet locational accuracy By spotting early signs of equipment stress, we can prevent faults from escalation into outages and ignitions. Detection conditions types: ▪ Broken/damaged conductor/splices ▪ Broken/damaged insulator ▪ Tie-wire, bonding wire issues ▪ Failing service transformers ▪ Vegetation encroachment ▪ Fuse Cutout Malfunction	• Devices engineered and subsequently installed at the substation, typically one per circuit • DFA uses sensitive monitoring to detect subtle electrical precursors that signal impending line failures. • Works in concert with Line Sensors, SmartMeters, EFD • Detections include: • Fault Induced Conductor Slap • Arcing Underground Elbows • Series Arcing Benefits: ✓ Enhances reliability ✓ Prevents outages and wildfires ✓ Increases operational efficiency

Figure 8: Continuous Monitoring Technologies and Benefits

Asset Health Performance Center / Continuous Monitoring Center

PG&E's Asset Health and Performance Center (AHPC), which manages EFD, DFA, Line Sensors and asset monitoring using SmartMeter data, is in the process of taking over Gridscope deployment and monitoring from the EPSS group. The above technologies together constitute the current Continuous Monitoring suite.

AHPC is a department in Electric System Operations with approximately twenty full-time and contract employees. PG&E allocated funding for a new AHPC Continuous Monitoring Center (CMC) at a PG&E facility which is expected to be completed by the end of 2025. This new CMC will expand PG&E's situation awareness by being a complement to the Transmission and Distribution Control Centers, and the Hazards Awareness Warning Center and Meteorology Operations. PG&E's goals for its new CMC are to 1) monitor asset performance data and initiate proactive repair or replacement, 2) reduce wildfire risk via increased situational awareness of asset health and operating conditions, 3) improve safety by reducing the amount of time between when hazards develop and when PG&E is able to act, 4) restore outages more quickly via identification of likely fault location and generation of patrol zones to deploy the right crews to the right place, and 5) optimize investment strategies by augmenting PG&E's workplans with continuous performance data to deploy capital effectively.

Continuous Monitoring Technologies and Expansion Plans

Table 4 provides information on the EFD, DFA, Gridscope and line sensors that PG&E deployed through the end of 2024 plus current plans for continued deployment in 2025.

Table 4: Continuous Monitoring Deployment

Technology	EOY 2024 Installs		2025 Workplan		2025 WMP Commit	Covered Circuit Milage	
	Circuits	Locations	Circuits	Locations (net new)		EOY 2024	Planned 2025
Early Fault Detection	8	203	4	331	4 Circuits	654	815
Distribution Fault Anticipation	96	96	15	15	15 Circuits	12,063	1,895
Gridscope (in targeted circuit segments)	37	10,080	2	10,000	N/A	779	886
Line Sensors	298	1,296	45	243	40 Circuits	34,675	2,956

The ISM has not previously reported on PG&E's line sensors. PG&E uses a variety of line sensors, which are small electronic devices mounted directly on overhead distribution and transmission lines that monitor real-time conditions on the electric grid. These devices typically measure current every 15 minutes, and assist in detecting and locating faults. The data from PG&E's line sensors and DFA have been integrated into PG&E's Foundry platform, allowing for the data to be analyzed and the approximate area of possible fault or disturbance be calculated based on the circuit model impedance. By taking advantage of repeated events where the cause is "unknown," PG&E notes that its tools can use the accumulated data to better determine anomaly locations.

PG&E has also worked on additional IT integration of its Gridscope devices. While Gridscope alerts were initially emailed to dispatchers from the vendor after the signals were analyzed, PG&E recently completed the automation of these alerts in May 2025. These alerts now get captured into PG&E's Grid Data Analytics (GDAT) platform in Foundry, which then interfaces with the Advanced Distribution Management System which PG&E uses to monitor, analyze, and control its electric distribution grid in real time. The new system takes in the Gridscope alerts and creates unknown premise tags in the Outage Dispatch Tool, similar to a customer reported problem. This process can help dispatch PG&E personnel faster to more accurate locations, and possibly provide information on the type of incident, based on the type of signals the Gridscope device has detected.

The ISM has also observed PG&E's circuit selection methodology for the 2024 and 2025 Gridscope installations. These locations were chosen based on wildfire risk buydown curves and factoring in three-year histories for HFRA reportable fire ignitions and unplanned customer outage minutes, along with the number of pole and non-pole maintenance tags. The circuits selected for the 2025 Gridscope deployment cover three different programs, including the backfilling of two circuits that were partially completed in 2024, two circuits designated as Ignition Task Force Circuits (see Risk Tracking and Risk Reduction section for information on this task force), and two circuits identified under the Three Cycle Delay Pilot.[30] The 2025 deployment of Gridscope on these two circuits is intended to help reliability impacts that may be caused by the faster trigger.

Smart Meter Program Advancements

PG&E further advanced its Smart Meter technologies during the current ISM reporting period. Figure 8 referred to Advanced Meter Infrastructure (AMI) 1.0 Smart Meters working with PG&E's IONA and EDAPT models. The ISM observed the development of these models over the past two years, and PG&E internally circulates examples of 'good catches' (catches that are more predictive of upcoming failure), where smart meter data and EDAPT model interpretations led to prevented ignitions or key insights, each week.

IONA is a machine learning transformer failure prediction model designed to identify transformers with anomalies that could lead to outages or failures in the mid-term. The model is trained on historical data such as smart meter voltage and loading, weather, and transformer related outages/failures. To further increase the accuracy and quality predictions of the IONA model, PG&E recently re-trained the model using IONA's successful interventions from 2023 and 2024, as well as historical transformer failures that resulted in emergency tags. In addition, PG&E improved the workflow of IONA by implementing the following:

- created an auto-classification model for common cases predicted by IONA, such as transformers winding failures, neutral/grounding issues (broken, loose), and wiring issues.

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[30] PG&E noted that it is piloting a lower EPSS maximum allowed response time of three cycles instead of the present maximum of six cycles (1/10 of a second) on select circuits.

- linked detailed mapping of transformers and their associated service points.
- Implemented graphing enhancements including:
    - Transformers' ratings and maximum capabilities on load graphs
- Rule 2 boundaries on voltage graphs[31]
    - Highlighting weather events (high winds and temperature) on both usage and voltage graphs for easier correlation.

PG&E stated that these enhancements will increase the efficiency of engineering desktop reviews, allow for less transitions between different tools, and prioritize critical voltage anomalies.

PG&E's Transformer Overload Accuracy Model (TOAM) is a physics-based algorithm which estimates the voltage drop, phasing and impedance characteristics across primary and secondary distribution transformers. Anomalies in the voltage drop and impedance can indicate various data quality errors and operational conditions. PG&E stated that it leverages this tool to identify data quality errors in transformer ratings, customer connectivity, and metering issues. PG&E also leverages TOAM to identify operational issues such as unmetered load, energy theft, and overloaded secondary/service panels. Because this tool and IONA sometimes identify different issues, they are used as an ensemble forecast to improve performance. The Electric Distribution Analysis & Prediction Tool (EDAPT) is a Foundry workflow implementation that combines IONA and TOAM and provides an operational process that is used by the AHPC for CM and dispatch as a response to these anomaly detections.

AMI 2.0 meters possess technology that enables these meters to sense degradation of certain assets both behind the meter and in front of the meter. PG&E stated that it intends to gradually replace its AMI 1.0 meters with AMI 2.0 meters, either through AMI lifecycle replacements, targeted installations for wildfire risk reduction, and/or use cases that deal with accelerating electrification as noted in the company's 2027 General Rate Case filing.

The EPIC[32] 3.43 project referenced in Figure 8 utilized Itron Riva meters (AMI 2.0) in a small field pilot area (~400 meters) to determine if edge computing platforms could provide grid edge details and insights. The pilot included two applications on the meter. The applications were (1) Location Awareness (LA), which determines a meter's primary and secondary connectivity associations, including meter to transformer mapping and phase ID/referencing, and (2) High Impedance Detection (HID), which detects conditions where impedance between service transformer and customer service point (socket) are above normal levels, indicating a connection issue. PG&E noted that both applications performed well, providing very accurate connectivity mapping (LA) and identification of several safety risk connections issues.

Continuous Monitoring Benefits

With the continued deployment of these CM technologies, the ISM observed PG&E beginning

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[31] Under Rule 2, the standard service voltage must remain within: ±5% of the nominal voltage during normal operating conditions, and ±10% of the nominal voltage under adverse conditions (emergencies, switching, etc.)

[32] Electric Program Investment Charge or EPIC is a program to fund public-interest R&D, demonstration, and deployment projects that advance clean energy, grid modernization, and safety.

to track several CM-derived risk and cost reductions. PG&E noted that with less than 1,000 miles of CM deployed, a statistically relevant ignition reduction will take multiple wildfire seasons/years to determine. PG&E also noted that individual potential ignitions mitigated can be identified from post event patrols and inspections.

PG&E identified nine potential ignitions mitigated in 2025 (one Gridscope, six EDAPT/Smart Meters, one EFD and one DFA).[33] PG&E also publishes weekly lists and photo examples of 'great catches' (a timely catch that caught a potential failure immediately before it may have occurred) and good catches.

PG&E started to quantify reliability benefits from some tag repair rescheduling and arising from more targeted fault location through its CM deployments. Through the end of July 2025, PG&E identified 515 Gridscope, 94 EFD/DFA, and 380 program-to-date alerts that translated into reliability benefits. PG&E is in the process of defining and calculating various cost saving benefit types, such as Find & Fix (PG&E field personnel fix the situation themselves without a need to call or schedule a follow-up crew), Find and Schedule (B tag finds), Find and Repair (A and X tag finds), Patrol Cost savings and CAIDI reduction savings. For the first two Find-categories, PG&E currently estimates approximately $4 million in savings from the beneficial program-to-date alerts. Savings are still being determined from the other three categories.

RISK AND MITIGATION PRIORITIZATION MODELS

The ISM discussed the refinements of PG&E's wildfire risk models over the past five years in the ISM Previous Reports, including details on enhancements incorporated into the Wildfire Distribution Risk Model Version 4 (WDRM v4) and the Wildfire Transmission Risk Model Version 2 (WTRM v2). PG&E did not bring forward any new interim, WDRM or WTRM iterations for approval during the current ISM reporting period. PG&E notified the ISM that it intends to make decisions on future logic or component modification to WDRM v5 and WTRM v3 in 2026.[34]

During the current ISM reporting period, PG&E presented updates to its PSPS guidance (v5.5), its 2025 transmission Operability Assessment (OA) model, and a new version of its Wildfire Cost Benefit Analysis Model v2.0 to the ISM, with model updates detailed below.

Fire Science and Distribution Public Safety Power Shutoff Models Version 5.5

In ISM Report 5, the ISM provided details on the suite of models that encompass PG&E's FPI 5.0 and its distribution PSPS guidance models 5.0.[35]

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[33] The ignitions mitigated are through October 10, 2025, with the EDAPT and EFD ignition reviews since May 1. Examples of ignitions mitigated can include vegetation in contact with an energized line, failure at the bottom of a pole with the pole floating and held up by the wires, energy theft and unauthorized wiring.

[34] PG&E notified the ISM that the inputting of the prior year's data is being undertaken for its fire science and WTRM model but not for its WDRM model which is done a three-year cycle.

[35] The models in the PSPS 5.0 guidance include the Outage Probability Weather Model (OPW 5.0), the Ignition

During the current ISM Reporting Period, PG&E updated its FPI model to version 5.5 due to changes in PG&E's Operational Mesoscale Modeling System (POMMS) model, which incorporates the prior year's meteorological and fire data. While PG&E's Wildfire Risk Governance Steering Committee (WRGSC) approved the new POMMS v4.0 model for use on August 1, 2025 PG&E stated that it will operationally run the POMMS v3 and PSPS 5.0 model as a back-up/reference for the balance of 2025, given the importance of these models for predicting and guiding PSPS events.

Recalibration of the PSPS models to ensure that the current guidance captures the relevant historical fire events resulted in only two changes to the minimum conditions required to consider a PSPS event.[36] As a result of these minor changes, the recommended guidance from PSPS v5.5 does not materially change the frequency, duration, or customer impacts compared to the PSPS v5.0 models and guidance. When back casting v5.0 and v5.5 guidance on the fifteen largest PSPS events from 2008 to 2024, as seen in Table 5, the updated guidance recommended larger customer counts nine times and smaller customer counts six times, with the net changes from all fifteen events representing a 3% increase in recommended customer counts. The projected event durations were also impacted by the updated model, (four longer, three the same, and eight longer) with customer minutes interrupted per event seeing seven events higher and eight events lower, with the net changes from all fifteen vents also representing a 3% increase in cumulative customer minutes impacted. PG&E also performed over 1,500 simulated PSPS events from 2017 to 2024, and noted that its change in V5.5 PSPS guidance would have resulted in the PSPS event count over this period increasing from 15 to 17.

Table 5: PSPS Guidance V5.0 Versus V5.5: Largest 15 Events 2008-2024[37]

PSPS Event Date	PSPS 5.0 Distribution Customer Counts	PSPS 5.5 Distribution Customer Counts	PSPS 5.0 Distribution Event Duration (hours)	PSPS 5.5 Distribution Event Duration (hours)	PSPS 5.0 Distribution Customer Minutes	PSPS 5.5 Distribution Customer Minutes
10/26/2019	294,359	293,443	35	34	618,153,900	598,623,720
9/7/2020	190,530	198,533	44	56	502,999,200	667,070,880
10/8/2017	192,899	194,365	34	31	393,513,960	361,518,900
10/13/2018	135,017	141,401	54	37	437,455,080	313,910,220
10/25/2020	135,117	137,405	28	31	226,996,560	255,573,300
11/7/2018	93,520	108,279	34	35	190,780,800	227,385,900

given Outage Probability Weather Model (IOPW 5.0), the Ignition Probability Weather Model (IPW 5.0) = OPW 5.0 x IOPW 5.0, and the Catastrophic Fire Probability Distribution (CFPD 5.0) Model = IPW 5.0 x FPI 5.0, which were detailed in ISM Report 5 and in PG&E's 2025 Wildfire Mitigation Update (April 2025, Section ACI PG&E-23-25).

[36] The guidance for the Fire Potential Index - Probability Catastrophic changed from >0.22 in v5.0 to >0.20 in v5.5, and the Catastrophic Fire Probability guidance changed from >7 in v5.0 to >6 in v5.5. PG&E made these adjustments as part of its recalibration to ensure that certain historical wind driven catastrophic events continued to be in-scope.

[37] PG&E selected 2008 as the starting year of its historical back casting as this was a significant fire history year in California, and this was the first year with complete location data in the Integrated Logging and Information System for unplanned outages.

10/3/2013	74,465	92,729	42	41	187,651,800	228,113,340
10/9/2019	78,556	70,194	41	40	193,247,760	168,465,600
10/11/2021	56,216	66,897	15	15	50,594,400	60,207,300
10/23/2019	64,364	61,517	20	19	77,236,800	70,129,380
9/27/2020	52,428	60,467	27	38	84,933,360	137,864,760
10/29/2019	65,287	56,853	31	30	121,433,820	102,335,400
10/14/2017	33,623	36,859	22	21	44,382,360	46,442,340
10/15/2020	36,889	35,590	35	35	77,466,900	74,739,000
6/10/2008	37,108	31,105	26	26	57,888,480	48,523,800

PG&E's transmission PSPS guidance is generated by a separate suite of models. The ISM expects updates to that guidance, based upon the new POMMS v4.0 weather model, to be presented for PG&E approval in the next ISM reporting period.

2025 Operability Assessment Model Improvements

PG&E maintains two transmission risk models, 1) its OA model, used in PSPS planning, and which looks at single hazard probability of structure failure against wind speed gusts, and 2) its Transmission Composite Model (TCM) which is a multi-hazard model used in transmission line asset strategy planning.

The OA model underwent numerous upgrades to align it with the enhancements of the TCM. These enhancements include the discontinuation of condition codes from enhanced visual inspections (detailed in ISM Report 6), and consideration of outages at component grouping level. PG&E approved two additional OA model modifications in August 2025.

The first change, following a December 2024 wood pole failure incident, adds pole load calculations to the model to account for potentially reduced safety factors of wooden poles. This is a change from OA 2024, where location ratio values from PG&E's pole loading calculation models were being used.[38] PG&E noted that this data was not always available for many structures, and could under-estimate the remaining strength for wood poles.

The second change is the manner in which pole test & treat (PTT) data was brought into the model. In OA 2024, PTT data came from the contractor historical records which required complicated data engineering to create harmonized datasets for the OA model. OA 2025 instead pulls the data directly from PG&E's SAP[39] system for a more streamlined and harmonized data ingestion.

Since the OA model is used in PSPS scoping, PG&E looked at how the model updates affect PSPS scoping using specific wind speed and FPI levels. The modeling found fewer structures from a larger number of lines in-scope using OA 2025. PG&E's conclusions from its analysis were that "Overall conservatism remains consistent between OA 2024 and OA 2025; the key difference

[38] A location ratio value is a normalized way of describing a position between two poles, where 0 is the starting structure, 1 is the ending structure.

[39] SAP (Systems, Applications, and Products in Data Processing) is an enterprise resource planning software suite that integrates business processes across departments (finance, supply chain, HR, procurement, asset management, customer service, etc.)

is that recent enhancements have enabled OA to apply that conservatism more precisely."

Wildfire Benefit Cost Analysis (WBCA) version 2.0[40]

During the current ISM reporting period, PG&E approved the use of its updated WBCA v2.0 model. PG&E uses its WBCA tool to calculate wildfire mitigation effectiveness at the circuit segment level. WBCA incorporates effectiveness values for each mitigation and combinations of mitigations by evaluating how successful each of them would be in mitigating a potential ignition risk resulting from particular combinations of unplanned outage events and equipment attributes ("outage combinations").[41]

Using historical data and subject matter experts (SME), PG&E assessed the effectiveness of each of the mitigation alternatives against more than 2,700 outage combinations that occurred in PG&E's HFTD areas during wildfire season. To determine circuit segment-level mitigation effectiveness, the WBCA adjusts for ignition risk sub-drivers on a given circuit segment based on the WDRM, their estimated frequency, and their contribution to overall risk on the circuit segment.

WBCA 2.0 can calculate both the Net Benefit[42] and the Benefit Cost Ratio of each potential mitigation. Figure 9 provides the formulas for each of those calculations.

Net Benefit	Benefit Cost Ratio
Net Benefit = **(Total Lifetime Benefits – Total Lifetime Costs)** *Net Benefits = (Wildfire Risk + Public Safety + Reliability) - (Lifetime Costs + O&M Costs + Vegetation Management Costs)*	**Benefit Cost Ratio =** **(Total Lifetime Benefits / Total Lifetime Costs)** *BCR = (Wildfire Risk + Public Safety + Reliability) / (Lifetime Costs + O&M + Vegetation Management Costs)*

Figure 9: Net Benefit and Benefit Cost Ratio Calculations

In addition to updating the WBCA 1.0 data sets, WBCA 2.0 incorporates data from the Outage Program Reliability Risk Model updated mitigation benefit periods and asset life, and rebuilding costs for overhead assets.

The new Outage Program Reliability Risk Model calculates the financial impact to customers from projected EPSS and PSPS outages. These projected customer impacts serve as the baseline from which any reliability savings that can reduce EPSS and PSPS exposure (such as the

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[40] This section reflects PG&E's reported methodology, assumptions, and conclusions regarding its Wildfire Benefit Cost Analysis (WBCA). PG&E's methodology and assumptions related to this model may not align with forthcoming regulatory guidelines.

[41] Examples of outage combinations are: 1) Company Initiated/Improper Construction, Primary Distribution, Deteriorated, 2) Vegetation, Tree – Branch Fell on Primary Line, Anchor or Guy, Broken, 3) Animal, Squirrel, Primary Overhead Conductor, Burned/Flashed.

[42] Net Benefit is not required by any Commission Decision and its use in decision-making is still subject to litigation at the Commission.

undergrounding of overhead lines) can be added to the Benefits side of the formulas in Figure 9. This model is composed of two components:

- EPSS Reliability Risk Model: This model considers which EPSS enabled asset failed and its upstream device, to assign the number of respective customers impacted downstream of the device. It is based on the number of unplanned EPSS-related outages 2022 to 2024 versus a 2017 to 2020 baseline. The EPSS Reliability Model calculates the risk based on customer minutes interrupted multiplied by the value of service and subtracts off the risk of normal 'blue sky' outages that would have occurred regardless of EPSS enablement.[43]
- PSPS Reliability Risk Model: This model is based on PSPS historical lookback data from 2018 to 2024. The model uses customer criticality to distribute risk percentages, and output is calibrated against the PSPS bowtie model,[44] which estimates approximately $1.6 billion in distribution PSPS risk annually.[45] This model calculates risk based on probability multiplied by customer minutes interrupted for each 0.7 square kilometer polygon projected to experience a PSPS event.

PG&E also shifted the hosting of WBCA 2.0 to its Foundry platform, allowing for greater accessibility and functionality, with the latest model also incorporating upstream and downstream impacts.[46]

PG&E stated that WBCA 2.0 supports calculating inputs in its Integrated Planning Underground Tool Development (IPUTD) suite. IPUTD tools enable circuit segment analysis and selection, project design and portfolio management across PG&E's electric grid infrastructure programs such as undergrounding, system hardening, and capacity planning. WBCA 2.0 does not result in any decisions, but calculates initial benefit cost ratios as part of iterative decision trees used to support system hardening mitigation selection for the following proceedings:

- 2027-2030 General Rate Case - all mileage.
- 2026-2028 Wildfire Mitigation Plan - all mileage beginning in 2027.
- 2028-2037 10-year Electric Underground Plan - all underground mileage beginning in 2028.

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[43] The EPSS and PSPS reliability models calculate consequence using the Interruption Cost Estimate (ICE) model and the customer minutes interrupted (CMI) "value of service" methodology required by the Risk Based Decision Making Framework, resulting in a monetized risk value. PG&E is using the $3.33 per CMI as its weighted average mix between its various customer classes. The ISM understands that this figure is currently being evaluated as part of PG&E's current General Rate Case.

[44] The model incorporates critical customer weighting by applying severity-based multipliers to the CMI and value of service for each customer. These weighted values are then used to proportionally allocate the total dollarized PSPS risk across the system, redistributing overall risk to reflect greater impacts on critical customers.

[45] Note that should PG&E's CMI be modified as part of the current regulatory review, then these bowtie risk figures may change.

[46] Integration of WBCA 2.0 into the Foundry platform limits direct access for the public; the model is accessible only through utility-scheduled walkthroughs, and independent analyses cannot be performed.

RISK TRACKING AND RISK REDUCTION

In prior ISM Reports, the ISM presented observations on numerous PG&E groups, task forces, and programs seeking to track and reduce risk, and to perform root cause evaluations of historical equipment failures and ignitions. In ISM Report 6, the ISM presented its initial observations on the Enhanced Ignition Analysis group and their primary deliverable, the Preliminary Ignition Investigation Reports. The ISM also reported for the first time on the Operational Risk Validation (ORV) group and reviewed their findings and recommended corrective actions from their process evaluations of PG&E's distribution and transmission maintenance programs. The ISM expects to report on additional ORV evaluations in its next ISM Report.

In this section, the ISM presents its observations on the Corrective Actions Program, Material Problem Reports (MPR), PG&E's newly formed Wildfire Strategy Group and Proactive Ignition Mitigation Task Force (the 2025 version of the 2024 R3+ Ignitions Task Force referenced in ISM Report 6).

Corrective Action Program

In ISM Previous Reports, the ISM detailed the establishment and closing out of several individual corrective actions across numerous electrical groups and operations. Many of these corrective actions arose from the identification of process gaps, or as a result of lessons learned from root cause evaluations, with corrective actions ranging from supplemental training, changes to construction standards, requests for extent-of-condition assessments, policy changes, improved data collection, etc. During the current ISM reporting period, the ISM conducted interviews and requested data on the management of the corrective action program itself.

This program is an enterprise-wide process across all PG&E lines of business for identifying, evaluating, tracking, and resolving actual or potential issues, such as failures, nonconformities, unsafe conditions, or improvement opportunities. The Corrective Action Program generated under this program seek opportunities for continuous improvement as a means of reducing risk and improving employee and public safety.

The Corrective Action Program is led by the Director Enterprise CAP and Cause Evaluation, who reports to the Chief Safety Officer. A separate manager is assigned to each line of business' CAPs. For the electric division, one manager is responsible for oversight of all CAPs involving electric operations, vegetation management, and power generation.

CAPs are governed by several policies, procedures and cause evaluation standards which are uniform throughout the company, with the exception of CAPs for PG&E's nuclear operations and assets, which follow separate, federally regulated rules. PG&E notes that program leadership participate in new hire orientations, visit all of PG&E's service centers through the calendar year to refresh information on the CAP process and to discuss what may be in a division's backlog, and to offer assistance where needed.

CAPs can be initiated by any PG&E employee through a CAP mobile app, directly into SAP, or through the SAP web portal. The program team maintains a dashboard, accessible to all employees, and provides a variety of visual management tools to assist in the oversight of the

CAP inventory. The ISM observed many of these customized and automated reports which frequently appear in divisional weekly operating reviews (WOR), and which flag CAPs completed, in-progress, coming due, or overdue.

In addition to individual employees, CAPs are often created by ATS, AFA or the ORV group following any programmatic root cause or internal evaluations or audits. Once a CAP issue has been entered, a CAP review team (made up of a team of SMEs selected by group supervisors) reviews the request and assigns a department owner within two days, who in turn assigns the CAP to an issue owner within the following five days. The issue owner is then responsible for setting the CAP timeline based upon resource availability and CAP resolution needs, evaluating the issue, creating actions, assigning action owners, and closing out the CAP, following the completion of a fix or a 'trend and monitor' recommendation. PG&E states that CAPs are initially assigned a high, medium, low, or Level 5 risk by the CAP review team prior to assignment, and the CAP owner can also assign a high, medium or low prioritization for establishing the important or priority of work in the department.[47]

The total number of CAPs, excluding those from gas operation map corrections, over the past three years has remained steady at approximately 17,000 per year, with Electric Operations and Engineering averaging approximately 4,600 per year.[48] PG&E stated that overdue CAPs were a chronic problem in the past, and that increased diligence and new guidelines caused the number of overdue caps to fall significantly since the start of 2023. During the 2020 to 2023 period, overdue CAPs ranged from 150 to 500 per month. Since 2023, the number of overdue CAPs has generally decreased to under 10 per month. Any CAP extension requires leadership approval, and any CAP overdue by more than 14 days gets elevated to the Vice President level.

Table 6 provides a listing of the types and quantities of electric CAPs over the prior 3.5-year period. As seen from this Table, the largest number of CAPs are compliance in nature and are generated by audit and quality assurance programs.

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[47] Level 5 risk is a designation in PG&E's CAP Risk Matrix Tool that indicate nominal risk. According to PG&E, Level 5 issues are items which may need to be addressed but typically have nominal impact to safety, reliability, compliance, quality, environmental or finance. These include improvement suggestions, business issues, and tracking work activities all not requiring a risk determination. Of the 4,823 Electric CAPs issued in 2024, <1% were designated as High risk, 4% as Medium, 86% as Low, and 9% as Level 5.

[48] Gas operations use CAPs for map correction requests. These average approximately 4,200 per year. The electric department, with few exceptions, does not use CAPs for map corrections, and has an alternative map correction form that field personnel are required to use.

Table 6: Electric CAP Initiation by Type (2022 to June 2025 Totals)

Reliability	699
Map Correction	103
Asset Management	153
Dig-In Third Party	2
Unplanned Outage	270
Dig-In Second Party	40
Maintenance	87
Dig-In PG&E	14
Compliance	**7,613**
Audit and Quality Assurance	6,276
Regulatory Compliance	866
Permit Conditions	291
Process Improvement	145
Enterprise Risk	25
Regulatory Record Correction	11

Program/Process	2,774
Process Improvement Suggestion	1,775
Employee Concern	662
Performance Improvement Suggestion	287
Safety and Health	**2,727**
Employee Safety	1,149
Employee Motor Vehicle Safety	819
Contractor Safety	270
Public Safety	223
Contractor Motor Vehicle Safety	161
Ergonomics	13
Personal Protective Equipment	21
Employee Wellness	57
Industrial Hygiene	14

The ISM randomly identified and followed up on select CAPs during ISM reporting periods to ensure the CAP was closed in the manner that PG&E had specified. In all instances, the materials provided were consistent with the CAP closure requirements.

The ISM observed one instance in its investigations during the prior ISM reporting period, where an incomplete vegetation management CAP was linked to an ignition. The ISM has now received additional information to supplement the incident synopsis provided in ISM Report 6. PG&E reported that a member of the ignitions investigation team initiated the CAP, rather than someone who was a member of the vegetation management (VM) organization. VM interpreted the CAP as an extent of condition review related specifically to the circumstances around that specific incident, and not interpreted as a request for a programmatic review of customer interference procedures. PG&E's EIA team stated that if the CAP had been adequately fulfilled, it is possible that the incident tree from a July 2024 ignition may have been identified for mitigation prior to its failure. PG&E also stated that VM continually reviews and revises its customer interference procedures since that incident, and that its Distribution Interference procedure was revised most recently on March 26, 2025.

In addition to the corrective action program, PG&E requires its employees to fill out Material Problem Reports which are used to report, evaluate, and document defective material, equipment, vehicles, and tools used in its operations. These MPRs are submitted to the Supplier Quality group for review and assignment. PG&E notes that issues relating to equipment safety, supplier advisories, material quality and material design should be addressed by MPRs, while issues relating to the installation or handling of materials and equipment should be addressed through CAPs.

While the ISM did not perform any detailed investigations of individual MPRs or the MPR program, discussions with PG&E construction management indicated that field personnel expressed concerns about the usefulness of MPRs, leading to a reluctance to generate and submit MPRs for recurring issues, given other competing job requirements. Since identifying failure trends is a listed benefit of the MPR program, construction leadership indicated that it encourages field staff to continue to report recurring MPR-related issues.

2024 R3+ Root Cause Evaluation

California experienced a record-setting heatwave in early July 2024. The average temperature in California in July 2024 was the hottest on record, and the 1,000-hour dead fuel moisture reached a 22-year low. During the heatwave from July 1 to July 15, 2024, a spike in ignitions occurred during R3 or higher FPI conditions. In response to these dangerous conditions and the rapid increase in the rate of CPUC reportable ignitions, PG&E initiated the R3+ Ignitions Task Force to identify immediate actions to mitigate the rising ignition trend and to perform a year-end root cause evaluation. The ISM reported on several of the programs initiated and managed by this task force in ISM Report 6.

The task force's end of year evaluation sought potential causal factors behind some of the increased vegetation, equipment and avian caused ignitions during R3+ conditions in 2024. In its evaluations, PG&E concluded that:

- an increase in vegetation-caused ignitions during the heatwave was likely related to heat stress, and most of the trees involved in the ignitions failed due to defects that VM inspections are not likely to identify.
- high ambient temperatures may have led to thermal expansion of its power lines, and contributed to a higher rate of connector and conductor failures in the high heat.[49]
- avian contact was the only driver of R3+ reportable fire ignitions on transmission.
- there was an observed decrease in EPSS effectiveness during the heatwave.
- there was an increase in ignition rate across multiple failure drivers tracked in July 2024. PG&E attributed this to the 22-year low Dead Fuel Moisture in July 2024 and to elevated plant biomass levels after multiple wet winters, which led to a large, receptive fuel bed that could increase the rate and spread of ignitions over PG&E territory.

Table 7 lists the twelve CAPs generated to address each of the five specific causes highlighted above. During the current ISM reporting period, the ISM selected a sample of these CAPS (1, 2, 5, 6 and 12) and discussed the CAP progress and preliminary results with each identified CAP owner. Some of these have been detailed in other sections of this ISM Report 7.

[49] PG&E states in its R3+ evaluation that there is a strong pattern of connector and conductor failure occurring on high heat days (greater than 80°F) and relatively low daily relative humidity (less than 27%). Specifically, 78% of all connector ignitions and 67% of all secondary/service conductor ignitions occurred on days with high heat and relatively low relative humidity.

Table 7: CAPs from the R3+ Cause Evaluation

Cause	Corrective Action
California environmental conditions were more susceptible to ignitions relative to prior years	**Corrective Action 1**: Stand up a Wildfire Strategy Working Group that is nimble enough to monitor and raise to multi-year weather trends such as multi-year wet winters or multi-year drought conditions. **Corrective Action 2**: Evaluate identifying a method to track seasonal fuel quantities and integrate into playbooks for operational mitigations.
Current VM inspections and patrols are not expected to identify all tree failure	**Corrective Action 3**: Evaluate technology to improve identification of tree defects and environmental conditions that lead to failure **Corrective Action 4**: Evaluate effectiveness of vegetation management inspections and tree work.
Current patrol and inspection procedures are not expected to identify all connector and conductor failure modes	**Corrective Action 5**: Improve tracking of connector ignitions by distinguishing between connectors and splices in the Ignition Database. **Corrective Action 6**: Improve tracking of connector failures by tracking connector types for Equipment-caused Connector Failures. **Corrective Action 7**: Evaluate the feasibility of developing an image classification model to identify connectors on the distribution system. **Corrective Action 8**: Audit to assess the knowledge and practices of conductor preparation and connector selection and installation, relative to applicable Standards/Procedures and Work Methods on both Transmission and Distribution systems.
Lack of avian mitigations for transmission structures	**Corrective Action 9**: Evaluate successful installation of pilot for frog covers on Cortina-Mendocino circuit and evaluate potential for implementation of same/similar mitigations on compatible circuits with vendor. **Corrective Action 10**: Evaluate the use of transmission tower attributes (like impaired clearance) and distance to water as inputs to the transmission avian probability model.
EPSS effectiveness decreases at higher delay times and under dryer Dead Fuel Moisture	**Corrective Action 11**: Evaluate EPSS ignition rates under different moisture content conditions using additional lab testing. Consider comparing different delay times as part of testing. **Corrective Action 12**: Review EPSS pilot on selected 3 circuit segments to shift to faster delay time settings. Both ignition rate and reliability impact should be assessed. The sample size may be too small to draw conclusions on the impact to ignition rates.

Wildfire Strategy Working Group

The ISM followed up with PG&E on Corrective Action 1 from Table 7 above, which called for the creation of a new Wildfire Strategy Working Group. The ISM confirmed that the wildfire risk management team created this group, and the ISM received a listing of all the interdisciplinary teams that were brought together for problem solving to identify and prioritize wildfire mitigations.[50] The ISM also reviewed evaluative reports requested by this group (e.g., detailed 2024 review of each EPSS ignition in HFTD, and the analysis of EPSS Hazard Barrier Analysis gaps and opportunities). PG&E subsequently transferred several of the items identified as possible mitigations to a new Proactive Ignition Mitigation Task Force (PIMT) designed to focus on the execution of strategies developed by the Wildfire Strategy Working Group.

[50] Groups attending the Wildfire Strategy Working Group include EPSS, EIA, System Protection, Risk and Data Analytics, Distribution Asset Strategy, Portfolio Management, Meteorology and Fire Science, and Vegetation Management

Proactive Ignition Mitigation Task Force

California again experienced an active wildfire season at the start of 2025. These elevated fire potential conditions were seen in PG&E's weather normalized CPUC reportable fire ignitions, which reached a maximum of 1.55 in June (versus an end-of-year target of 1.16).

Based on the above conditions, PG&E's Incident Command System activated a 2025 PIMT. This task force is similar to the R3+ Task Force which operated in 2024 and was created to unify a series of actions under one umbrella, and address R3+ and other ignitions throughout the remainder of 2025. The stated work of the task force is to oversee implementation of the twelve R3+ root cause evaluation CAPs detailed in the prior section, analyse and implement actions based on 2025 year-to-date events, improve wildfire mitigation group coordination and tools to better position the operations for higher risk periods, and to undertake actions from learnings from the 2025 Southern California fires.

The task force, led by the VP - Wildfire Mitigation, is comprised of 22 PG&E individuals, and includes the section chiefs for operations, planning, logistics, intelligence, and finance. The task force conducts daily check-in meetings, along with weekly operations and planning meetings to assist in the management and oversight of 19 separate workstreams in various stages of evaluation, scoping, staging, and execution as of the end of July.

The ISM previously detailed some of the PIMT workstreams in earlier sections of this ISM Report, such as the WiRE project (Outages and Reliability Trends and Observations), targeted zero delay EPSS (Fast Trip Program Updates), deployment of continuous monitoring technology (Continuous Monitoring Program Updates), EPSS patrol review (PIIR Reviews), and service installation standards and quality control for new service installs (PIIR Reviews).

During the current ISM reporting period, the ISM also performed deeper investigations into three other PIMT workstreams: the distribution long span pilot, service breakaway disconnects, and actions taken from the Southern California fires. The ISM has not yet observed any information on the following in-process PIMT workstreams: wildfire response structural process and tools,[51] distribution pole clearing, transmission poles in high winds, transmission wire slap risk, vegetation ignition analysis and insights, and EPSS zero trip delay.[52]

Distribution Long Spans Pilot and Transmission Long Span Deficiencies

PG&E initiated a detailed review of long spans as a source of elevated risk on its distribution system following a May 2025 ignition on an EPSS enabled line which led to a 0.25 to 10 acre grass fire. The incident span was approximately 800 feet long and showed a history of wire

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[51] This workstream seeks to automate several reports used in PSPS and wildfire planning events, such as Operations Summary Report, the Dual Event Outages Report and the Incident Action Plan, in order to ensure that PG&E's focus is on execution during PSPS and wildfire response, instead of manually compiling data from multiple sources.

[52] The majority of the EPSS system is on 0-30 millisecond (ms) delay, but more ignitions occur with 60 ms delay times. Specifically, 20% of circuit mile minutes are on >60ms settings but result in 40% of R3+ ignitions. The task force is examining which circuits should deploy zero-delay, what thresholds to use for turning zero delay on and off, and the projected reliability and customer impacts of any changes

slap. PG&E's meteorolgical team confirmed that a wind advisory was in effect at the time of the incident which could have been a contributing factor for the line to line contact. Following the incident, spreader brackets were installed between the conductors to maintain separation and prevent future contact. A Safety Condition Assessment Review (SCAR) of the incident location and adjacent spans identified several other E and F tag conditions that could pose a continued risk if not remediated.

Following this incident, PG&E conducted an analysis into ignitions involving long distribution spans. PG&E reported that while primary distribution spans over 600 feet in length constitued less than 2% of total spans in HFRA, these spans have been involved in approximately 9% of ignition incidents since 2021.[53] Various drivers were identied as contributing to the long span ignitions, including vegetation, wire slap, conductor fatigue, and loose hardware. PG&E also identified that ignitions involving long spans are more than twice as likely to result in a fire over 0.25 acres compared to spans under 600 feet. In reviewing long span risk by wildfire consequence, PG&E noted that there is a concentration of risk among a smaller number of long spans, with 216 long spans (1.9%) making up 20% of the consequence risk, and with 957 long spans (8.3%) making up 50% of the consequence risk.

As a result of its findings, PG&E identified an area with a concentration of 107 long spans in a high wildfire consequence area in which to undertake a long span risk reduction pilot. The pilot includes performing aerial scans with specific shot lists and data collection sheets, and, where required, to create and execute short-cycle corrective work.[54]

As part of its long spans workstream, PG&E seeks to plan and fund similar long span inspections on the remaining 850 long spans in the top 50% of wildfire consequence risk before the start of the 2026 fire season. PG&E stated that it will also review and update standards relative to HFRA long-spans based on any lessons learned from the pilot.

In addition to distribution long spans, the ISM also received a PIIR in April 2025 for an August 2024 transmission ignition. The PIIR noted that the ignition was likely due to high cycle fatigue, and that vibration dampers were not installed on this 374-foot span. The PIIR further noted that PG&E's standard requires dampers to be installed on transmission lines spanning over two hundred feet in length. After vibration dampers were installed on that span, plus an adjacent span, PG&E later performed a SCAR in January 2025, with a drone flight five spans to the north and four spans to the south of the incident location, finding additional missing dampers. The PIIR noted that a priority E tag was created to have vibration dampers installed on all the adjacent spans of similar length so that they would be protected from fatigue damage due to wind vibrations.[55] The schedule due date for that work is listed as November 2027.

The ISM then received a PIIR the following month for another transmission long span ignition involving a failed 106-year-old conductor showing signs of fatigue, also not built to current

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[53] Of approximately 713,000 spans in HFTD or HFRA, approximately 11,500 are 600 feet or greater in length. Of 359 ignitions assessed in HFTD/HFRA since 2021, 32 involved spans 600 feet or greater.

[54] PG&E indicated that specific recommendations will follow after an analysis of the inspection findings from these 107 long spans.

[55] Ignition 20241195N

PG&E standards, with missing vibration dampers. In addition to these two transmission ignitions, PG&E confirmed that since 2020, only one other transmission ignition occurred in 2022 relating to conductor failure or wire to wire contact, where dampers should have been installed based on its current revision of the vibration damper standard.

Following the receipt of the long span pilot information and the two PIIRs involving the missing transmission line vibration dampers, the ISM learned that PG&E inspectors are not currently tasked with looking to see if vibration dampers are missing on span lengths that would require them. PG&E stated that if the dampers exist on a line, they are required to be inspected to ensure they are not in need of maintenance or replacement.

Service Breakaway Connectors

A service drop is the line from the distribution pole to a customer's home or business. If falling vegetation strikes a service drop that does not have a breakaway connector, the line can sever from the building and remain energized. Service breakaway connectors are designed so that upon impact from vegetation or other force pulls on the service drop, the connector will separate cleanly rather than tearing down wires or breaking poles, reducing the chances of an energized line falling to the ground and creating sparks that could ignite dry vegetation. [56] Breakaway connectors can also lead to faster restoration of faults as they may be easier to repair.

From 2018 to 2024 there were 236 ignitions on service drops, with 64 of these occurring in HFTD. As part of its extent of condition review on service drop ignitions, PG&E determined that 14% of its total ignitions, and 19% of its R3+ ignitions in HFTD over the past two years were tied to service drops, with the majority of these having been caused by vegetation contact.

While revised standards now require the installation of breakaway connectors in new construction, PG&E identified a population of approximately 8,300 higher risk services drops in HFTD where it would like to replace the original connectors with breakaways. PG&E informed the ISM that it intends to exceed its WMP commitment to install 3,000 of these breakaway connectors over the 2026 to 2028 period, and that the PIMT is currently in the process of prioritizing its work plans. In addition, the PIMT also identified and recently secured supplemental funding for a 2025 pilot to install connector replacements at 200 locations out of a population of 594 which experienced two or more vegetation fall-in events.

In addition to prioritizing and managing the breakaway connector replacement program, the PIMT indicated it will also confirm, via field audits, that the standard changes relating to breakaway connector installations are being followed, and review the change management that was executed when the standard was modified in June 2024 and July 2025 for newly installed service drops to include service breakaway connectors.

Actions Taken from Southern California Fires

Following the Eaton fire in Southern California in 2025, PG&E and other utilities started to

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[56] PG&E stated its lab tested service breakaways and found that when operating as designed, the associated service conductor deenergizes and "fails safe", preventing ignition after a vegetation fall-in event. PG&E further stated as this is a new product, it does not have historical data to validate effectiveness projections.

perform substantial reviews of transmission failure modes relative to induction and structure grounding.

The PIMT is performing these reviews under three workstreams:

- Transmission structure grounding: Identify the number of structures that require grounding, ensure that all are grounded, and confirm that the standard is updated.[57]
- Transmission line removals: 1) Validate the removal of all transmission idle lines by August 2025, and 2) confirm via documentation the date of removal of each of the idle lines that was in the asset records on January 1, 2025.
- Temporary Idle Transmission Lines Mitigation: Ensure that temporary idle lines are grounded or sectionalized, and develop tracker of lines to show whether grounded or sectionalized.

The ISM received preliminary information on these in-progress reviews, and expects to report on them in greater detail in its next ISM Report. PG&E reported that it is being assisted in its evaluations by an external company that was instrumental in assisting PG&E in the initial development of its transmission OA model, and that nine circuits were classified as having elevated induction risk.

In addition to these three idle line and induction risk workstreams, PG&E is also undertaking the following related activities:

- re-evaluating PSPS thresholds and processes to account for changes to the OA model, revised grounding procedures, and enhanced calculations for induction risk during PSPS events.
- proactively removing fuel from the base of approximately 6,500 transmission support structures in high consequence risk locations as a method to prevent ignition. This follows PG&E analysis which indicates that approximately 80% of PG&E's historic ignitions associated with the transmission system occur at the base of support structures.
- evaluating whether high resolution satellite imagery can quantify the change in ground fuels before and after the clearing described above.

In addition to these mitigations, PG&E is also evaluating methodologies to quantify the risk of urban conflagration within its service territory. An urban conflagration is a large-scale, destructive fire that spreads rapidly through a densely populated urban area, causing widespread damage and potentially significant loss of life. PG&E is working with two wildfire-spread modeling companies to further refine its structures at risk, and its structure-to-structure fire spread model. PG&E informed the ISM that its new urban conflagration model

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[57] PG&E utilizes a newly developed Induction Driven Ignition model to inform if de-energized lines should be grounded or not during a PSPS event. The model has three components to 1) model the failure paths for probability of wire down through the OA model, 2) determine the induced currents and voltages in de-energized line from energized line based on historic loading and geospatial data, and 3) determine the probability of ignition given wire down for grounded or ungrounded conditions based on fuel and soil moisture, current weather and the Induction model. The ISM will continue to monitor any new developments of the Induction Driven Ignition Model.

prototype has been built and is undergoing validation. PG&E anticipates that the PSPS group will be most impacted by the introduction of urban conflagration into the risk models, which may result in the adjustment of certain PSPS guidance thresholds.

INTEGRATED GRID PLAN

PG&E continued to advance the development and initial usage of its Integrated Grid Plan (IGP) during the current ISM reporting period. In prior ISM Reports, the ISM introduced IGP as a multi-phase, circuit-based program designed to optimize PG&E's investments over a 10-year planning horizon. While this report section focuses on PG&E's IGP for its electrical system (covering distribution, transmission, and substations), it should be noted that PG&E is also in various stages of development for IGP investment planning for its information technology (IT), gas and power generation operations.

PG&E's stated goals for its electric IGP are to design and implement stable, transparent actionable, and economically optimized long-term strategic plans for its systems, focusing on areas of wildfire risk reduction, capacity expansion, asset health, system reliability, customer equity, and climate resilience. IGP also focuses on reducing customer outages and costs through its multi-year understanding of system needs, and its bundled approaches to work execution. This work bundling is designed to benefit from competitive contractor bulk-pricing of projects, improved resource management, and longer-term permit planning.

The ISM observed a significant shift in IGP's primary construction over the past three years, with early versions of IGP using a top-down approach, where PG&E set investment program priorities and then had the IGP platform determine the optimal spending within those established priorities. Initial IGP output observed by the ISM using this approach prioritized wildfire reduction expenditures in the initial years, shifting expenditures more towards greater capacity expansion and reliability improvements in the later years of the original 10-year planning horizon.

The current releases of IGP are now based on a bottoms-up approach, where system knowledge is input into the model, with the investment decisions now being driven by asset/component needs that get aggregated up. To accomplish this bottom-up approach, PG&E first consolidated asset data from more than sixty sets into a Foundry-based System Needs Analysis Platform (SNAP). This includes information on asset attributes and location, asset health, capacity loading, and risk. Asset risk is introduced into IGP via five current models covering the areas of capacity, reliability, wildfire, public safety and finance.

PG&E utilizes a customizable, off-the-shelf, third-party software solution to turn its system needs assessments into optimized, bundled, executable, and prioritized workplans.[58]

The current 3.2 release of IGP includes a scope of work which spans thirty-one capital Maintenance Activity Type (MAT) codes. These MAT codes represent various distribution,

[58] In its benchmarking, PG&E noted that that numerous U.S. utilities are moving in the direction of IGP, and that the other major California utilities are on a similar path and are in various stages of using the same third-party software for their own investment planning.

transmission, and substation work types, including organic load growth, reliability improvements, wildfire mitigation, and asset health initiatives. PG&E stated that release 3.2 will be able to propose circuit-based work across up to 31 MAT codes. In other words, each bundled investment will address various circuit needs. PG&E's longer term IGP roadmap includes additional model enhancements out to 2027 designed to further increase the amount of electrical capital and expense that can be optimized, and to improve integration of IGP's output with its business operations.

Although IGP did not inform investment planning in PG&E's current General Rate Case, it did see its first use in 2024 with the planning of last year's first mega-bundling of approximately $100 million of maintenance tag work.[59] As detailed later in this ISM Report, based on the successful reduction in unit costs and the improved customer reliability of the 2024 mega-bundling program, PG&E again used IGP for the planning of an expanded maintenance tag mega-bundling program in 2025, with PG&E noting that it is continuing to see comparable savings to that experienced in 2024.

Going forward, PG&E expects IGP to begin to value and optimize investments for approximately 65% of the electric plannable capital portfolio in 2026. This would equate to approximately $5 billion of expenditure starting in 2027, excluding non-plannable work.[60]

Based upon IGP's optimization and bundling potential, PG&E projects that the expansion of IGP across all its functional areas may save up to $3.7 billion from 2026 through 2030, with approximately $3 billion of those savings projected to come from the electric division.[61]

In discussions with IGP leadership, the ISM questioned how IGP was set up to address asset age in the planning process. In ISM Previous Reports, the ISM observed that several classes of electrical assets, such as poles, conductors and transformers, were not currently being replaced at rates needed over a longer term, when factoring in the age profile of the assets and their expected useful life.

PG&E stated that to aid in its asset replacement decision making within IGP, it relies on asset risk data that is sourced from several of its risk models aggregated in SNAP, where asset age (as detailed in ISM Report 6) is a high-ranking influencer of risk value in the machine learning models. In addition to asset age, these models also consider factors such as material type, environmental exposure, and historical performance, to provide a more comprehensive view of asset condition and risk. Asset age, therefore, is currently factored in at the individual asset level as opposed to having general guardrail asset age levels imposed as constraints on the modeling.

When questioned by the ISM as to where top-down constraints are currently imposed on IGP, PG&E noted that aggregate annual expenditure levels are applied to the portfolio selection

[59] ISM Report 6, pg. 50.

[60] PG&E's non-plannable electric system work represents approximately 45% of its annual electric capital expenditures, and includes emergency, new business, and other emergent or prescriptive work.

[61] This approximately $3 billion in projected electric operations savings equates to a 10% savings on the 55% portion of the 2026-2030 ~$55 billion projected electrical operations expenditures that IGP will address.

process. PG&E also noted that its IGP and Reliability groups are working together to apply 2026 and 2027 SAIDI improvement targets as a constraint, with the optimization engine selecting investments that help achieve this objective, while simultaneously seeking ways in which these targeted investments can be bundled within the programs being guided by IGP.

ASSET AGE AND USEFUL LIFE

The ISM began reporting on the asset age and useful life of select PG&E equipment in ISM Reports 1 (substation assets and underground transmission equipment) and 2 (distribution poles and conductors). In ISM Report 6, the ISM provided its observations on PG&E's ongoing efforts to determine the age of its in-service equipment, provided information on the age, replacement rates and replacement strategy for its non-substation distribution overhead transformers, and updated and expanded upon the ISM's prior data on age and replacement rates for PG&E's poles and conductors.

Asset age commonly refers to how long an asset/piece of equipment remains in operational service, while useful life commonly refers to the estimated length of time equipment can be expected to effectively contribute to operations. Asset age is often one of many factors considered when determining when an asset is targeted for replacement. Other factors may include utilization (e.g., number of times equipment operates), performance (e.g., no, or minimal degradation if operating as expected), asset wear (e.g., amount of corrosion), etc.

In the current ISM reporting period, the ISM observed a potential emerging situation relating to protective devices, with PG&E noting "system protection relays are at risk for increased failure rates because investment in replacements do not match end of life cycle forecasts."

Protective equipment includes devices to safely isolate the electric system during equipment failures to prevent cascading outages, to limit customer outages, and to limit further damage of equipment. PG&E uses these automated protection systems to prevent bulk electric system stability issues and to take corrective actions (e.g., shedding load or reconfiguring the systems) to maintain grid stability. If the relays fail to operate when needed, there can be material impacts on public and employee safety, equipment, and increased wildfire risk. While all substation equipment has a probability of failure and a consequence of failure, these protection systems have an inherent higher criticality because of their function.

Table 8: PG&E Protective Relays

Relay Type	Number in Service	Est. Useful Life	Number Currently Past Useful Life	Proj. Number Past Useful Life (2030)
Microprocessor	23,431	20 years	2,845	6,437
Solid State	1,011	20 years	681	776
Electro-Mechanical	5,397	40 years	3,218	3,723
Total	**29,821**		**6,744**	**10,936**
Percentage			23%	37%

As seen in Table 8, PG&E has approximately 30,000 protective relays in service at 950 substations of three types: microprocessor (79%), solid-state (3%) and electro-mechanical (18%).

PG&E stated that the useful life of the microprocessor and solid-state relays are 20 years, and the useful life for the electro-mechanical relays are 40 years. PG&E also notes that while the vendors of the microprocessor types recommend replacement every 15 years, PG&E's internal sustainability analysis based on simulations and historical data analysis indicates a life span of 20 years. Figure 10 shows the large increase in PG&E's projected probability of failure for the microprocessor and solid-state relays starting in year 20, while the more complex electro-mechanical relays (which do not have the same finite read/write cycle limitations or target power supply life of the microprocessors) have increasing failure rates spread over a longer period of time.

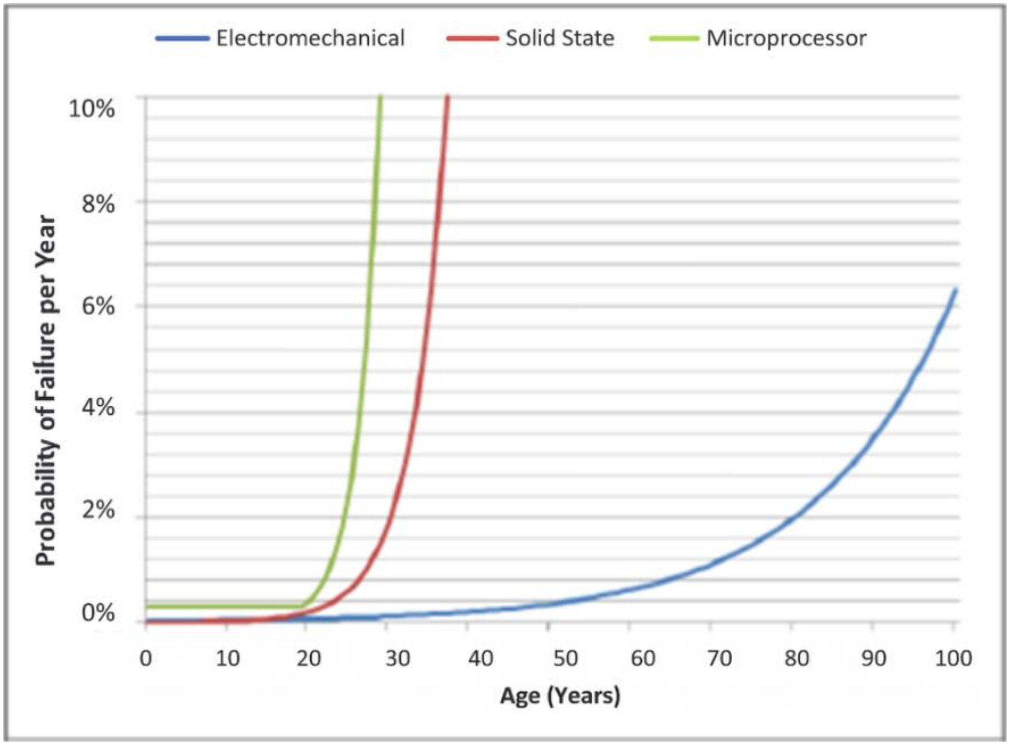

Figure 10: Relay Failure Rates by Age and Type[62]

Table 8 shows that at present, approximately 23% of the relays are past their useful life, and with no planned replacements, PG&E projects that 36% of the relays would be at the end of life by 2030.

With the increasing number of relays past their useful life, PG&E is also seeing an increase in the number of relay failures. While 78 relays failed in 2016, this number increased by approximately 140% to 188 failures in 2024, with approximately 90% of these being microprocessor relays.[63]

Figure 11 shows the distribution of in-service relays by age and type. Based on this distribution, PG&E projects that in the next five years, an additional $1.5 billion worth of relays will come to the end of their useful life (represented by the green box in Figure 11), and that to

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[62] The ISM has not independently validated the simulation that was used to create this figure.

[63] Note that the number of failures per year have not been normalized by the number of relays in operation.

cover the remaining backlog of relays past their useful life would require an additional $1.3 billion (represented by the overdue relays in the red box in Figure 11).

Historical funding for the replacement of relays declined in recent years. From 2017 through 2022, funding for relay replacements averaged approximately $60 million per year. This funding declined to approximately $40 million in 2023 and 2024, and was set to decline further to $31 million in 2025, before PG&E recently allocated an additional $8 million to bring funding back up to the previous year's levels.

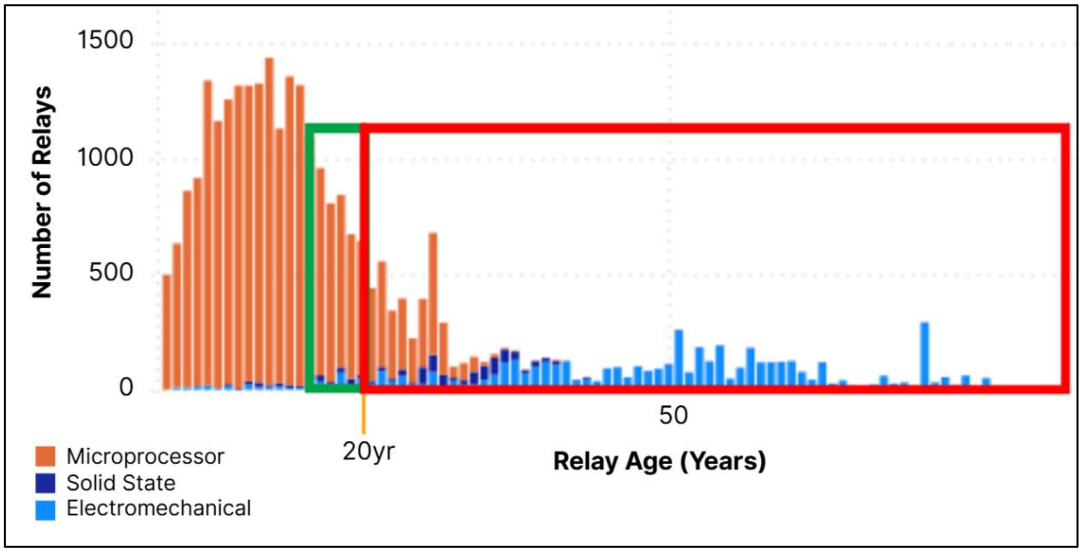


Figure 11: Population of Relays by Age and Type

With funding below the level needed to proactively replace relays at the end of the useful life, PG&E shifted to a "just-in-time" prioritization of relays, focusing on those deemed to have the highest predicted probability of failure (PoF) and the highest consequence of failure (CoF).[64] Based upon its analysis, PG&E's system protection group estimated that to replace its Priority 1 relays (66 relays with the highest PoF and the highest CoF) would require $200 million.[65] This exceeds the $60 million which the systems protection group indicated it recently secured for its 2026 funding. When questioned by the ISM how these funds would then be allocated, the group indicated that it would start with the highest risk relays within the Priority 1 population.

PG&E stated that "the lack of funding to replace these assets are expected to increase the number of customers that will be impacted by an outage and decrease the reliability of our system." While PG&E's system includes built-in redundancy, various other controls and

[64] The PoF is based upon a health score that combines asset age with failure rate, manufacturer/model, outage and maintenance history, system configuration, environmental issues, and safety impact. The COF is based upon wildfire risk (wildfire spread, defensible space around substations), public safety risk, emergency response, and reliability (criticality, system and customer impact, and cascading outages.

[65] PG&E stated that the cost of individual replacements can range from $1.1 million for a full panel replacement to $0.2 million for one-for-one relay replacements.

mitigations, and inventory for commonly failed relays is available for easy replacement, PG&E is still projecting increased numbers of age-related relay transmission outage failures from approximately three in 2025 to approximately five by 2030 (assuming no future relay replacements).

When questioned by the ISM on how protective relays were being treated in IGP investment prioritization and planning, the IGP group informed the ISM that system protection relays are not currently included in the IGP program, but that as the IGP program continues to evolve, these assets are expected to be incorporated, and that once included IGP will be able to help address these funding and increasing risk concerns.

ASSET INSPECTION QUALITY CONTROL & ASSURANCE

PG&E's Electric Asset Inspection Program establishes the framework for routine and enhanced inspections of poles, towers, conductors, and associated distribution and transmission equipment across its service territory. These inspections are performed to comply with state regulations and requirements such as GO 165[66], which sets inspection cycles and record-keeping requirements for electric distribution assets. PG&E's program incorporates both scheduled patrols and detailed inspections, using ground, aerial, climbing, infrared, and other methods depending on asset type and location. The ISM has reported on PG&E's inspection programs in Previous Reports, including the transition from predominantly ground-based in 2023 to aerial-based in 2024

During the current ISM reporting period the ISM observed PG&E's Quality Control (QC) and Quality Assurance (QA) process. PG&E maintains separate QC and QA groups to review inspection activities performed by the System Inspections (SI) team. QC provides broad oversight of inspection quality across the system, performing QC review of approximately 80% of the total. QA performs fewer overall inspections, but their inspections assess both the original inspection and the QC review.

WMP Commitments and Targets

PG&E's 2023–2025 WMP established targets for System Inspections. In 2025, these targets include a total of 244,000 distribution inspections and 48,788 transmission inspections (ground, aerial, climbing, and infrared). Within these commitments, the QC group has 2025 targets for:

- Distribution: 170,000 inspections
- Transmission: 17,450 inspections

The QA group has 2025 targets for:

- Distribution: 1,500 inspections
- Transmission: 500 inspections

[66] Adopted in 1996, General Order 165 establishes inspection and record-keeping requirements for electric distribution facilities, including minimum inspection cycles for overhead and underground assets.

PG&E reports that it is on track, as of 7/31/2025, to achieve its annual WMP QC and QA commitment targets for distribution and transmission.

QC Inspections and Performance

PG&E stated that QC inspections are conducted primarily by contractor personnel, with approximately 40 desktop reviews completed by an inspector per day. QC is staffed by approximately 35 contractors, nine SMEs, and 5–6 support staff. Annual training (1–2 weeks) is provided to update inspectors on inspection protocols and job aid modifications.

PG&E's QC's review process involves completing an independent inspection checklist, and if any findings are noted, the inspector posts them in a Microsoft Teams chat for SME review. For A- or X-priority tags, a supervisor is notified directly.

If a QC inspector identifies a B-tag or any lower priority EC-tag, or recommends a tag priority change, the inspection is referred to PG&E's Centralized Inspection Review Team or Package Consensus Review Team for further assessment. If photos or inspection records are incomplete, QC inspectors can request a reinspection.

The WMP includes System Inspection pass rate targets of 95% and 95% for distribution and transmission, respectively, which PG&E reported is at 99.99% and 99.90% through 7/31/2025. PG&E indicated that pass rate targets only apply to critical tags (A-, X-, & B-Tags).

Table 9 provides a breakdown of QC's distribution inspection discrepancies through 7/31/2025. PG&E reported that it experienced two transmission related discrepancies that were both related to conductor issues.

Table 9: QC Findings by Frequency and Type

Distribution Findings Through 7/31/2025	Count	% of Total
Service conductor exposed; broken/damaged…	26	34.2%
Primary/service conductor broken/damaged; bird caged…	15	19.7%
Broken/cracked primary/service bushing; leak/seep…	11	14.5%
Loose or missing hardware…	9	11.8%
Cotter key loose/missing…	5	6.6%
Damaged pole; crossarm; insulators…	5	6.6%
Tie wire broken; corroded; loose…	5	6.6%

QA Inspections and Performance

QA performs a smaller sample review compared to QC, using both desktop and field inspection methods. QA inspections are primarily ground-based but may include aerial reviews, and they are conducted in accordance with GO 165 standards. Currently all of the QA inspectors are contractors and all of them are Qualified Electrical Workers (QEWs).

QA conducts approximately 2,000 inspections annually, serving as a backstop to both the original inspection and QC's review. If QA identifies conditions that warrant new tags, those tags must be reviewed by a QA SME before being entered into SAP. They are also referred to CIRT for review by an Inspection Review Specialist (IRS). Through 7/31/2025, QA found two distribution related inspection discrepancies: "failed to observe an idle facility," and a pole broken or damaged.

QA Field Inspection Observations

The ISM shadowed a QA inspector performing inspections on two distribution assets. The inspector used a Survey123 checklist, supported by PG&E's distribution inspection job aid and identified as GO 165 compliant, to record conditions and note discrepancies. Approximately 10–12 photographs were taken with an iPad for asset verification. The inspector noted that a higher resolution camera (a Nikon 950 camera) would be used for close-up images of potential issues.

PG&E explained that potential discrepancies are documented as new tags by photographing the condition with the Nikon, uploading the image to the iPad, and attaching it to the Survey123 checklist in the field. Tags are not finalized until reviewed by a supervisor or SME lead. The inspector did not identify any discrepancies during the time of the ISM's site visit.

DISTRIBUTION MAINTENANCE, EC-TAGS, AND BACKLOG

PG&E's 2023–2025 WMP established programs to address the backlog of Electric Corrective (EC) Tags in HFTD. The WMP set a goal of eliminating the HFTD maintenance tag backlog by 2029 by prioritizing maintenance work through a risk-spend efficiency approach and bundling repairs within isolation zones to reduce outages and improve efficiency.

PG&E has established several programs and groups to help address the EC tag backlog, including the establishment of an Incident Management Team (IMT) to drive the resolution of past-due B tags. The following provides an overview of the ISM's review of B tag field observations, EC tag and cleanup programs, an update on PG&E's 2025 Mega Bundle program, and field observations of routine tag maintenance.

Open and Past Due B Tags Field Review

In July 2024, PG&E had over 10,000 open B tags in HFTD with almost 40% of them being past their due date. In meetings in early 2025, PG&E stated that B tags are effective in identifying compelling asset conditions and suggested that failure rates would likely be higher if B tags were allowed to become overdue. In 2025, PG&E established a B tag IMT to drive processes to resolve open B tags in HFTD by the end of July 2025. PG&E reported that it resolved nearly 3,000 past-due B tags, and the remaining 196 past due tags (as of 7/31/2025) had certain dependencies that needed to be closed before the tag could be repaired.[67] As of the end of August, PG&E reported that it resolved all past due B tags.

Given that B tags generally carry a six-month time requirement, and PG&E had a substantial backlog of overdue B tags (until recently), the ISM conducted field reviews to assess current field conditions and validate the timeliness and accuracy of B tag notifications. According to PG&E, 600 overhead failure A tags were generated on structures with an open B tag at the time of the A tag between 2022 and September 2025. Additionally, during that same time period,

[67] 10 Estimating, 73 Scheduled, 18 Pending Closure, 95 Exemption Process.

over 2,000 overhead non-failure A tags were generated on structures with an open B tag.[68] The ISM continues to review past due tags.

PG&E regularly provides the ISM with updates on completed, canceled, and open EC tags across its service territory. As part of this review, the ISM initiated ground field inspections of open B tags to assess current status and determine whether conditions may warrant a second review. These inspections focus on verifying whether work was completed, identifying tags that may be past their required notification dates, and evaluating whether field conditions align with PG&E's tagging criteria.

Table 10: ISM Field Review Findings

Total B Tags Reviewed	Complete vs Open Upon Arrival	Past Due vs Within Expected Timeframe Upon Arrival	Status as of July 31, 2025
102 Total B Tags Reviewed	40 Work Complete		
	62 Notification Open	31 Past Due	10 Open
			21 Complete
		31 Within Expected Timeframe	7 Open
			24 Complete

As of June 2025, the ISM began reviewing a dataset containing approximately 7,000 open B tags. Through July 31, 2025, the ISM performed a field review of 102 tags as summarized in Table 10. During the course of the ISM's review, three open B tags were referred to PG&E for additional review - two past due and one current. These open B tags are shown in the photos below. PG&E has since completed the repair of all three B tags.

Figure 12: Representative B-Tag Field Observations (Conductor Strain on Insulators (left); Cracked Pole Below Voltage Regulator (middle); Crossarm Damage at Insulator (right))

Tag Clean-Up Programs and Tag Cancellations

In prior reports, the ISM presented observations related to PG&E's tag clean-up and cancellation programs. In ISM Report 4, the ISM noted that PG&E created the Comprehensive

[68] PG&E defines overhead failure A tags as those caused by equipment failure, pole rot, unknown, or other. A tags identified during an inspection (or within three days of an inspection) and those caused by vegetation, third-party contact, or other non-equipment issues were excluded as non-failures. Non-failure A tags include inspection findings, proactive work, or other causes not directly linked to equipment failure.

Pole Inspection (CPI) program[69] to address a growing number of outstanding pole repair and replacement notifications. In ISM Report 5, the ISM observed that CPI expanded to include all equipment with open maintenance tags, with any proposed EC-tag modifications being reviewed by the CIRT.

As of July 31, 2025, year-to-date CPI inspection volumes exceeded EOY targets across aerial and PTT, with CPI CIRT, PACT (described below), and Job Owner Reviews exceeding YTD targets. Year-to-date, PG&E completed over 20,000 aerial inspections and roughly 2,000 PTT inspections for CPI.

During the current ISM reporting period, PG&E created the Package Consensus Review Team (PACT) to assist with EC-tag reviews. According to PG&E, three programs now contribute to tag re-evaluation and prioritization: (1) CIRT, (2) PACT, and (3) pending EC validations (updates to PG&E's standards).

PACT is comprised of QEWs that perform desktop reviews. These reviews address work readiness (e.g., tag bundling), asset strategy (guidance revisions), and steady-state inspections. PACT is tasked with prioritizing EC-tag modifications for the current and the following year, reassessing open EC-tags against current standards, and reviewing Mega Bundle tags. PG&E stated that PACT reviews are often triggered by recent field inspections, providing desktop reviewers with updated imagery and inspection results.

PG&E reported that PACT reviews resulted in over 24,000 EC-tag cancellations located within HFTD resulting in approximately $176 million in avoided costs year-to-date. While pole-related cancellations (through the CPI process) accounted for the majority of recent activity, non-pole assets comprised 75% of total cancellations for the year.

PG&E provided the ISM with a comprehensive listing of all cancelled tags for 2025 that are inclusive of CPI (CIRT), PACT, and other reviews. Table 11 summarizes PG&E's cancelled tags and identifies the total tags by "cancel reason," tag priority, and HFTD designation. Through 7/31/2025, PG&E cancelled a total of 41,373 tags.

Table 11: Total Tag Cancellations, by Cancel Reason, Through 7/31/2025

2025 Through 7/31/2025		% of	By Tag Priority							By Fire Threat				
Cancel Reason	Total	Total	A	B	X	E	F	H	-	TIER 3	TIER 2	Zone 1	Buffer Zone	Non-HFTD
No Compelling/Regulator Condition Exist	24,347	58.8%	73	196	45	14,201	9,344	488	-	5,325	15,021	99	-	3,902
Duplicate EC for Same Location	5,821	14.1%	292	478	82	3,977	898	93	1	904	2,061	18	-	2,838
All Found Completed/Resolved on Arrival	4,281	10.3%	94	268	15	1,997	1,767	140	-	722	1,415	8	-	2,136
Completed under another Program	2,070	5.0%	69	372	28	1,133	258	209	1	323	1,006	4	-	737
Created in Error (Desk Cancelation)	1,582	3.8%	1,317	53	117	64	28	1	2	787	155	3	8	629
Converted to another Notif-Type	772	1.9%	121	40	72	207	326	6	-	58	178	1	-	535
"Dummy" for order only	454	1.1%	437	-	-	9	8	-	-	32	8	1	-	413
-	2,046	4.9%	654	901	4	426	58	-	3	122	262	4	-	1,658
Total	41,373	100.0%	3,057	2,308	363	22,014	12,687	937	7	8,273	20,106	138	8	12,848

The following provides a brief explanation of PG&E's Cancel Reason Designation:

- No Compelling/Regulator Condition Exist: Issue does not require corrective action under PG&E or regulatory standards.
- Duplicate EC for Same Location: A duplicate tag exists; original remains active.

[69] CPI re-inspections use Pole Test and Treat and aerial methods.

- All Found Completed/Resolved on Arrival: Crews determined the issue was already corrected.
- Completed under another Program: Work addressed under a different PG&E program.
- Created in Error (Desk Cancelation): Administrative or clerical error; tag canceled without field action.
- Converted to another Notification-Type: Work continues under other notification categories (e.g., capital rebuild, vegetation, or emergency construction) and the tag was cancelled to prevent duplicate tracking,
- 'Dummy' for order only: Created solely to generate an order; no work required.
- Blank: Missing SAP field; PG&E reports a CAP is underway to address documentation gaps.

PG&E expanded its tag cleanup initiatives and established specialized teams such as CIRT and PACT to address the EC tag backlog. The ISM will continue to monitor the implementation of these programs and report on material observations.

Mega Bundle Program Update

PG&E initiated a maintenance tag consolidation pilot program in 2024 called "Mega Bundling," where all maintenance work and associated tags for a complete circuit, including lower priority "E" and "F" tags, were consolidated into a single, large project. The stated goal of the Mega Bundle program is to reduce tag backlog, improve customer reliability by minimizing repair outages, and improve cost efficiency by dedicating resources and improving logistics. Mega Bundles are treated as large projects, where requests for proposals are issued, bids are evaluated, and the project is fully scheduled, permitted, and procured.

The 2025 Mega Bundling program differs from the 2024 program in that the revised program considers proximity or "concentration" of tags to improve efficiency. Another change is that the scope of a project may be limited to a circuit protection zone (CPZ) rather than an entire circuit to reduce impacts and outages to customers. Circuits are screened based on Risk Spend Efficiency, where projects with high RSE's become candidates for the Mega Bundling Program. Once selected, the project undergoes the 10-step process to assess and validate the workplan, coordinate cross-functionally within PG&E divisions and groups, finalize (freeze) the scope, complete vendor negotiations and contracts, and execute the work.

Mega Bundles are inspected by System Inspection by the end of a year, and again by the end of March - before the work begins. EC tags with short due dates, like "B tags," may reside in a Mega Bundle Project if they can be completed on time. However, PG&E stated that a team monitors B tags, and if the work will not be completed timely, a crew is dispatched to complete the tag within the designated due date, outside of the Mega Bundle project.

The Mega Bundle program is designed to enable cross-functional coordination to close out existing EC tags. Other than scheduling inspections to precede the scoping of a project, the program does not reprioritize routine work. For instance, while Vegetation Management participates in the planning of Mega Bundle Projects, it is only from the perspective of closing out open VM related tags. Vegetation Management's routine and second patrols are not scheduled to occur prior to a Mega Bundle project.

The following provides an overview of the 2024 program results, updated targets for the 2025 program, and the ISM's field observations.

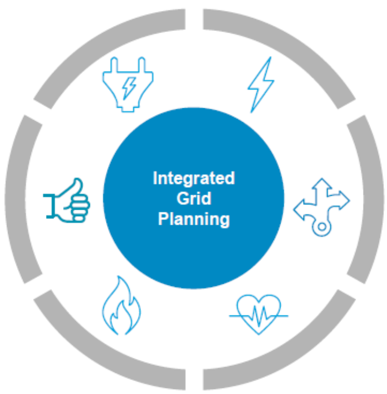
Mega Bundle Program Results and Targets

The 2025 Mega Bundle program has grown in scale based on PG&E's reported success of the 2024 pilot program. The 2024 pilot program closed approximately 8,200 tags, representing approximately $100 million worth of work and 10% of the total closed tags. As depicted in the following figure, PG&E reports that the program met key objectives, including reducing customer impacts, enhancing safety, and optimizing costs. PG&E stated over 35 average customer outage minutes were saved with a reported 67% reduction in outages compared to other areas within PG&E's territory. The year concluded with no significant safety events.

Customer Satisfaction Score, CEMI, SAIDI
Coordinate work to minimize planned outages, reduce restoration time, and increase customer satisfaction.

2024 Mega Bundled Work Results

Work Type	Customer Outage Minutes Saved	Customer Avg Outage Duration Reduction (CAIDI)	% Reduction in Planned Outages
Pole Replacement	3,190,119	37.11	47%
Overhead Replacement	774,399	30.57	43%
Corrective Tags	660,907	9.04	84%
Combined	**4,625,425**	**34.91**	**67%**



Production System – Throughput Improvements
Enable throughput improvements by reducing unit costs as compared to non-bundled work: realized 20-30% construction unit cost reduction in 2024

2024 Mega Bundled Work Results

Work Type	Units Complete	Unit Cost Reduction
Pole Replacement	2673	17%
Overhead Replacement	970	20%
Corrective Tags	4591	24%
Combined	**$17,978,726 Saved**	

Figure 13: Key Performance Indicators for the 2024 Mega Bundle Program

Financially, PG&E reported that the program resulted in cost savings. As summarized above, pole replacement costs decreased by nearly 17%, overhead replacements by 20%, and resolution of EC-Tags by 24%. PG&E attributes approximately $18 million of cost savings to the 2024 Mega Bundle Program.

For 2025, the program expanded to consider 19,860 open EC-Tags over 21 circuits. After undergoing the 10-step process described above, the final 2025 Mega Bundle Workplans were finalized to address 16,891 open EC-Tags. The reduction from 19,860 to 16,891 tags (2,969 total) was primarily related to concentration, where PG&E stated that a targeted number of poles/tags per mile is used to ensure that tags are located relatively close to one another thereby enhancing the efficiency and logistics of repair efforts. A higher concentration of tags means fewer staging yards and less drive time for field personnel.

Table 12: Preliminary, Excluded, and Final 2025 Mega Bundle Tag Breakdown by MAT Code

Maintenance Activity Type (MAT)		Draft	Priority of Excluded Tags & Total					Final
CODE	DESCRIPTOR	Plan	B	E	F	H	Total	Plan
07C	Tree Attachments	387	-	46	-	19	**65**	**322**
07D	Degraded Pole Replacements	9,760	-	1,253	33	439	**1,725**	**8,035**
07O	Overloaded Pole Replacements	94	-	11	-	1	**12**	**82**
2AA/KAA	Overhead Notiications	9,452	-	638	199	284	**1,121**	**8,331**
2AE/KAF	Overhead COE Notifications	5	-	-	-	-	**-**	**5**
2AF	Idle Facilities Removal	151	-	14	28	4	**46**	**105**
49T	Overhead Protection Program	2	-	-	-	-	**-**	**2**
GAC	Pole Analyze Loading	1	-	-	-	-	**-**	**1**
KAQ	Streetlight Burnouts	8	-	-	-	-	**-**	**8**
	Totals:	**19,860**	-	1,962	260	747	**2,969**	**16,891**

PG&E provided the ISM with a listing of excluded tags by MAT[70] code and tag priority for the 2025 Mega Bundle Workplans. As shown in Table 12, the 2,969 excluded tags were all priority E, F, and H with over half being pole replacement tags.

The ISM participated in a field review of one of the larger Mega Bundle projects for 2025 with 1,714 open EC-Tags. In preparation, the ISM reviewed the excluded tag list for the circuit which totaled six. PG&E reported that the excluded tags were originally B-Tags that were subject to a B-tag backlog catch back plan (described above), and therefore not originally included in the 2025 Mega Bundle Workplan. However, subsequent inspections downgraded the tags to a priority "E". The timing of the "down grade" resulted in the tags being excluded from the 2025 Mega Bundle Program. PG&E reported that tags excluded from the 2025 Mega Bundle Workplans will be handled as part of PG&E's routine maintenance program.

The 2025 Mega Bundle projects commenced on April 1, 2025 with a targeted completion date of September 30, 2025. PG&E estimated that the final 16,891 tags represent approximately $200 million worth of work (approximately 2x the value of the 2024 Mega Bundle program). PG&E also estimated that the 2025 customer outage reduction will be similar to 2024. PG&E anticipates the continued evolution of the Mega Bundle Program, with 50,000 open EC-Tags preliminarily planned for 2026. The ISM will continue to monitor the Mega Bundle Program and report on material observations.

Mega Bundle Field Observations

PG&E hosted the ISM for a review of a Mega Bundle Project managed by PG&E and executed by two affiliated utility contractors.

<u>Orientation and Initial Discussions</u>

Field observations began at a laydown yard where the General Foreman led a safety tailboard. The planned outage affected 11 customers, all notified in advance. Due to R5 wildfire risk, crews used trailer-mounted water tanks ("water buffalos") for fire mitigation. The yard supported deployment for the 1,714 EC-Tag Mega Bundle project and housed replacement

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[70] MAT Codes are used by PG&E to categorize and track various maintenance activities related to operations.

materials, disposal areas, and equipment shared with a system hardening initiative.

Contractors outlined three job sites involving the replacement of seven power poles and close-out of three EC-Tags. PG&E stated that pre-drilled holes, completed by a third-party due to rocky terrain, help reduce project risk and shortens customer outage durations by more than 50%.

First Job Site

At the first site, crews replaced two poles and closed out three EC-tags addressing hardware issues, woodpecker damage, and vegetation pruning. PG&E conducted a safety tailboard, and traffic control was in place. One pole, located on private property, required a utility tracked vehicle (UTV) to lift and install the new pole. Linemen performed hardware and conductor removal/reinstallation by climbing the pole. As previously mentioned, the replacement was set into a pre-drilled hole prepared by a third-party contractor.

Second and Third Job Sites

At the second site, crews replaced two poles with bucket truck access. Crews completed one pole prior to the ISM's arrival; the second was staged with crossarms and hardware installed. PG&E used a water buffalo for fire mitigation and pre-drilled the replacement hole.

The third site involved replacing three poles on steep terrain. Crews pre-drilled replacement holes in advance, and the UTV from the previous job site, stabilized with built-in hydraulic supports, was positioned to place gravel in the hole. PG&E kept a water buffalo present for fire risk mitigation, and pre-construction activities were underway.

The photographs in Figure 14 below provide a representative overview of the work performed and observed during this site visit.

Figure 14: Representative Mega Bundle Field Observations

Mega Bundle Project Close-out

After site visits, the ISM met with PG&E and contractor staff to review the close-out process. Upon completing work, foremen submit documentation and photos to the contractor's QA/QC team for verification. PG&E then conducts either a desktop review using photos or performs a field inspection. PG&E stated that the number of field inspections increase as the Mega Bundle project progresses. Most discrepancies are documentation-related, such as incomplete forms or mischaracterized repairs, and are typically resolved through desktop reviews before final close-out. PG&E stated that there is a high level of cooperation to ensure alignment with project standards and resolve any issues prior to final approval.

Routine Distribution Maintenance Field Review

During the current ISM reporting period, the ISM shadowed a distribution maintenance crew performing routine EC-tag repair work. The field review was intended to provide visibility into the full maintenance process from work assignment through load-out, deployment, execution, and close-out.

Emergency Tag Maintenance Field Observation

The ISM's site visit started at a service center which included safety briefings, introductions, and work assignments. Emergency tags from the prior night led to adjusted assignments, with a five-person crew tasked with an A-Tag repair. The foreman of the 5-person crew explained that the A-Tag assignment was the result of an outage to commercial customers caused by failed transformers. A troubleman, dispatched to the outage, initiated the EC tag process. Because the repair work involves the replacement of transformers, the on-call supervisor engaged an estimator who, in turn, performed a load study, which led to a transformer upgrade.

Crews replaced two transformers and added crossarms to conform to PG&E's current construction standards and eliminate vertical dead-end construction. The crews found no visible cause for the outage; however, the troubleman's report indicated a likely bird contact incident. Prior to reconnection, crews field-tested transformer voltage to confirm proper operation. The foreman coordinated with commercial customer electricians to prepare for re-energization, after which the transformers were re-energized by closing the cutouts. The following photographs show the defective transformers and required upgrades, the project loadout, and completed work.


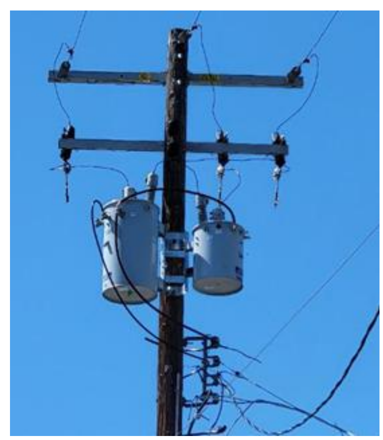

Figure 15: Representative Routine Maintenance Field Observations (A-Tag, Project Load-Out, and Completed Project)

After completing the A-Tag repair, the foreman described PG&E's close-out process: 1) Emergency Construction Package forms are completed in hard copy, 2) reviewed and approved by the supervisor, and 3) forwarded to the clerk for entry into SAP and then forwarded to mapping for GIS updates and creation of as-built drawings.

TRANSMISSION TRENDS, INSPECTIONS AND INFRASTRUCTURE

During the current ISM reporting period, the ISM reviewed PG&E's transmission system performance and mitigation efforts in support of the company's WMP goals. The review focused on outage and ignition trends, updates to inspection protocols and tagging guidance, and programs to assess and mitigate risks associated with aging steel structures. The following summarize the ISM's observations in each of these areas related to risk reduction, reliability, and compliance.

Transmission Outage and Ignition Trends

During the current ISM reporting period, the ISM reviewed PG&E's transmission outage data through July 31, 2025. Transmission outages continue to represent a small fraction of PG&E's overall electric outage profile. Based on PG&E's internal outage tracker, transmission outages have accounted for approximately 0.3% to 0.5% of sustained outages since 2019, despite transmission-related ignitions historically comprising approximately 8% of total ignitions. This indicator highlights the relatively lower frequency of transmission outages compared to their potential wildfire consequence.

PG&E's sustained transmission outages by basic cause are shown in Figure 16. Note that these outages are not weather normalized, with some of the annual variability due to the changing frequency of more extreme weather in any year. The variability in environmental-caused outages, for example, is driven by the number of lighting- and forest fire-caused outages that occurred each year.

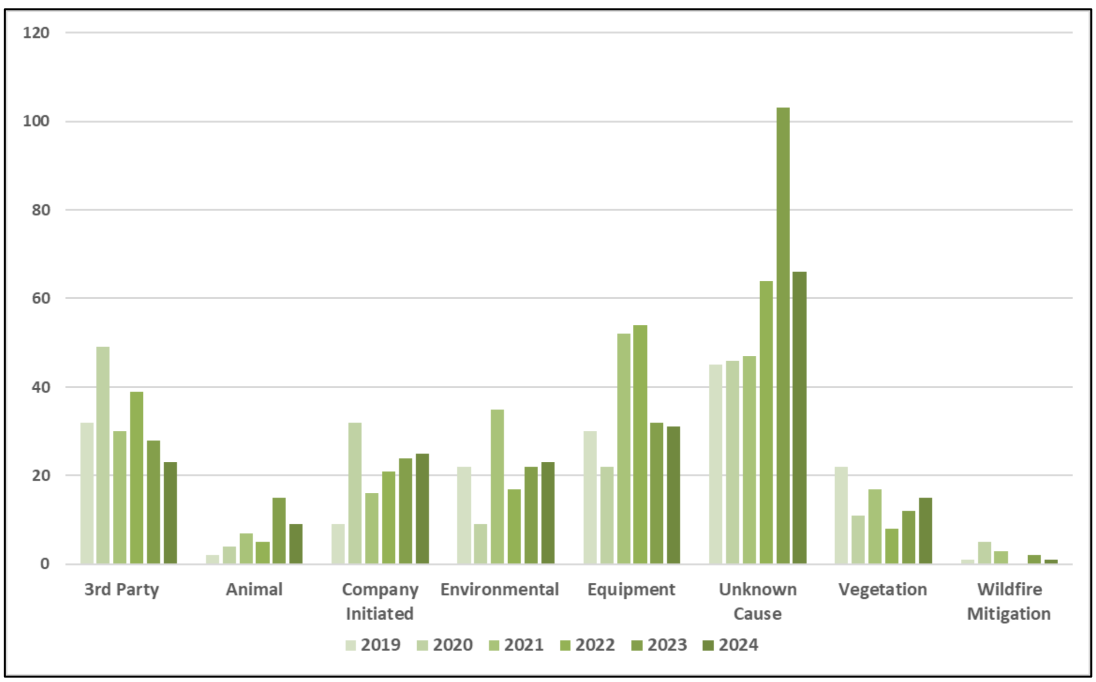

Figure 16: Transmission Sustained Outages (Excluding MED) 2019 to 2024 by Basic Cause

While vegetation-caused transmission outages remained stable over these six years, increasing trends were seen in animal- and equipment-caused outages (detailed further below). 'Unknown' caused outages are listed with the highest frequency. The ISM notes that in 59% of these unknown outages over these six years, no patrols were undertaken to assist in cause identification. This percentage of no-patrols increased to 71% in 2023, which can be reflected in the data with the high number of unknowns in 2024 seen in Figure 16. Without these patrols, PG&E may be unable to determine cause. Company-initiated outages are also increasing over time. These types of outages include planned outages for construction and maintenance activity, with the number of these outages increasing from three to nine from 2019 to 2024.

In addition, the ISM examined component-level failure data for transmission assets in HFTD areas. Between 2018 and 2024, insulators and conductors accounted for 77% of equipment-related outages, with insulators contributing the highest number of failures, followed by conductors, jumpers/hardware, and wood poles. The asset failure by component type in HFTD is shown in Figure 17 below.

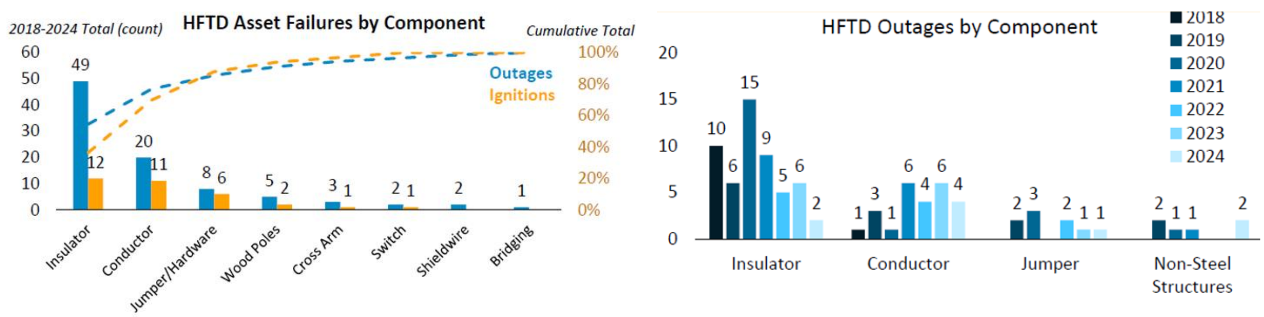

Figure 17: Asset Failure and Outages by Component Type in HFTD

Outage trends by component show that insulator-related outages decreased in the past three years, while conductor-related outages remained relatively steady since 2021 as shown in Figure 16 above. PG&E notes that conductor failure modes are more difficult to visually assess, which may contribute to under-identification during inspections. PG&E stated that it implemented hardening efforts to address these risks, including the installation of shunt splices, dampers, and conductor segment replacements.

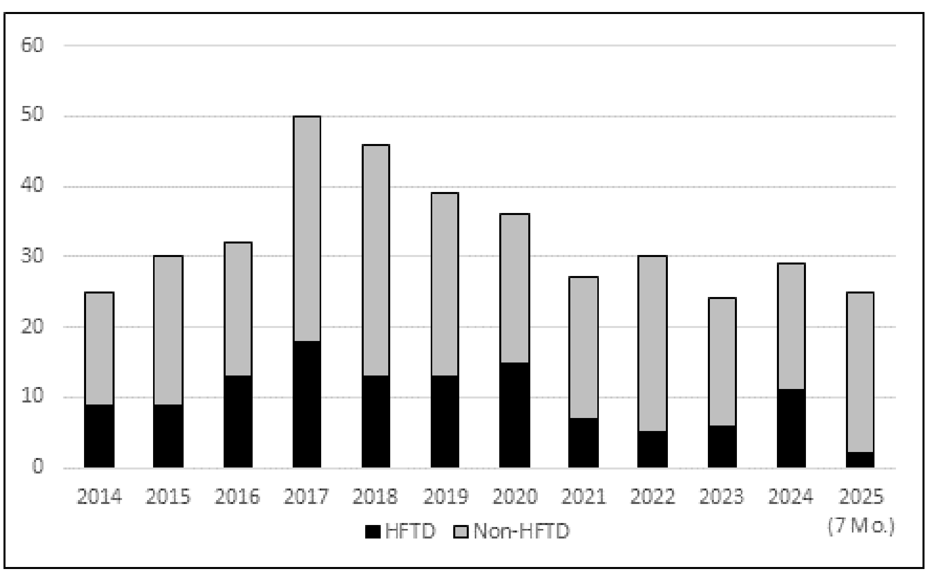

Figure 18: Total PG&E Transmission Ignitions by Tier (2014 to July 2025)

As seen in Figure 18, PG&E reported 24 total transmission ignitions during the first seven months of 2025.

Nineteen of these ignitions were CPUC reportable, and three occurred in HFTD during the first seven months of 2025. This compares favorably with the eight CPUC reportable ignitions PG&E experienced in 2024 in HFTD, five of which were during the more extreme R3+ FPI conditions, all of which were caused by bird-contact. Over the 2014 to July 2025 period, bird contact was the most frequent cause of CPUC reportable transmission ignitions (37%), followed by equipment caused ignitions (32%).

In addition to installing bird guards on high outage circuits each year under its Avian Protection Plan, PG&E is piloting the installation of dielectric "frog covers[71]" on a 115kV circuit, which ranks highest in bird-related wildfire risk. As noted in the Risk Tracking and Risk Mitigation Section of this ISM Report 7, PG&E is also in the process of evaluating the use of transmission tower attributes (like impaired clearance) and distance to water as inputs to the transmission avian probability model.

Inspection Program Overview

During the current ISM reporting period, the ISM reviewed PG&E's transmission inspection program updates, including changes to inspection protocols, tagging guidance, and supporting documentation. These updates reflect PG&E's ongoing efforts to refine its asset condition assessment and prioritization processes.

PG&E's inspection procedures are governed by the Electric Transmission Preventative Manual (TD-1001M), which outlines patrol, climbing, ground, aerial, and underground inspections, as well as activities performed by the Transmission CIRT. Within this framework, job aids serve as key tools for inspectors, providing condition examples and guidance for assigning LC tags.

In 2024, PG&E discontinued the use of Condition Codes (rated 1 through 5). In 2025, PG&E transitioned from the use of B tags to a revised tagging system that includes priority A, E, and F tags. E tags are now subdivided into short-duration categories of 3, 6, 12, and 36 months, as defined in PG&E's Electric Transmission Line Guidance for Setting Priority Codes (TD-8123P-103). Several components listed in this guidance include footnotes recommending 3-month durations for specific E tag conditions. PG&E confirmed that 3-month duration conditions are consolidated in training materials and job aids and are verbally emphasized during inspector training. Missed identification of these conditions is considered a "Critical Attribute" miss and is tracked against PG&E's QC & QA pass rate targets under the WMP. Missed identification of longer E tags is not considered a "Critical Attribute."

PG&E updated 12 of its 22 transmission job aids in 2025. These updates included revisions to job aids for Steel Structures and Supports, Wood Poles, Hardware and Insulators, Animal Guards, Work on Bird Nests, Clearance Conditions, Transmission Foundation Conditions, Guys and Anchors, Splices, Connectors, Dampers and Spacers, Line Switches, Vegetation

[71] R3+ Cause Evaluation CAP #9 is discussed further in the Risk Tracking and Risk Mitigation section. The term "frog cover" typically refers to a protective covering designed to safeguard electrical components from external elements, particularly wildlife interference.

Nonconformances, and a newly introduced job aid for Marking, Numbering, and Debris Removal. PG&E did not revise the remaining job aids covering idle lines, infrared inspections, shield wires, and underground assets during this cycle.

A key enhancement across the updated job aids was the integration of FSR guidance. FSR allows inspectors to reassess previously identified conditions and document any changes over time. The CIRT team then assigns appropriate compliance due dates based on the reassessment. PG&E also added guidance on when to assign short-duration E tags for specific condition examples. In many cases, PG&E reclassified conditions previously assigned priority F tags as requiring no notification.

PG&E increased the usability of the job aids by incorporating additional graphics, tables, and condition examples. These enhancements were designed to provide inspectors with clearer visual references and more structured decision-making tools.

Steel Structural Assessment

During the current ISM reporting period, the ISM reviewed PG&E's corrosion inspection initiatives and structural risk prioritization efforts, including the Corrosion Climbing Pilot and the Steel Structure Assessment Program. These programs are designed to identify and mitigate risks associated with aging transmission infrastructure, particularly steel towers located in HFTD.

PG&E initiated the Corrosion Climbing Pilot in 2022 to evaluate the effectiveness of climbing inspections in identifying corrosion-related issues. The pilot inspected approximately 300 structures annually, with a concentration in the San Francisco Bay Area. The pilot yielded a low find rate, with fewer than 10% of inspected structures identified for repair. Many of the issues detected overlapped with findings from PG&E's aerial detailed inspection program. PG&E concluded that the pilot did not reveal strong correlations between corrosion and either structure age or corrosion zone severity, limiting its value as a standalone program.

In 2024, PG&E merged the pilot into its Corrosion Climbing for Cause effort, which targets structures identified for potential replacement through visual inspections or engineering assessments. This integrated approach now operates under the broader Steel Structure Assessment Program, which provides detailed information to support engineering evaluations and repair decisions.

For 2025, PG&E will continue utilizing the Steel Structure Assessment Program to evaluate transmission towers with the highest risk profiles. Risk prioritization is based on a combination of factors, including:

- Asset age
- Reliability history
- Probability of failure
- Consequence of failure

These criteria guide the selection of structures for assessment and inform decisions on mitigation or replacement.

VEGETATION MANAGEMENT

PG&E's VM program is governed by internal VM Standards and Procedures described in ISM Report 6 including Routine Patrol and a Second Patrol conducted on an Inspection Cycle and a Work Cycle. In 2025, PG&E continued coordination of its specialized programs: Focused Tree Inspection (FTI), Tree Removal Inventory (TRI), and VMOM. These programs, FTI, TRI and VMOM, coordinate with Routine & Second Patrol in an effort to minimize customer touch points, increase productivity, and maximize the effectiveness of the VM budget according to PG&E. Collectively, PG&E's vegetation management programs maintain vegetation across approximately 80,000 miles of distribution overhead system.

PG&E's 2026-2028 WMP outlines the following VM commitments:

- Consolidation of Distribution Inspection Programs
- Incorporation of Remote Sensing (LiDAR, Satellite, and/or Imagery) to inform or supplement inspections in HFTD
- Utilize analytics to Risk Prioritize inspections and work execution
- Continue to execute inspections pursuant to the Vegetation Management Distribution Inspection Procedure (VMDIP) for inspection compliance

PG&E reported that these commitments are implemented through a series of coordinated vegetation management programs, each defined by distinct operational scopes, inspection protocols, and geographic boundaries.

Routine Vegetation Management & Second Patrol

PG&E's Routine VM program remains a component of its wildfire mitigation strategy. As outlined in PG&E's DVMP [72] the Routine VM activities include an annual Routine Patrol and a Second Patrol, conducted in alignment with PG&E's Inspection and Work Cycles.

During the current ISM reporting period, PG&E continued to execute vegetation work activities and prescriptions to ensure compliance with regulatory requirements.[73] Routine VM crews are expected to adhere to PG&E's internal standards and procedures, with inspections focused on maintaining Minimum Distance Requirements (MDR) and identifying vegetation conditions that could pose a risk to overhead electric facilities.

PG&E reported that fire season timing continues to influence the scheduling of VM work execution. While electrical circuitry and associated equipment are not typically used to prioritize work within project areas, PG&E described pre-work coordination meetings with vendors to discuss mitigation of Priority 1 and Priority 2 trees, cost-effective planning, and resource utilization. Execution of tree work activities remains the responsibility of contracted vendors.

Whole tree removal continues to be PG&E's preferred mitigation strategy when vegetation hazards are identified, as opposed to targeted pruning. PG&E is required to mitigate tree

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[72] Distribution Vegetation Management Program Utility Standard TD-7102

[73] General Order 95, Rule 35, and California Public Resource Code Sections 4292 and 4293.

related hazards that may impact overhead electric facilities according to GO 95, Rule 35. Whole tree removal is often completed and is preferred according to PG&E versus targeted pruning to mitigate the electrical hazard as identified.

Vegetation Management QA and QC

PG&E's vegetation management oversight includes both QA and QC functions, each with distinct roles in supporting compliance and operational effectiveness.

A single PG&E Director oversees both QA and QC functions. PG&E maintains a separation of duties between inspection and tree work vendors, preventing any QA or QC vendor from performing vegetation mitigation work within a 12-month period. The ISM currently has visibility into the QC system of record and continues to monitor attributes associated with vegetation points related to Vegetation Management Inspector (VMI) and VM vendor-completed work.

Quality Control

The QC group is comprised of internal PG&E employees and two contract vendor companies. QC inspectors are responsible for evaluating the quality of vegetation work performed with a focus on adherence to PG&E's scope of work and compliance with MDR. QC VMIs do not delist prescriptions or confirm tree strike potential to PG&E facilities; however, they may add "missed" trees to the system of record when identified.

In 2025, PG&E reported that QC is on track to exceed 85,000 locations, with a pass rate of 95 percent. As of October 14, 2025, QC reviewed approximately 83,400 spans achieving a pass rate of 99.2% systemwide. QC inspection represented approximately 16 percent of the completed work population for distribution vegetation management during the reporting period.

Quality Assurance

QA responsibilities include ensuring regulatory compliance with General Order 95, Rule 35 and California Code of Regulations Title 14, California Public Resource Code (PRC) 4292 & 4293. The QA group consists of internal PG&E staff and a single vendor. QA inspectors do not delist prescriptions, but may escalate systemic concerns to vegetation management leadership. Similar to QC, QA does not confirm strike potential; however, missed trees are documented as findings.

QA inspections are conducted on a representative sample of completed work in HFTD, and are selected from QC-reviewed locations. While QA performs fewer overall inspections, their inspections assess both the original inspection and the QC review.

ANSI-A300 Compliance/Best Management Practices (BMP)

The ISM continues monitoring PG&E's VM practices through field assessments. The ISM observed no substantive change in pruning practices associated with ANSI-A300 Standards and BMPs during the current ISM reporting period. ANSI-A300 and BMPs are intended to minimize re-growth towards the conductor and encourage the re-direction of tree growth. This is designed to maintain MDR and move proactively to reduce incompatible species that will require future pruning and reduction of tree density. While the ISM performed a lower number of Level 1 assessments in the current ISM reporting period, the percentage of hazard trees/radial clearances identified relative to those assessments doubled as compared to the trees identified in ISM Report 6.

Table 13: Summarized ISM Field Observations of Conformance to ANSI-A300 and BMP

Attribute	ISM Report 6	Current ISM Reporting Period[74]
Hazard Tree & Radial Clearance (Percentage of Assessments)	112 (0.8%)	32 (1.6%)
Observation Trees[75] (Percentage of Assessments)	43 (0.3%)	9 (0.5%)
Number of Level 1 Assessments	14,238	1,993
Number of Spans Inspected	839	4,856
ANSI-A300/BMP non-compliant spans (Percentage of spans)	418 (50%)	205 (4%)

Vegetation Management for Operational Mitigation

PG&E's VMOM aims to help reduce vegetation-related outages and potential ignitions based on historic vegetation outages on EPSS-enabled circuits. The VMOM program is structured into two components: Proactive and Reactive.

VMOM projects require one of the following qualifications as outlined in the VMDIP:

- ISA Certified Arborist
- ISA TRAQ Credential
- Registered Professional Forester (RPF)
- One year of experience in VM, plus a BS Degree
- Two years of experience, plus an Associate Degree
- Three years of Utility Vegetation Management (UVM) experience

Proactive VMOM

Proactive VMOM projects are designed to address vegetation risks on distribution circuits with a history of vegetation-caused outages and tree failure. These projects are scoped at the CPZ level and are informed by PG&E's Vegetation Asset Strategy and Analytics (VASA) team.

During the current ISM reporting period, PG&E reported that VMOM Proactive efforts mitigated approximately 7,000 trees across 61 circuit segments covering roughly 860 miles, exceeding the 2025 goal of 6,500 mitigations. The reported circuit miles for Proactive VMOM reflect the total miles of CPZs where work occurred; however, mitigations were not necessarily performed along every mile within those CPZs, as efforts may have targeted specific locations.

VMIs perform Level 1 assessments to identify trees with strike potential that could impact

[74] This table shows a decrease in "Number of Level 1 Assessments" due to the ISM focusing on FTI and VMOM projects. These projects were observed in areas of lower tree density which is reflected in the increase in the "Number of Spans Inspected" compared to previous reporting periods. See Focus Tree Inspection section for additional information.

[75] Observation trees are potential Hazard Trees or Radial Clearance conditions that ISM could not confirm due to access restrictions such as posted property, locked gates, fences, etc.

overhead electric facilities. If the VMI suspects a tree with defects or site conditions contributing to potential tree failure within a 15-month timeframe, a Level 2 assessment is performed.[76]

PG&E's VMOM CPZ selection criteria must meet one of the following on EPSS-enabled distribution circuits:

- Two or more vegetation-caused outages in 2024.
- Three or more vegetation-caused outages from 2022–2024, with at least one in 2024.
- One or more vegetation-caused outage in 2024 affecting more than 1,000 customers.
- A vegetation-caused outage in 2024 on a circuit where customers experienced five or more interruptions.

The ISM conducted field observations on two VMOM Proactive projects and noted the following:

- Multiple touch points occurred within a 10-day period where both Routine Patrol and Proactive VMOM crews inspected the same circuit segment.
- Inconsistencies in assessments between VMIs from different programs inspecting the same trees, including:
    - Inconsistencies between VMIs conducting inspections for different VM programs on the same tree with defects warranting a Level 2 assessment or entering a prescription for work as required in the VMDIP.
    - Instances where VMIs differ in their decision to prescribe work as required in the VMDIP.
    - Instances where pruning is prescribed in areas of low tree density in lieu of tree removal in remote locations requiring repeated maintenance efforts.
    - Prescriptions for pruning were created where actual conductor clearance exceeded prescribed threshold.[77]

[76] Level 1 (limited visual) assessment from one perspective which typically focuses on identifying trees with imminent and or probable likelihood of failure (i.e. Hazard Tree). Level 2 (Basic) is a 360-degree detailed visual inspection of the tree and its site.

[77] Prescriptions were issued for vegetation located beyond clearance thresholds that did not have potential to encroach within the following pruning cycle.

Figure 19: Representative VMOM Proactive Project Field Observations (Tree Approaching MDR With No Prescription in the System of Record)

Reactive VMOM

Reactive VMOM projects are initiated following vegetation-related EPSS outages or ignitions. These projects are informed by PG&E's PIIRs,[78] which may result in the development of CAPs. Post-incident inspections begin at the subject tree and extend at least five spans in all directions. Level 2 assessments are performed on the tree associated with the outage, while surrounding trees receive Level 1 assessments. If additional defects or site conditions are identified on any of the surrounding trees, further Level 2 assessments are conducted.

PG&E reported that not all post-incident inspections are performed by ISA Certified Arborists or TRAQ credentialed personnel. Some inspections are conducted by individuals with arboriculture experience, but it is not a requirement.

The ISM reviewed PG&E text from the PIIRs associated with VMOM Reactive projects and noted the following comments within the PIIRs:

- Trees in "Constrained" status that failed prior to work execution[79]
- Trees missed during Routine or Second Patrol that could have been identified[80]
- Trees in "Pending" status at time of failure[81]

[78] The ISM reviewed PIIR reports and noted instances where trees identified for mitigation but had not been mitigated and were the root cause of the outage or ignition.

[79] Tree was identified as a hazard tree and was prescribed for removal prior to failure. (Ignition 20240826)

[80] Ignition 20241124

[81] Pending refers to a tree where PG&E issued work to the tree vendor, but the work has not started. (Ignition 20240428)

- Trees exhibiting defects not expected to be identified by Level 1 assessment[82]
- Tree mortality post inspection

In 2024, "Reactive VMOM" mitigated approximately 2,300 trees which were involved in vegetation caused EPSS outages or ignitions.

Focus Tree Inspection

PG&E's FTI program prioritizes vegetation management efforts on electric distribution circuits with elevated risk profiles based on Areas of Concern (AOCs) which incorporate historical outage and ignition data, tree species, failure types, and vegetation density.

The AOC process developed by the VASA team is supported by PG&E's WDRM v4. This model incorporates ignition and outage data from 2015 through 2022 and evaluates risk at the CPZ level within HFRA. In 2025, PG&E updated its modeling approach to include areas with high wildfire risk but low tree density, ensuring that sparsely vegetated areas that are still high risk are not overlooked. During the current ISM reporting period, the ISM observed some of these known tree density areas shown in Figure 20 below. AOCs may extend beyond HFRA or HFTD boundaries.

Figure 20: Representative Field Observations of Areas with High Wildfire Risk but Low Tree Density

During the current ISM reporting period, PG&E established an inspection target of approximately 1,500 circuit miles for 2025, based on risk scores generated in October 2024. As of this report, PG&E completed inspections on approximately 1,400 miles. In 2024, PG&E completed 1,570 miles under the FTI program. Approximately 2.1 million vegetation points have been created under the FTI program. Year-to-date the FTI program mitigated approximately 41,000 trees.

[82] Ignition 20241773

The ISM noted that PG&E's FTI program includes areas that are undergoing or have recently undergone undergrounding, yet coordination with vegetation management activities appears limited, resulting in work being performed on circuits that are transitioning or have already been undergrounded. In addition, PG&E provided the ISM with the current year's FTI map, which includes circuit miles that have already been undergrounded. PG&E stated that it claims the full AOC mileage for reporting purposes, though the ISM is not aware whether PG&E continues to perform inspections on undergrounded miles as part of the FTI program.

Three inspection roles support the FTI program:

- VMI: Conducts inspections and must hold an ISA Tree Risk Assessment Qualification (TRAQ) credential.
- QC: Performs 100% quality control reviews of completed FTI projects and reports findings to VM operations. TRAQ credential required.
- QA: Verifies regulatory compliance and may issue formal recommendations. QA inspectors require TRAQ credentials when reviewing FTI spans, and may escalate findings to VM leadership.

FTI inspectors perform Level 2 assessments for each tree on an FTI inspect segment, during which VMIs should identify every tree with strike potential to PG&E's electric facilities, excluding service drops. These vegetation points may include hazard trees, radial clearance conditions, or inventoried trees.[83]

PG&E VM leadership stated that after the initial Level 2 assessment under FTI, subsequent Routine Patrols on those same lines default to Level 1 unless a change in condition warrants a reassessment. However, the system of record is not always updated to reflect these follow-up Routine or Second Patrol inspections. Specifically, if an inventoried vegetation points is not modified during an inspection, the system retains the original creation date without documenting the reinspection. PG&E's VMDIP states: "If a record already exists in the system of record, THEN UPDATE the record to the current required prescription."[84]

The ISM also observed instances system-wide where trees were entered into the system of record as inventory trees despite lacking strike potential. According to the VMDIP, the FTI program is intended to focus on trees with a probable likelihood of failure within a 15-month timeframe, excluding service drops.

During the current ISM reporting period, the ISM conducted field assessments across 17 AOCs in five regions and nine counties within PG&E's electric service territory. These assessments provided additional insight into the implementation of the FTI program and the consistency of inspection practices.

Tree Removal Inventory

PG&E's TRI program continues to address vegetation risks associated with trees previously

[83] Inventory trees are trees that meet strike potential criteria but exhibit no structural defects at the time of inspection.

[84] PG&E Distribution Inspection Procedure TD-7102P-01-Att07, Rev 3, effective 04/28/2025, pg. 2

identified under the now-discontinued Enhanced Vegetation Management (EVM) program. These trees were originally assessed using PG&E's Tree Assessment Tool (TAT) or through EVM inspections conducted between 2019 and 2022.

PG&E distributed approximately 192,000 TRI vegetation points within associated work plans for review. Of these, PG&E inspected approximately 142,000 trees between 2023-2024, and mitigated 32,500 trees under the TRI program in 2024. PG&E stated that it mitigated approximately 19,000 trees year-to-date in 2025, contributing toward the 25,000-tree mitigation target outlined in PG&E's 2025 WMP. Since the discontinuation of the EVM program, PG&E mitigated approximately 94,000 trees under TRI-related efforts.

PG&E indicated that trees within the TRI inventory with a mitigation status of "other than Abate" are subject to reassessment by a VMI.[85] If the VMI determines that the tree may not impact PG&E facilities, the tree must be further evaluated by an ISA Certified Arborist with a TRAQ credential. PG&E stated that trees previously assessed as "TAT Abate" will be removed without reassessment if overhead conductors remain present, unless the tree is part of the TRI Pilot Project described below.

The TRI program will continue until PG&E mitigates all inventoried trees identified under the EVM program. As of the current ISM reporting period, TRI functions primarily within Field Maps, though visibility is available in OneVM; and PG&E has not confirmed whether TRI will be fully migrated into the OneVM platform.

Table 14: TRI Program Activity for 2025

TRI Program Summary	Count
TRI Trees removed in 2025 (includes worked through other VM programs)	14,072
TRI Trees removed in 2025 through the TRI program	6,971
TRI Trees reassessed by TRAQ Arborist	5,397
TRI Trees removed "TAT Abate" without reassessment	17
TRI Trees removed that were reassessed by TRAQ Arborist[86]	442

TRI Pilot Project and Marked Tree Inventory

PG&E initiated the TRI Pilot Project in June 2024 to reassess vegetation points previously classified under the TAT as "Abate," "Do Not Abate," or "Other". The objective of the pilot is to evaluate the accuracy of prior assessments and refine mitigation prescriptions based on updated field conditions and arborist evaluations.

Under the pilot, PG&E reassessed approximately 8,400 trees. In 2024 PG&E reported that reassessment staffing included 38 ISA Certified Arborists with TRAQ credential and five Board Certified Master Arborists, comprising both internal personnel and external vendors.

Within select locations for the TRI Delisting Pilot program there are 43 ISA Certified Arborists with TRAQ credential and 13 ISA Board Certified Master Arborist (BCMA) with TRAQ

[85] "other than abate" means that the trees did not receive an "Abate" designation.

[86] Of the 5,397 trees reassessed by a TRAQ-certified arborist, 442 were removed.

credential. The Certified Arborists conduct the initial reassessments, while any recommendation to delist a tree requires evaluation and confirmation by a BCMA.

The TRI Pilot Project is supported by the MTI initiative, which is currently being conducted in one county within PG&E's service territory. MTI expands upon the TRI Pilot by requiring annual Level 2 assessments of previously TAT trees located in HFRA until mitigation or formal delisting is completed. MTI incorporates a system of record that includes GPS coordinates, assessment dates, reasons for delisting, and an auditing process to ensure traceability and verification. The Marked Tree Inventory (MTI) program consists of 43 ISA Certified Arborists with TRAQ credential and 13 BCMAs also part of the delisting process.

PG&E stated that data collected through MTI will inform future TRI reassessment efforts and support broader vegetation risk modeling. As of this reporting period, PG&E has not confirmed whether TRI or MTI will be fully integrated into the OneVM platform. Table 15 shows the summary of the TRI Pilot Project which includes 55% of the trees delisted after reassessment.

Table 15: TRI Pilot Project Summary

TRI Pilot Summary	Count
TRI Trees Reassessed by TRAQ Arborist	8,873
TRI Trees Removed (TAT Abate without reassessment)	824
TRI Trees Removed after Reassessment by TRAQ Arborist	299
TRI Trees Recommended for Delist after Reassessment	4,917
TRI Trees Pruned	125
TRI Trees Removed by other programs at time of reassessment by TRAQ Arborist	2,170

Constraints Process

PG&E's vegetation management constraints process is designed to identify and manage conditions that prevent the timely execution of prescribed vegetation work. During the current ISM reporting period, the ISM reviewed PG&E's constraints tracking and resolution practices, including coordination between the Constraints Group Management team and PG&E's operational regions.

A constraint is initiated when a prescription is created by a VMI or shortly thereafter. PG&E stated that there is no defined time limit for how long a prescription may remain in "constrained" status. It will remain constrained until it is resolved or when the inspection process escalates the priority of the work. PG&E leadership indicated that a change in condition to Priority 1 or Priority 2 will prompt expedited resolution.

The Constraints Group Management team is responsible for tracking and reporting constraints, while PG&E's regional teams are responsible for resolving them. PG&E maintains five distinct constraint categories:

- Biological & Cultural[87]

[87] VM Riparian Review Procedure TD-7102P-16 and VM Bird Nest Procedure TD-7110P-01

- Environmental Permitting[88]
- Encroachment Permitting[89]
- Customer Interference[90]
- Operational (circuit adjustments, weather impacts, etc.)[91]

PG&E reported that constraints are tracked by program type and remain active until resolved.

Table 16: Current Constraints by Program[92]

Constraint Group	FTI	Other	Distribution Routine & Second Patrol	Transmission Routine & Second Patrol	VMOM	Grand Total
Biological & Cultural	1,765	9,840	11,483	1,198	54	24,340
Customer	2,705	7,926	17,487	1,209	331	29,658
Encroachment Permitting	2,239	3,403	27,320.5	400	324	33,866.5
Environmental Permitting	6,100	11,490	45,441.5	1,372	794	65,197.5
Operational	887	37,865	7,639.9	1,971	135	48,497.9
Grand Total	13,696	70,524	109,371.9	6,150	1,638	201,379.9

OneVM

PG&E's OneVM platform serves as the centralized system for vegetation management work planning, coordination, and execution. The platform integrates GIS capabilities to support project creation, constraint case management, and work closure activities. PG&E began transitioning vegetation management programs into OneVM in 2023 as stated in ISM Previous Reports, with full integration expected to occur over multiple years.

During the current ISM reporting period, PG&E reported continued progress toward consolidating vegetation management programs into OneVM. Digitized TRAQ forms became available in March 2025.

PG&E continues to migrate vegetation management programs into OneVM, though several components remain in legacy systems. The following is an update on the migration for a few key VM programs:

- QC: Expected to be fully migrated into OneVM in 2026.
- Transmission: Resides in Survey123, with plans for future migration.
- QA: Resides in Survey123/ArcGIS, with no current plans for migration.
- TRI: Visible in OneVM but continues to function primarily within Field Maps.

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88 VM Distribution Inspection Procedure TD-7102P-01

89 VM Encroachment Permitting Procedure TD-7102-31

90 Addresses customer-related access issues (VM Distribution TD-7102-04 & Transmission Interference Procedure TD-7103-07)

91 VM Line Clearance Request Procedure TD-7102P-15

92 The decimals in this table represent units of "brush" trees in constrained status.

PG&E leadership indicated that a business requirements review is underway to assess the feasibility of migrating TRI into OneVM. PG&E's long-term objective is to consolidate all vegetation management activities into two core proactive inspection programs: Routine and Hazard Tree Patrol. If migration is deemed infeasible, these programs will continue to operate and be maintained in Field Maps as the system of record.

Vegetation Management Contracts

During the current ISM reporting period, PG&E reported that it revised its vegetation management tree work contract effective 2023 with an extension through 2026. PG&E transitioned to a unit price contract model in 2023 for vegetation work activities, replacing previous contract terms that relied more heavily on time and material.[93] The revised contract includes provisions for fixed-price or lump-sum negotiations in cases where work falls outside the scope of defined unit types.

PG&E reported the new contract structure intends to improve cost efficiency, enhance vendor resource retention, and reduce safety-related incidents.

The contract includes the following unit types:

- Aerial Pruning
- Brush Work
- Fell Tree
- Dismantle Tree
- Wood Management
- Environmental Clearance and Line Clearance Tags

To account for geographic variability, PG&E implemented a divisional bid component, allowing vendors to tailor bids based on local terrain and work conditions across 25 divisions across six regions.

PG&E reported that multiple prime VM contractors operate system wide. PG&E leadership stated that the revised contract limits subcontracting to an agreed upon percentage, a change from prior agreements that placed no restrictions on subcontractor usage. PG&E told the ISM that they observed a decrease in safety-related incidents following the implementation of this limitation, though PG&E acknowledged that this reduction may also be influenced by concurrent changes to internal safety protocols.

The ISM will continue to review PG&E's vegetation management contracts.

[93] Time and Material contracts compensate vendors based on hourly labor rates and actual material costs, whereas unit price contracts pay a fixed cost per defined unit of work completed.

GAS OPERATIONS OBSERVATIONS

PG&E operates one of the largest natural gas utilities in the United States, serving approximately 4.5 million customer accounts across a 70,000-square-mile service area in Northern and Central California. The utility's natural gas system includes about 42,000 miles of distribution pipelines, 6,700 miles of transmission pipelines, , multiple compressor stations and underground natural gas storage fields, and thousands of measurement, control, and regulation stations.[94] Together, these facilities represent multiple asset classes that vary significantly in age, configuration, and condition, and form the infrastructure backbone for gas transmission and distribution across PG&E's territory.

The ISM monitors certain safety and risk aspects of PG&E's natural gas operations and infrastructure that have included corrosion mitigation, excavation damage, material and equipment failures, and overpressure events, as well as processes for leak detection and repair, integrity management, and emergency response. The ISM also observes PG&E's application of asset management practices and regulatory compliance frameworks to prioritize investments, monitor system performance, and align with federal and state safety requirements. Certain observations and programs become topics presented in the semi-annual ISM Report(s) to inform the reader of the status, evolution, and implementation of PG&E's gas safety operations and programs.

In accordance with the scope of the ISM Contract and in consultation with the CPUC, the ISM's gas operations and infrastructure focus in this ISM Report 7 is directed toward nine major categories: (1) Reported Transmission Incident Rates, (2) Distribution Maintenance, (3) Facilities Integrity Management Program, (4) Gas Clearance Operations, (5) MAOP Initiatives, (6) Damage Prevention Program, (7) Leak Survey and Leak Management, (8) First-Time ILI Projects and Direct Examinations, and (9) Corrosion Control Maintenance. These categories provide a consistent framework for reviewing PG&E's gas system safety performance and structuring ISM observations across the range of gas utility operations. Certain categories are new to the ISM Report with summary observations regarding operational and safety metrics included for informational purposes. These topics may not be included in future ISM Reports unless material changes are identified.

PG&E'S REPORTED TRANSMISSION INCIDENT RATES VS INDUSTRY

The Pipeline and Hazardous Materials Safety Administration (PHMSA), part of the U.S. Department of Transportation, is the federal agency responsible for ensuring the safe construction, operation, and maintenance of the nation's pipeline infrastructure. PHMSA establishes regulations, conducts inspections, enforces compliance, and maintains a nationwide database of pipeline safety performance. For natural gas transmission pipelines, PHMSA defines an incident as an event resulting in one or more of the following:

- a fatality or injury requiring in-patient hospitalization;

[94] https://www.pge.com/en/about/pge-systems/gas-systems.html#tabs-fc6b80548f-item-94036063d6-tab, & https://www.pge.com/en/about/company-information/company-profile.html,

- estimated property damage of $149,700 or more (as adjusted for inflation as of July 1, 2025);
- an unintentional release of at least three million cubic feet of natural gas; or
- any other event deemed significant due to its impact on public safety or the environment.

When an incident occurs, operators are required to report it to PHMSA in a standard report format, including the location, pipeline characteristics, estimated volume of gas released, response actions taken, and the underlying cause. PHMSA classifies the causes into standard categories as shown in the table below.

Category	Description
Corrosion	Leaks or ruptures caused by internal or external corrosion
Excavation Damage	Hits or strikes from digging or construction activities damaging buried pipelines
Incorrect Operation	Incidents resulting from human error, procedural lapses, or misoperation of systems
Other Outside Force	Damage from external forces other than excavation, such as vehicle strikes or dropped equipment
Material Failure of Pipe or Weld	Failures due to defects or degradation in pipe material or welds
Equipment Failure	Malfunctions of valves, compressors, or supporting equipment
Natural Force	Damage caused by natural hazards, including floods, landslides, or earthquakes
Other Incident	Miscellaneous incidents not classified in the categories above

PHMSA publishes these incidents in a database on their website.[95] The ISM utilized this PHMSA database to benchmark PG&E's historic reportable incidents per 1,000 miles of natural gas transmission pipeline against the industry, both in total and by cause. Incidents are relatively rare, therefore annual rates per 1,000 miles can fluctuate significantly due to single events. To provide a better analysis of historic trends, the ISM used PHMSA's data to benchmark PG&E against industry averages using 5-year rolling averages, which smooth short-term variability and better reflect underlying performance.

PG&E's Recent Performance

Figure 21 below shows the number of PG&E reportable incidents per 1,000 miles and the industry average reportable incidents per 1,000 miles, as well as a rolling 5-year average for each.

Between 2014 and 2018, PG&E's five-year rolling average for total incidents per 1,000 miles of pipeline consistently exceeded 0.90, where in contrast, during the same period, the industry average remained relatively stable at approximately 0.40. This placed PG&E's incident rate at more than double the industry benchmark. However, as seen in Figure 21, beginning in 2018, PG&E achieved reductions in incident frequency. By 2024, the company's five-year rolling average had declined to 0.26 incidents per 1,000 miles, closely aligned with the industry average of 0.33.

[95] Pipeline and Hazardous Materials Safety Administration. Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data. https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data

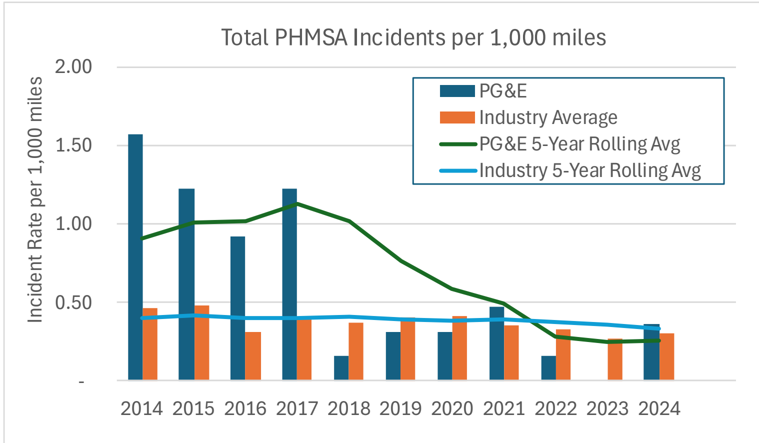

Figure 21: Total Reportable Incidents per 1,000 miles

The reduction in excavation damage incidents (of which the majority is comprised of third-party damage) is the most notable driver of this improvement, as can be seen in Figure 22. PG&E's rolling average in this category exceeded 0.50 in 2015 and 2016, compared to an industry average of just 0.05. By 2024, this figure had dropped to 0.10, narrowing the gap, driven by PG&E's reported improvements in investments in damage prevention programs, coordination with contractors, and public safety outreach as discussed in this ISM Report 7.

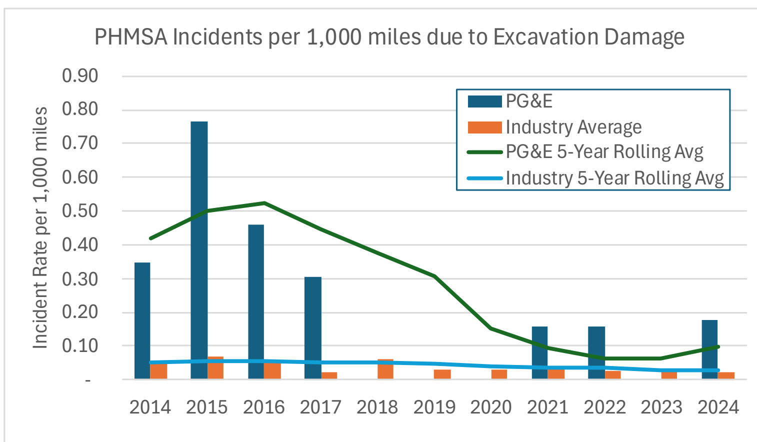

Figure 22: PHMSA Incidents per 1,000 miles due to Excavation Damage

PG&E saw changes in categories such as equipment failures and material failures of pipe or welds. The five-year rolling average for equipment failures is now below the industry average of 0.13, and material failure rates have likewise declined to levels broadly consistent with industry benchmarks as can be seen in Figure 23 below.

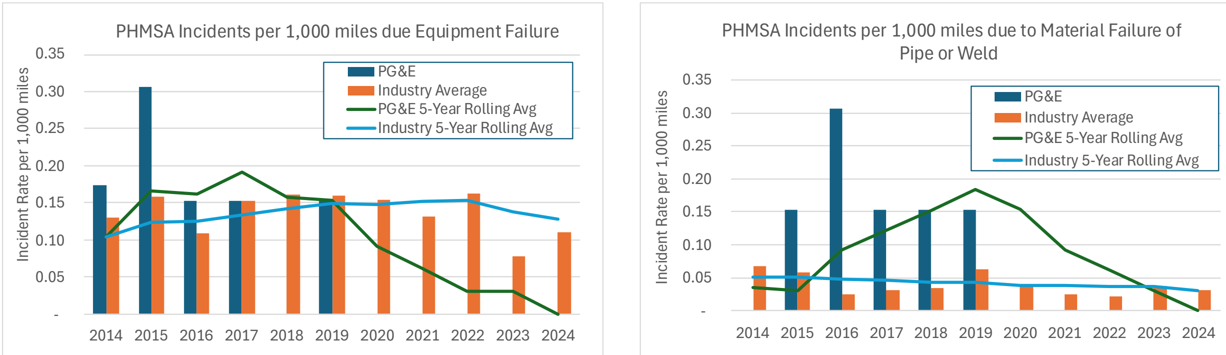

Figure 23: PHMSA Incidents per 1,000 Miles (Equipment Failure and Material Failure of Pipe or Weld)

Despite overall progress, PG&E continues to experience elevated rates in certain categories as compared with industry averages. Incorrect operation incidents remain higher than the industry average, with a rolling average of 0.10 compared to the industry's 0.03. In addition, the rolling average for other outside force damage incidents is 0.06, roughly three times the industry average of 0.02, due to some recent incidents.

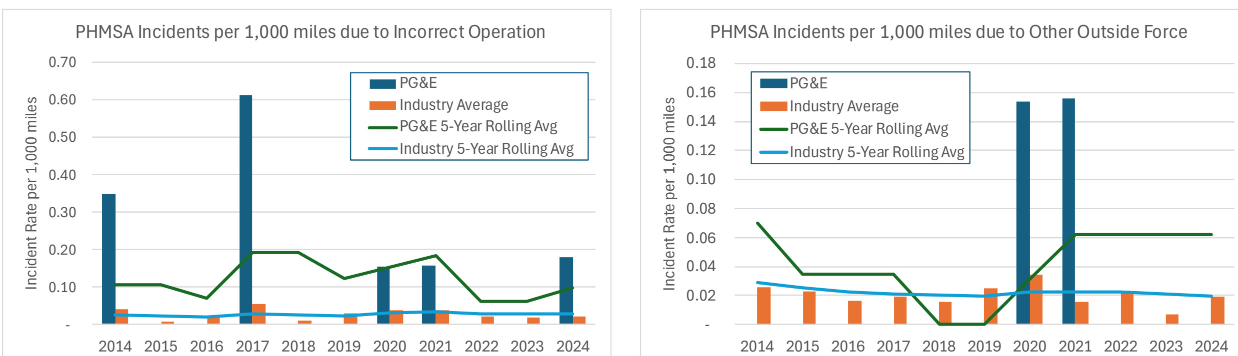

Figure 24: PHMSA Incidents per 1,000 Miles (Incorrect Operation and Other Outside Force)

PHMSA's data indicates that PG&E made progress in pipeline safety performance as related to reportable incidents in recent years. While the five-year rolling average incident rate once exceeded the industry benchmark by a wide margin, it is now nearly aligned with peer utilities. As previously discussed, transmission pipeline incidents are relatively infrequent, therefore one or two incidents in a year for one operator can increase the five-year rolling average above industry average for multiple years. However, PG&E's provided data has shown that emphasizing excavation damage prevention (comprised mostly of third-party damage) has reduced PG&E's five-year rolling average incident rate.

DISTRIBUTION MAINTENANCE

PG&E's Distribution Maintenance program addresses gas distribution mains, service lines, valves, meter sets, risers, fittings, cathodic protection (CP) equipment, and other distribution equipment. Primary work activities include service and main replacements, valve and meter maintenance, leak repairs and abandonments, preventive maintenance, emergency response to excavation damage, and leak surveys. These activities are typically initiated by conditions such as corrosion, material failures, excavation damage, incorrect operations, natural forces, or customer-reported leaks.

Workload Volumes (2022–2024)

PG&E tracks distribution maintenance activities by asset class and MAT code and provided the ISM with a summation of activities from 2022 through 2024. Figure 25 provides an overview of these distribution maintenance activities, grouped by the following activity types: corrective maintenance of service and mains, valve-related maintenance, preventative maintenance, non-recurring & meter protection work, and emergency response. Reported tasks ranged from about 15,000 to 23,000 annually, reflecting fluctuations across work types.

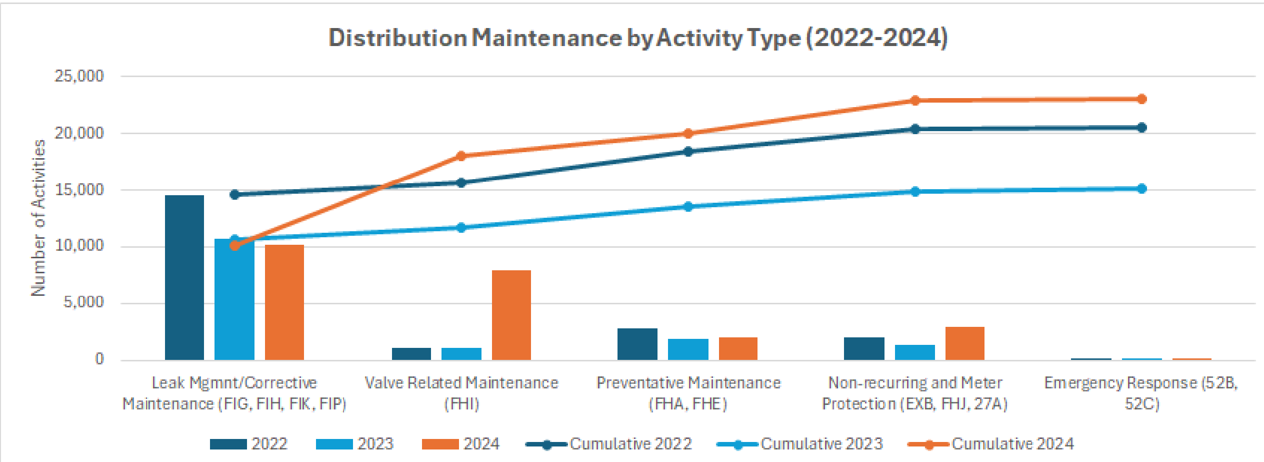

Figure 25: Distribution Maintenance by Activity Type from 2022-2024

Notable patterns include:

- Leak-repair work represents most of the O&M activities and cost.
- A sharp increase in service valve maintenance and replacement during 2024.
- Steady preventive maintenance volumes including scheduled service line replacement.
- Ongoing meter protection and non-recurring project activity.
- Consistent emergency responses to main and service line dig-ins.

Alignment with Asset Management Plan (AMP)

PG&E's Distribution Mains and Services (DMS) AMP (GP-1102 Rev. 11) outlines objectives for leak management, corrosion control, dig-in prevention, and lifecycle planning. PG&E reports that maintenance activity data from 2022–2024 demonstrates alignment with the AMP in several areas:

- Leak Management: Average open Grade 2 leak age was reported at 114 days in 2023, below the PG&E targeted 180-day average leak age.[96] High volumes of leak repairs

[96] In PG&E's Distribution Mains and Services Asset Management Plan, PG&E's objective is to "Maintain an average age of 180 days or less for open Grade 2 leaks"

supported backlog reduction.

- Corrosion Control: Cathodic Protection remediation addressed unprotected steel segments, with 429 CP indicators remediated and 61 miles resolved.
- Dig-in Prevention: PG&E stated that approximately 390 workshops and 7,500 contractor visits were reported in 2023 to support dig-in prevention.
- Pipe Replacement: Replacement of Aldyl-A and pre-1941 steel pipe continue. Annual replacement rates of the pre-1941 pipes remain below the 2030 target to limit system asset age to 100 years.
- Climate Resilience and Electrification: PG&E indicated that replacement strategies are tied to long-term decarbonization and electrification planning.
- Other Programs: Cross bore inspections, curb valve replacements, and SCADA deployment were noted as active, though some experienced funding or staffing limitations.

Overall, PG&E's maintenance activities manage multiple AMP objectives, though the pace of certain programs is reported to be constrained by resources and funding levels.

Risk Management Context

PG&E's DMS asset family faces a variety of risks that could lead to a Loss of Containment on Gas Distribution Mains or Services (LOCDMS)—a top-tier risk identified on the company's Corporate Risk Register. PG&E reports that distribution maintenance efforts support the mitigation of those risks and contribute to the broader enterprise risk management framework for the following threat categories:[97]

- Corrosion: evaluate and build out CP data collection and real-time monitoring, valve replacements, service riser renewals, and CP corrective work management.
- Excavation Damage: beyond reactive emergency responses, support dig-in prevention programs including approximately 390 prevention workshops and nearly 7,500 PG&E field visits to contractor excavation sites in 2023, valve installations to limit size of emergency gas shutdown zones.
- Material, Weld, and Joint Failures: managed with pipe and fitting replacements and leak surveillance, valve maintenance
- Equipment Failure and Incorrect Operation: addressed through asset replacements, operation procedural updates, and field verifications and inspections.
- Natural Forces: mitigate size of emergency gas shutdown zones with valve segmentation, flexible pipe materials, and ground monitoring.

PG&E reported that the 2024 baseline monetized LOCDM risk score was reported at approximately $107 million per year, with this being the monetized representation of enterprise risk.[98] Distribution maintenance activities contribute to reduced leak frequency,

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[97] Gas Distribution Annual Report Instructions F7100.1-1, page 7-8

[98] The $106.7 million is a monetized representation of enterprise risk associated with loss of containment events

containment of gas migration, and improved emergency isolation. PG&E reports that these efforts demonstrate the impact that day-to-day maintenance has on the broader Enterprise and Operational Risk Management (EORM).

Implementation Challenges

PG&E's AMP identified several factors affecting the pace and consistency of maintenance execution:

- System integration and data gaps: SAP/Work Management System (WMS) alignment and GIS inconsistencies created scheduling and traceability challenges.
- Field execution issues: Staffing limitations reduced cross bore inspection scope, while valve recommissioning required new procedural development.
- Program tracking difficulties: Corrective notifications and CP mitigation work showed backlogs and reconciliation delays.

PG&E noted that these challenges do not alter the scope of the program but influence how quickly and consistently objectives are carried out across the distribution system.

FACILITIES INTEGRITY MANAGEMENT PROGRAM

PG&E's Facilities Integrity Management Program (FIMP) supports Compression & Processing (C&P) and Measurement & Control (M&C) asset families. The program provides an overview of these asset categories and their condition, addresses risk scenarios such as overpressure events and containment loss, and describes monitoring and performance metrics applied across FIMP assets. It also details mitigation strategies including targeted rebuilds, automation enhancements, and safety upgrades. PG&E implemented these mitigation strategies within the broader framework of PG&E's EORM and regulatory obligations. The following provides a summary of the ISM's key FIMP related observations. The first part of this discusses the threats and overall context. The second part discusses two incidents related to identified threats to add context.

FIMP Asset Family Overview and Strategic Context

PG&E's FIMP Asset Family encompasses C&P and M&C facilities. C&P assets consist of PG&E-owned compressor stations, gas storage field processing systems, and associated odorization and control systems. M&C assets include transmission and distribution regulator stations, Large Volume Customer (LVC) pressure regulation and metering sites, distribution farm taps, and SCADA-enabled data collection telemetry infrastructure.

PG&E states that FIMP standards and guidelines were developed to define asset management programs, identify, assess, and mitigate asset risks related to equipment condition, safe operation practices, equipment obsolescence, overpressure events, and gas loss of

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on gas distribution mains or services. It includes safety, reliability, and financial consequences, all expressed in risk-adjusted dollar values, as required under the CPUC's revised Risk-Based Decision-Making framework. The score reflects expected annualized risk exposure based on 1) event frequency, 2) severity of consequences, and 3) cost and impact estimates from PG&E's bowtie risk model and consequence-of-risk-event calculations.

containment. FIMP operates within the broader framework of PG&E's AMP and are supported by asset-specific management plan documentation.

The FIMP asset structure also aligns with PG&E's EORM model and incorporates regulatory mandates such as the CPUC's Risk Based Decision Making Framework and the use of Cost-Benefit Analysis (CBA) for risk evaluation and investment justification.

Asset Base and Condition Summary

PG&E's FIMP M&C and C&P assets represent a technically and geographically diverse infrastructure supporting core gas system functions. These assets vary widely in configuration, age of applied technology, and remote operational visibility.

Measurement & Control Assets

M&C facilities include transmission and distribution regulator and meter stations, LVC regulator and metering sites, distribution farm taps, and SCADA-enabled telemetry systems. The condition of these assets varies significantly. Transmission stations range from modern SCADA-integrated facilities to legacy vault-based sites with obsolete actuators and inconsistent control logic (some operating without secondary overpressure protection).

Distribution stations, particularly pilot-operated types, are reported to experience reliability issues such as regulator lock-up and seat wear, and many lack secondary overpressure protection. High Pressure Regulator type stations offer some standardization but are often installed without telemetry or SCADA visibility.

Farm taps frequently reside in underground vaults with corrosion exposure, aging valves, and limited inspection history.

LVC regulator and metering facilities lack standardized design and when supporting intermittent operations, can function as hydraulic dead ends,[99] that may increase overpressure risk.

While efforts such as the Critical Documents Program and integration of Station Feature Lists into GIS improved visibility and standardization, PG&E reports that data integrity challenges persist, especially at older, undocumented sites.

Compression & Processing (C&P) Assets

PG&E currently operates nine compressor stations supporting long-distance transmission, pressure maintenance, and two compressor stations at PG&E-owned gas storage field operations. One of the nine compressor stations was retired due to obsolescence in May of this year. These facilities are aligned to PG&E's backbone transmission system and include associated processing infrastructure such as odorization units and SCADA systems.

Compressor stations vary in age and configuration, with several undergoing modernization or

[99] A hydraulic dead end refers to a section of pipe or line with no downstream flow path. When a pressure regulator is installed without a relief valve on such a line, excess fluid (gas or liquid) cannot be relieved, creating a high risk of localized or catastrophic overpressure.

rebuilds in progress to replace aged equipment, aging electric systems and hybrid shutdowns.

PG&E reported that facility condition issues include degraded control systems, aging fuel gas valves, limited automation, and incomplete SCADA integration. Some stations operate with hybrid control configurations that limit remote diagnostics and increase reliance on manual intervention.

Risk Characterization and Threat Landscape

PG&E applies a risk management framework to assess and mitigate threats across its M&C and C&P asset families. These assessments support the company's EORM model by scenario-based methodologies such as Bowtie Analysis and Cost-Benefit Analysis

Risk profiles for M&C and C&P assets are developed using a combination of asset condition data, event frequency, system criticality, and external hazard exposure. These models are applied at both the individual site level and across asset fleets to inform prioritization of mitigation strategies under the assets FIMP.

Primary Risk Scenarios

Overpressure is a leading risk scenario identified by PG&E for M&C assets and has been highlighted in multiple Gas Safety Plans. Risk threat vectors for overpressure include pressure regulation set-point drift, frozen pilot controllers, failed pressure regulation shutoffs, and manual intervention operation errors. Mitigation strategies include:

- Install secondary overpressure protection
- Upgrade SCADA and PLC equipment and programming
- Rebuild critical capacity stations and station vault replacements

Loss of containment (LOC) is another risk scenario identified by PG&E that applies to both M&C and C&P assets, with focus at compressor station high-pressure equipment and rotating machinery. Contributing factors include:

- Degraded control systems and unsupported legacy machinery components
- Aging fuel gas valves and pressure blowdown actuators
- Inadequate detection of vibration, surges, or fire hazards
- Limited redundancy in safety shutdown systems

PG&E considers mitigation measures for LOC to include facility rebuilds and targeted equipment replacements, upgrades to PLCs, MCCs, and natural gas detection systems, and enhanced emergency shutdown designs and vibration monitoring.

Incident-Driven Risk Indicators

Recent compressor control system related incidents at two separate compressor stations reflect the accuracy of PG&E's prediction of operation outage events discussed in the Gas Safety Plan.[100] At one station, a compressor engine was reportedly operating outside manufacturer specifications, which accelerated wear of engine components, resulting in engine failure and a

[100] 2023 and 2024 Gas Safety Plan.

compressor outage. At another station, the malfunction of an obsolete control system was reported to cause a backfire event, due to incorrect fuel calibration protocol. In both cases, PG&E reported that predictive indicators such as engine load profile warnings and fuel calibration anomalies were present prior to the incident.[101]

Prior to the incidents, PG&E's Gas Safety Plan identified systemic threats that affect both asset families:

- Obsolescence and Vendor Support Gaps: Legacy compressors and early-generation PLCs lack OEM support complicating equipment maintenance. [102]
- Seismic and Geohazard Exposure: Facilities in fault zones or subsidence-prone areas face elevated structural risks. [103]
- SCADA and Telemetry Limitations: Incomplete remote visibility hinders early detection and root cause analysis. [104]
- Data Quality Issues: Inaccurate or outdated GIS data reduces the precision of fleet-level risk modeling.[105]

Across both FIMP asset families, PG&E tracks a range of performance indicators, including:

- Equipment availability and runtime hours
- Unplanned shutdown rates
- Completion of preventive and corrective maintenance
- Regulatory compliance inspections (e.g., valve checks, pressure verifications)
- Station impairments and duration
- SCADA-captured trip and alarm events
- Workorder backlog and overdue corrective actions

These metrics are primarily reviewed at the operational level by site leads, regional supervisors, and engineering support teams. Aggregated data is evaluated during quarterly and annual program meetings.

Compressor stations face persistent performance challenges, particularly at aging facilities. Due to recent incidents at the two compressor stations discussed above, PG&E identified alarm patterns and operating anomalies that were not detected or acted upon before equipment failure. PG&E data shows that trip frequency and maintenance intensity are not currently integrated into PG&E's risk monitoring frameworks.

The ISM observed that performance monitoring of M&C assets is inconsistent due to incomplete SCADA coverage and non-standard station operation configuration. Many legacy ERX-based facilities rely on manual or paper-based inspection documentation as compared to

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[101] 2025 Gas Safety Plan.

[102] Referenced in PG&E's Gas Asset Management Plans.

[103] 2025 Gas Safety Plan, pg. 41 & pg. 59. Additionally referenced in PG&E's Gas Asset Management Plans.

[104] 2025 Gas Safety Plan, pg. 76. Additionally referenced in PG&E's Gas Asset Management Plans.

[105] 2025 Gas Safety Plan, pg. 37-38. Additionally referenced in PG&E's Gas Asset Management Plans.

full RTU-based facilities[106].

GAS CLEARANCE OPERATIONS

In ISM Report 6, an incident at PG&E's Kettleman Compressor Station was detailed, including PG&E's Root Cause Evaluation (RCE) and the resulting Corrective Actions (CAs). As background, the incident occurred on July 10, 2024, during a complex, multi-day, multi-phase gas clearance operation[107] tied to a valve replacement project. This operation involved both depressurization and purging of the system to enable construction activities.

During purging of the system in its out-of-service state to restore service, deviations from the approved clearance plan took place. These included the unauthorized removal of a blind flange and the valve selection for fine control within the station. Not recognizing the abnormal operating condition (AOC) when the hydraulic operator failed led to an uncontrolled release of gas, resulting in a combustible plume at ground level of the worksite, which subsequently ignited causing serious injuries to one worker and minor injuries to others.

The ISM held numerous discussions with PG&E, reviewed gas clearance processes, observed a gas clearance operation in the field, and monitored the status of CAs prescribed following the Kettleman RCE.

Gas Clearance Process

PG&E's Gas Clearance Process is guided by a series of procedures that covers planning, writing, endorsement, approval, execution, revision, and recordkeeping for gas clearance work. The process is collaborative, involving the Project Owner, Clearance Writer, Engineering, and other stakeholders.

- Initiation & Planning**:** The Project Owner identifies the need for a clearance and works with the Project team, specifically the project engineer, to define the job scope, assess system impacts, and complete pre-clearance activities. The Clearance Writer drafts the Work Clearance Document (WCD), which details the project scope, sequence of operations, safety requirements, and other critical information given to the Clearance Writer through a series of clearance planning meetings put together by the project manager.
- Endorsement & Approval**:** The WCD is routed electronically for endorsement by all required stakeholders (e.g., Engineering, Facility/Station Engineer, Project Engineer). Once fully endorsed, Gas Control reviews and approves the clearance.

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106 Many older M&C stations were equipped with ERX controllers (limited automation, requiring manual record-keeping and inspections) whereas full RTU-based facilities are fully integrated into SCADA, with digital monitoring and remote visibility.

107 Gas clearance is a formalized process governed by PG&E's utility standard TD-4441S, which outlines the requirements for safely isolating and purging natural gas from transmission or distribution pipeline segments. This process enables safe execution of project work, maintenance, or operational changes by eliminating hazardous energy sources and ensuring system integrity.

- Execution: Field personnel use a printed WCD during the work. The clearance supervisor conducts safety verification and obtains final authorization from Gas Control before starting work.
- Revisions: Any changes to the clearance during execution, especially those affecting system configuration, isolation points, or flow, must be communicated to Gas Control to determine if minor or major revisions are needed in the WCD. After determination is made then the WCD gets updated and is reviewed and approved by Gas Control.
- Recordkeeping: All clearance documents, endorsements, revisions, and safety checklists are retained as part of the project record.

This process is designed to ensure safe, controlled, and well-documented gas operations, with clear roles, responsibilities, and approval steps at every stage.

Site Visit Summary and Discussion

The ISM observed Phase 2 of an In-Line Inspection (ILI) Upgrade Project on a 10-mile section of a PG&E natural gas pipeline. The purpose of this visit was to observe PG&E's gas clearance procedures in the field, specifically focusing on several key steps of the gas clearance process:

- Completion of natural gas purging: pipeline removal from service, depressurization, and venting.
- Lockout/Tagout[108] (LOTO) confirmation and "Report On": system de-energized verification and isolation; status communicated to gas control.
- Clearance work: clearance work execution and construction/maintenance team coordination.
- Removal of LOTO and "Report on Test": reestablishment of site control, confirmation of system isolation, removal of LOTO, and communication of status and readiness to gas control.
- Initial purge and gas reintroduction: replacement/purging of air with low-pressure natural gas to return pipeline to service.

The two-day site visit began with the ISM observing the completion of natural gas purging and verification, followed by a project briefing, where PG&E's clearance supervisor discussed the scope of work and the day's workplan. The ISM then visited the clearance work locations (meter station and a valve station), and a natural gas purging location.

The second day began with a PG&E tailboard meeting that included gas clearance workers, construction workers, safety, supervision, and support staff, where the work plan for the day was discussed, and the roles and responsibilities of both the clearance and construction teams were reviewed. The pipeline was then re-confirmed to have no natural gas present using gas measurement devices and LOTO was re-confirmed. The team then contacted gas control to "Report On". An example of a caution tag on a valve can be seen in Figure 26.

[108] LOTO is a critical procedure used to ensure equipment remains de-energized and safe by isolating equipment from energy sources using a physical "lock and tag" unique to the employee performing the work.

After the "Report On," the clearance team passed project control to the construction team, who completed the project work. Pictures of some of the work completed, including replacement of two pipe tees and installation of a pig launcher can be seen in Figure 26.

Figure 26: Representative Clearance Field Observations (Caution Tag (left), Replacement of Two Pipe Tees (middle), and Installation of a Pig Launcher (right))

Towards the end of the second day, after the construction work was complete, the construction team transitioned project control back to the gas clearance team. The clearance supervisor confirmed the state of the system and removed LOTO. Authorization was then received from the Gas Control Center to restore the system, as "Report on Test". The clearance supervisor established an exclusion zone (an area around a gas purging operation where people are not permitted for safety) with ISM and PG&E staff repositioning approximately 20 feet from the vent stack where air and natural gas would be purged. The clearance supervisor authorized the reintroduction of natural gas, starting at very low pressures (one psi and increasing to two psi once confirmed). The full restoration of the 10-mile pipe segment was estimated to take approximately two hours.

The ISM made several key observations during the site visit regarding the gas clearance operations in accordance with PG&E's gas clearance procedures: Job Site Safety Analyses (JSSA's) were performed each day when the ISM entered each site, a vertical vent stack was installed for natural gas purging operations, an exclusion zone was established during natural gas purging operations, and the clearance supervisor and the Gas Control Center communicated during key steps of the procedure.

Status of Corrective Actions from Kettleman RCE

The Kettleman RCE contained several findings related to PG&E's gas clearance operations and prescribed several CAs or specific actions to be taken to address the root causes and contributing causes of the event. The information was detailed in ISM Report 6, and the following provides a brief update on the status of each Root CA and key Contributing CAs, as provided by PG&E:

Root Cause (RC)	CAPR	Status / Update
RC CAPR1	Develop Safety & Culture Achievement Plan	Assigned to Gas Engineering (Oct 2024); deliverables under development; completion early 2026; final plan by Sept 2030.
RC CAPR2	Establish Exclusion Zones	Extended (Dec 2025); exclusion zone definition and radius table developed; incorporated into draft procedures; extension allows for procedure updates.
RC CAPR3	Install & Stage Vent Stacks	Extended (Mar 2026); blowdown stack design near final; funding and vendor selection underway; permanent station mods to follow TD-4136P-01 during project execution. Extension allows for material purchase, construction, and delivery.
RC CAPR4	Implement Risk Identification & Readiness Reviews	Closed (Aug 2025); Implemented weekly risk reviews, Break-in Approval Process, and readiness accountability; roles confirmed across Gas Transmission, Clearance Ops, and GPOM.
Contributing Cause (CC)	**CA or CAPR #**	**Status / Update**
CC1 CA1	Develop Configuration Control Devices	Closed (Jul 2025); ECCDs not recommended—no safety benefit, potential inefficiencies; focus shifted to procedural adherence, training, and LOTO/MOC compliance.
CC1 CA2	Evaluate Clearance Supervisor Roles and Responsibilities	Extended (Oct 2025); leadership email drafted and reviewed; incorporating GPOM feedback; delivery planned via all-hands call; jurisdictional matrix updates in progress.
CC1 CA3	Implement Clearance and Tagging Event Monitoring	Extended (Oct 2025); event monitoring protocol in final review; CRT agenda being updated; weekly CAP extracts in place; SAP dataset and dashboard in development. Extension supports process finalization and delivery.
CC2 CA1	Implement Training for Clearance Operations and Purging	Extended (Dec 2026); CS2 advanced training for ~300+ supervisors launching Q1 2026; rollout over several months; extension allows time for content development and delivery.
CC2 CA2	Develop A-38 Job Aid	In progress (Due Dec 2025); Procedure has been drafted, waiting for final review and approval.
CC3 CA1	Implement Trending and Performance Monitoring	Closed (Mar 2025); gas cross-functional program launched to trend serious safety risks via human performance classification; trends shared with Gas Leadership for action planning.
CC3 CA2	Establish Quality Improvement for High-Risk Programs	Extended (Oct 2025); quality improvement plan (QIP) framework drafted, pending senior leadership review; extension allows time to identify high-risk work, complete self-assessments, and develop improvement plans

CUSTOMER FACILITY MAOP VALIDATION INITIATIVE

In 2018, as part of PG&E's station-specific Maximum Allowable Operating Pressure (MAOP) Validation initiative, commonly referred to as the Station Feature List effort, PG&E validated MAOPs of approximately 400 LVCs. During this process, new MAOP values were assigned to customer facility connections that previously lacked recorded limits, primarily because most were categorized as a "farm tap" facility. In some cases, the assigned new MAOP limits did not accurately reflect PG&E's facility design guidelines, operating practices, or original construction standards. These unique facility design, operation, and construction variances contributed to unintended overpressure (OP) events where pressure exceeded the new assigned MAOP limits by 10 percent or more. As a result, FIMP initiated a management of change review of 328 LVC facility outlet MAOPs resulting in adjustment of 219 LVC MAOPs, while 109 LVC facility outlet MAOP's remained unchanged. This review began in 2021 and was completed in 2023.

Transmission Definition Adjusted LVC Facility Count

In June of 2025, PG&E implemented the new Transmission Definition (TransDef), which reclassified select lower-strength transmission pipelines as distribution pipelines. Under TransDef criteria, about 400 customer "farm taps" were redefined as either LVCs or Medium Volume Customers (MVCs). As of 2024, PG&E recognized 108 LVCs (facilities rated at 10 million cubic feet per day or more) and 274 MVCs (facilities rated above 40 thousand cubic feet per hour but below 10 million cubic feet per day), for a total of 382 facilities connected to the system.

Customer Facility Gas Operation Overpressure Event Review

In 2025, PG&E began a review of OP events primarily resulting from abrupt interruptions in customer facility gas operations. Future adjustments to customer facility outlet MAOP's is under evaluation.

FIMP is also reviewing bypass pressure regulation equipment at LVC gas facilities for risks of over pressurization. PG&E provided the ISM with an example of an OP event that occurred when an LVC facility abruptly shut down gas flow. At the time, PG&E routed gas through a temporary single-line bypass during onsite maintenance. When the customer shut down gas flow, the bypass regulators did not immediately control the pressure surge from the transmission supply of 710 psig, which briefly exceeded the customer's facility MAOP of 400 psig by 13% (452 psig) before gas was released through a pressure relief valve. Onsite PG&E maintenance personnel immediately shut off the facility gas supply, purged pressure, and inspected the bypass regulation equipment.

From 2022 through mid-2025, PG&E reported the following OP events at LVC and MVC facilities described in Table 17. Large OP events are defined as pressures at least 10% above the assigned MAOP or pipe hoop stress above 75% of yield strength or SMYS:

Table 17: LVC and MVC OP Events from 2022 to 2025 YTD

Event Year	Large OP Event	Small OP Event
2022	2	3
2023	2	3
2024	2	8
2025 YTD	3	1

PG&E reported several possible customer facility OP mitigation measures to the ISM, including:

- Desktop reviews of customer gas facility equipment to identify possible failure modes
- Equipment modifications or automatic shut-off "slam shut" valve installations
- Installation of gas pressure relief valves
- Inform customers on how their operations impact gas supply regulator equipment

In addition to customer facility connections, PG&E recorded OP events at distribution and transmission stations where regulators and monitors failed in the "open" position.[109] As of July 2025, PG&E mitigated this common failure mode at 1,008 of 1,431 distribution stations (about 70%) and 132 of 498 transmission stations (about 26.5%). Reported OP events at these distribution and transmission stations were as follows:

Table 18: Facility OP Events from 2022 to 2025 YTD

Event Year	Large OP Event	Small OP Event
2022	9	18
2023	5	12
2024	4	16
2025 YTD	5	4

PG&E's mitigation effort at these facilities includes installing dual bypass pressure regulation runs with automatic gas shut-off valves and remote monitoring (SCADA) in new facility installations, adjusting regulation pressure set-points, reducing supply line pressures where possible, identifying elevated OP risks at low-customer-count sites, and improving gas debris management to reduce pressure regulation equipment malfunctions.

DAMAGE PREVENTION PROGRAM

PG&E implements a Damage Prevention Program to reduce excavation-related threats to gas transmission and distribution infrastructure. The program is comprised of operational controls, public outreach, and risk-informed decision-making, and integrates with PG&E's Transmission Integrity Management Plan (TIMP) and Distribution Integrity Management Plan (DIMP). Several PG&E groups support the program with roles that range from governance, to field execution, and continuous improvement. These groups include:

- Dig-in Reduction Team (DiRT): Conducts root cause analyses of excavation damage incidents and informs contractor outreach and corrective actions.
- Damage Prevention Team: Manages ticket workflows, location activities, coordinates with 811 centers, and supports data integration for risk modeling.
- Standby Governance Team: Oversees deployment of field inspectors for high-risk excavations and enforces field meet protocols.
- GIS and Risk Model Committees: Supports the development and calibration of the Risk models, ensuring alignment with PG&E's transmission and distribution integrity management programs.

Data provided by PG&E shows that excavation damage remains one of the gas utility's highest-consequence, time-independent threats (as seen in PHMSA rates discussed earlier). Accordingly, PG&E states that the Damage Prevention Program is prioritized within PG&E's asset management strategy, with Risk model outputs directly informing patrol frequency, mitigation planning, and CAP development.

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[109] An open position is when the downstream devices are impacted by full pressure across the failed device.

Excavation Damage Prevention and Outreach Update

PG&E's excavation damage prevention operations are based on standardized procedures for managing excavation notifications, field inspections, and public outreach. PG&E reported that these operations are designed to reduce third-party damage risk through public outreach and education, improving locate accuracy and monitoring excavation activity around pipeline assets. PG&E receives over one million 811 locate requests annually.[110]

Field marking and inspection protocols are risk-tiered, with mandatory standbys and "field meets" required for high-risk excavations. PG&E deploys inspectors based on ticket characteristics, proximity to critical infrastructure, and historical incident data. Marking accuracy and visibility performed by PG&E's inspectors in response to 811 calls are monitored by the Damage Prevention Team for quality control and timeliness.

PG&E report that discrepancies between system-of-record data and actual field conditions of pipelines remain a challenge including mismatches in cover depth of pipelines and locate mark maintenance. As an example, in a 2023 dig-in incident the facility was physically located and marked using PG&E's established tools and procedures. However, the system-of-record cover depth indicated a depth of 59 inches. The subsequent field measurements after the dig-in incident identified an actual cover depth of 15 inches. This discrepancy originally resulted in the segment being classified in a lower risk percentile so it was not prioritized by PG&E for risk mitigation despite its prior dig-in history. PG&E reported advancements in its Reduced Cover Inbox Program, consolidating data on shallow or exposed pipeline segments. These refinements are designed to improve the accuracy of the Risk model by incorporating direct field measurement methods and prioritizing segments with incomplete or outdated cover depth data.

PG&E's public awareness outreach campaigns reached nearly 35 million impressions[111] in 2024, with increases in media engagement and community presentations. The most notable increases occurred in social media between 2022 to 2023, which rose by 55% year-over-year, and traditional media, which rose by 150% year-over-year from 2023 to 2024. PG&E's Risk model currently assigns a 2–10% risk reduction weight to these factors.

Table 19: PG&E's Public Awareness Outreach Campaign Impressions

Activity Type	2022	2023	2024
Direct Mail, Bill Inserts, eCampaign	20.62	21.56	19.71
Online / Social Media	8.58	13.30	13.45
Events / Presentations / Community Events	0.57	0.77	0.71
Traditional Media (TV / Radio)	0.44	0.40	1.00
Total	**30.21**	**36.03**	**34.86**

[110] Starting in 2022, PG&E implemented ticket filtering enhancements to exclude out-of-state requests and overly broad locate tickets, such as those covering areas greater than two square miles.

[111] Impressions refers to marketing and communications instances where a person was exposed to public outreach material, for example, seeing an ad, a social media post, a webpage banner, a mailed notice, or other campaign content.

Dig-in incidents remained relatively stable across the reporting period, with 1,276 reported in 2024. One Call[112] compliance rates plateaued, with "No Notification" incidents continuing to account for a significant portion of damages. However, repeat offender decreased by over 40% from 2023 to 2024, indicating more coordination and compliance.

Table 20: Dig-In Incidents by Excavation Damage

Excavation Damage	2022	2023	2024
One-Call Notification Practices Not Sufficient	689	687	675
Locating Practices Not Sufficient	145	111	119
Excavation Practices Not Sufficient	623	459	471
Other	18	9	11
Total	**1475**	**1266**	**1276**

PG&E stated it is refining data systems and operational protocols to improve risk visibility and reduce damage frequency, acknowledging ongoing challenges with data accuracy and sustaining high compliance with One Call requirements.

Risk Model Insights

PG&E's Risk models (DIMP and TIMP) serve as the primary tool for prioritizing excavation-related risks. The model incorporates spatial and operational data, including land use, cover depth, One Call activity, dent/gouge history, dig-in frequency, and outreach activity.

During the current ISM reporting period, PG&E reported stability in Risk percentile distribution, with most pipeline segments concentrated in the median risk category. PG&E's calculated LoF of 0.24 ruptures/year for third-party damage in 2024 reflects a decline from 0.27 in 2023 and is below PG&E's historical average LOF of 0.36 ruptures/year. PG&E attributed this reduction to improved One Call ticket filtering and data accuracy.

Cover depth remains a critical input, though data gaps persist due to reliance on legacy survey records as mentioned in the field observations above. PG&E is addressing this through its Reduced Cover Inbox Program, which prioritizes direct measurement methods and data integration.

Additional initiatives that PG&E expects will inform future LoF model refinements include:

- Incorporate dent and gouge data from ILI records.
- Expand public awareness through targeted outreach strategies in high-risk areas.
- Integrate crossbore risk into excavation threat modeling.
- Use Area of Continual Evaluation (ACE) tickets in agricultural zones.
- Refine treatment of dig-ins with unknown party attribution.

The Risk models (DIMP and TIMP) inform capital and O&M planning, patrol frequency, and prioritization of Preventive and Mitigative measures. For example, high-risk segments

[112] 'One Call' refers to the national 811 service, which provides a centralized system for excavators and the public to notify utilities of planned digging activities to help prevent damage to underground facilities.

identified through Risk model outputs have triggered targeted actions such as pressure reductions, aerial patrols, and CAPs. PG&E's reported continued efforts to integrate technology and data-driven tools into damage prevention. A development during the current ISM reporting period was the rollout of the GIS-based Damage Prevention Portal, which provides visibility into high-risk segments, tracks mitigation efforts, and supports decision-making through interactive dashboards.

LEAK SURVEY AND LEAK MANAGEMENT

PG&E's natural gas distribution system is comprised of over 45,000 miles of mains and 3.7 million service lines. Regular leak surveys are required by federal and state best practice: annually in business districts and at least once every three years in other areas. The purpose of these surveys is to identify and repair leaks that affect public safety, reliability, and the environment.

PG&E uses both conventional leak detection tools and advanced methods such as Picarro's Advanced Mobile Leak Detection (AMLD) system. From 2022–2024, more than 1.3 million service lines and 13,000+ miles of mains were surveyed by PG&E each year.

Distribution System Survey Results

PG&E provided the ISM with leak survey data that showed the coverage of the system along with progress made to address inspection and survey backlog due to access issues. The following Table 21 summarizes PG&E's survey activity from 2022–2024, including total distribution main pipeline miles and number of service lines. As depicted in the table, cumulative 2022 to 2024 distribution main leak surveys equal 86% of total 2024 main mileage, and cumulative service line surveys for the same period are more than equal to the total 2024 service line assets.

Table 21: PG&E's Distribution Survey Activity from 2022 to 2024

Distribution Assets	2022	2023	2024
Distribution Mains (miles)	43,700	44,000	45,200
Distribution Mains Surveyed (miles)	13,000+	13,000+	13,000+
Service Lines (million)	3.6	3.6	3.7
Service Lines Surveyed (million)	1.3+	1.4+	1.3+

PG&E reported progress reducing inspection and survey backlogs associated with access. "Atmospheric Corrosion Can't-Get-In inspections" (AC CGIs) dropped from 1,180 to 393 from 2023 to 2024, and Leak Survey CGIs (LS CGIs) decreased from 1,963 to 933 over the same period. This reflects an estimated 69% and 27% reduction in delayed AC and LS inspections, respectively.

Since 2022, Total Annual Costs for Leak Survey has decreased by approximately 20%, while total Leak Survey Annual Units have increased by approximately 15%. This reflects an increase in Leak Survey Services (421,715 units in 2022 to 1,364,697 units in 2024) during the same time period. PG&E reported that the elimination of Picarro AMLD Leak Survey services reflects a shift toward optimizing cost-effectiveness and alternative leak detection strategies.

Leak Management and Repair Performance

PG&E tracks and reports on system leaks. As background, PG&E classifies leaks into three categories:

- Grade 1: hazardous, requiring immediate repair (typically within 24 hours)
- Grade 2: non-hazardous but requiring repair above ground transmission leaks and all distribution leaks no later than 15 months and 12 months for below ground transmission.
- Grade 3: non-hazardous, monitored until repair or replacement is scheduled

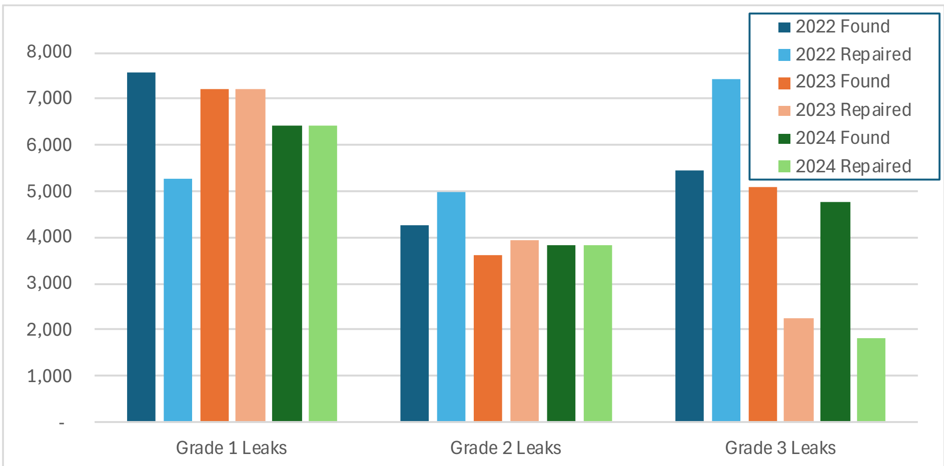

Figure 27: Number of Leaks Found and Repaired by Grade in 2023 and 2024

Figure 27 shows the number of leaks discovered and repaired, by grade, for 2022 to 2024.

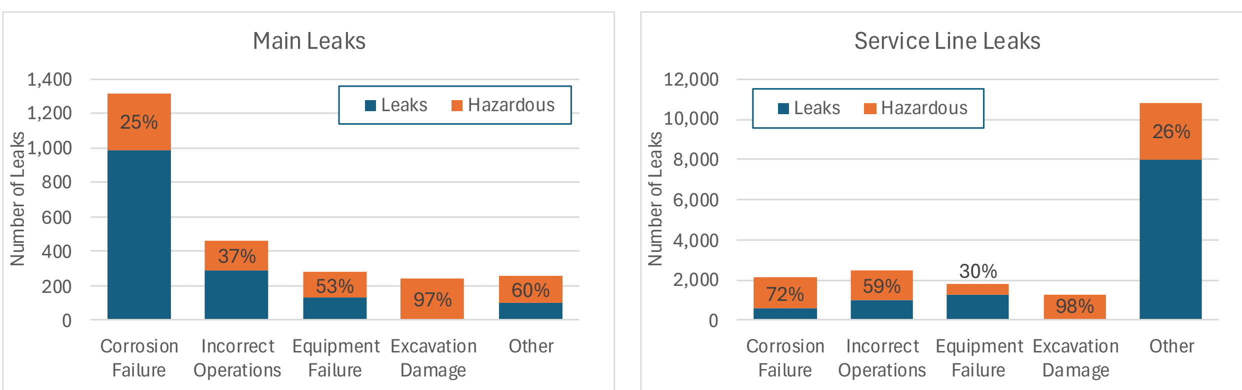

Figure 28: Distribution Main and Service Line Leaks by Cause[113]

PG&E provided the ISM with leak cause data for 2022 as a representative example. Figure 28 details the causes of leaks in 2022 for both distribution mains and services, showing total leaks,

[113] Hazardous is defined as Grade 1 Leaks. Other causes of leaks include pipe, weld, or joint failure, natural force damage, and other forces damage.

hazardous percentages,[114] and leak rates normalized by mileage or number of services. This provides context for understanding recurring failure modes and risk drivers.

The Figure 28 shows excavation damage as the highest hazard rate, with approximately 97% of excavation-related leaks classified as hazardous. Corrosion and incorrect operations remain leading contributors to leak volume, while equipment failures and material issues also play a significant role. Service lines show a high share of leaks from "other", suggesting gaps in legacy classifications.

Table 22 presents the number of open leaks by grade, location (above- and below-ground), and system type (distribution or transmission) for 2023 and 2024. It also summarizes data regarding the timeliness of repairs for Grade 2 leaks against the 180-day target.

Table 22: Number of Open Leaks for Transmission and Distribution for 2023 and 2024

End of Year Open Leak Inventory	2023	2024	2023	2024
	Above Ground		Below Ground	
Open Transmission Leaks	73	79	530	562
Open Distribution Leaks- Grade 3	747	657	8,950	9,271
Open Distribution Leaks- Grade 2	248	271	1,493	1,396
Average Days to Repair Grade 2	113	131	113	131
Number of Grade 2 Leaks > 180 Days	747	657	747	657

At the end of 2024, PG&E reported nearly 10,000 open Grade 3 leaks on distribution facilities, the majority below ground. Grade 2 leaks declined slightly (-4.2%) overall, but the number that was open longer than 180 days rose from 180 in 2023 to 304 in 2024, reflecting longer repair times. Grade 1 leaks continued to be addressed within 24 hours, with a 98.7% resolution rate for repairs within 24 hours.

Reported data from PG&E indicates that leaks continue to arise from excavation damage, corrosion, operations, and material issues, with most Grade 1 leaks repaired within 24 hours and lower-grade leaks remaining open in varying volumes.

Integration with Asset Management Plans

PG&E stated that leak survey and repair data is incorporated into distribution and transmission AMPs. Within these plans, leak history and repair performance inform the Leak Management and Corrective Maintenance Programs, the Plastic Pipe Replacement Program (targeting Aldyl-A and early-generation plastics), the Gas Pipeline Replacement Program (focused on cast iron and pre-1941 steel), and corrosion control enhancements that link CP upgrades with leak repair activity. PG&E stated that leak data also serve as inputs to the DIMP and TIMP to guide capital planning and prioritization of pipeline segments.

PG&E participates in American Gas Association benchmarking to evaluate performance against peer utilities on measures such as leaks per mile, excavation damage, and repair timeliness. The company also employs technological tools including digital job packets, workflow management systems, and cost-tracking by survey unit or repair. While AMLD surveys were

[114] Hazardous is defined as Grade 1 Leaks.

once a primary approach, PG&E stated that it adjusted deployment to balance cost-effectiveness with alternative detection methods.

PG&E performs internal audits to examine leak classification practices, survey effectiveness, backlog prioritization, and coordination among teams responsible for leak repair, corrosion control, and capital replacement. PG&E reported that findings from these reviews have led to AMP adjustments to better target risks linked to equipment, operations, and materials.

FIRST-TIME ILI PROJECTS / DIRECT EXAMINATIONS

Between 2022 and 2024, PG&E conducted a series of first-time pipeline in-line inspection (ILI) projects in addition to its regular multi-year TIMP compliance pipe inspections. These ILI projects provided inspection data for pipe routes that had not previously been assessed with ILI tools. These ILI projects provide initial indirect external pipe condition data to supplement engineering estimates and other indirect pipe conditions surveys such as CP testing and compliance pipe exposure digs.

First-Time ILI Projects (2022–2024)

PG&E indicated that many first-time ILI projects were only possible after modifications to the pipeline to allow ILI tools to travel through the pipe without obstruction, which the ISM discussed in detail in ISM Previous Reports. Example pipe route physical modifications include:

- Replacing short-radius pipe bends with long-radius bends
- Replacing small-diameter valve openings with larger openings
- Installing pressurized ILI launchers and receivers

During the 2022-2024 timeframe, two types of ILI projects were undertaken:

- Traditional ILIs: -An internal inspection of thousands of feet of pipeline recording detailed pipe condition by advanced in-line tools while propelled through the pipeline by existing gas flow as the pipeline remains in service.
- Non-Traditional ILIs: Shorter-distance inspections of a few hundred feet to less than one mile employ robotic self-propelled, tethered, or water propelled ILI tools performed while a pipeline is out-of-service. In some cases, these robotic tools were inserted into the pipe by cutting and removing a section of pipe; in others, robotic tools were deployed through existing tool launchers.

First-time ILI project data replaces or supplements prior engineering pipe condition estimates with actual internal and external pipe condition data. Prior to ILI projects, PG&E reported that engineering assessments of pipe condition were based on indirect methods such as CP testing, and leak surveys, supplemented by direct examinations to expose pipe at engineering selected pipe locations. First-time ILI projects add direct internal and external pipe condition data to replace or refine those estimates.

Table 23 shows the number of routes inspected, average installation year, pipe size, and average run length for both traditional and non-traditional ILIs. Across both types, PG&E performed an average of 30 ILI projects annually during the three-year period.

Table 23: Traditional and Non-Traditional First Time ILI from 2022 to 2024

1st Time ILI Year	Pipe Routes	Avg Pipe Install Yr	Avg Pipe OD Inches	Avg ILI Run Feet
Traditional ILI				
2022	7	1972	19	134,000
2023	9	1962	19	99,000
2024	11	1965	13	49,000
Non- Traditional ILI				
2022	9	1986	14	2,600
2023	8	1984	14	1,900
2024	15	1975	14	2,300

Direct Examination Digs, ILI Anomaly Verification & Repairs

PG&E indicated that metal loss anomalies identified by first-time ILIs often require direct examination digs to confirm the data and evaluate the anomalies for possible repair:

- Direct Examination Digs: Exposing pipe, removing coatings, cleaning surfaces, and applying ultrasonic or magnetic measurement tools.
- ILI Anomaly Verification: Comparing ILI anomaly indications with field conditions observed at excavation sites.

External ILI metal anomaly repairs may be as insignificant as grinding external pipe surface to flatten pipe weld aberrations, or as significant as cutting-out and replacing a pipe segment to eliminate single or clusters of metal loss due to external or internal corrosion.

PG&E performed direct examination pipe exposure digs after ILI data collection to directly inspect pipe condition data and confirm ILI identified metal anomalies. PG&E reports that direct examination data allows for measurement of pipe wall conditions and comparison with ILI data including metal loss anomalies such as external corrosion, internal corrosion, and weld-related irregularities. Once ILI data is collected, excavation (digs) to expose pipe are assigned to each significant ILI metal anomaly to verify ILI data and perform pipe repairs if required. These digs may be classified as either:

- Immediate: Requiring near-term excavation. In some cases, PG&E indicated that pipelines operating at higher pressures were operated at reduced pressure to ensure pipeline operation safety until metal anomalies are inspected and pipe repairs were made.
- Non-Immediate: Delayed excavation on lower risk ILI metal anomalies for pipe inspection and possible repair.

Table 24 summarizes the number of first-time ILI routes requiring metal anomaly indication direct examination digs and their assigned priority classifications (immediate and non-immediate) for the years 2022 through 2024.

Table 24: Traditional and Non-Traditional Immediate and Non-Immediate Anomaly Digs from 2022 to 2024

1st Time ILI Yr	Pipe Route	Routes Require Digs	Immediate Dig IDs	Non-Immediate Dig IDs
Traditional ILI				
2022	7	4	2	24
2023	9	8	30	39
2024	11	7	13	21
Non- Traditional ILI				
2022	9	0	0	0
2023	8	3	2	0
2024	15	2	2	2

PG&E excavations often include repairs, ranging from surface weld grinding to pipe segment cut-out and replacement. In some cases, multiple anomaly locations (Dig IDs) can be mitigated within the scope of a single pipe excavation when multiple anomalies are located in close proximity. PG&E provided an example where 17 Dig IDs were mitigated with three pipe cut-outs and replacements.

PG&E reported that it employed the following repair methods during the 2022-2024 timeframe:

- Grinding external pipe to remove minor surface irregularities
- Installing external composite wraps across external corrosion
- Installing welded steel sleeves across more severe metal anomalies
- Cutting out and replacing pipe segments across severe metal anomalies

Pipe Integrity Mitigation Without ILI Assessment

While PG&E reported ILIs as its preferred pipe integrity assessment method, not all pipe routes are ILI piggable. Possible ILI pigging barriers include adverse pipe route operating pressures or gas flow rates, pipe diameter changes, unpiggable pipe route bends, small internal valves openings, internal obstructions, and lack of pig launchers and receivers. PG&E's pipe integrity management program historically relied upon hydrostatic pressure testing, direct assessment, and direct examination digs to identify pipe segments requiring repair or replacement. PG&E surveils gas transmission assets through pipe route patrols, leak surveys, CP testing, geohazard monitoring, consequential pipe class location reviews, and engineering pipe threat and risk assessment.

Line 118B provides an example of pipe integrity mitigation prior to an available first-time ILI performed in 2023. Originally constructed in 1953 with extensions through 1963, Line 118B underwent 36 pipe segment replacements between 1970 and 2020. These replacements occurred for reasons including:

- Regulator station rebuilds
- Pipe leak and damage repairs
- Pipe route capacity expansion projects
- Pipe route relocations to accommodate highway construction
- Pipe modifications for future ILI accessibility

- Observed pipe conditions during various pipe excavations

Figure 29 is an ISM plot of PG&E 2023 TIMP Risk Snapshot pipe segment install dates plotted along 2023 first-time ILI cumulative survey footage that shows the pipe segment replacement history for the 36 pipe segment installations prior performing the first time L-118B ILI project.

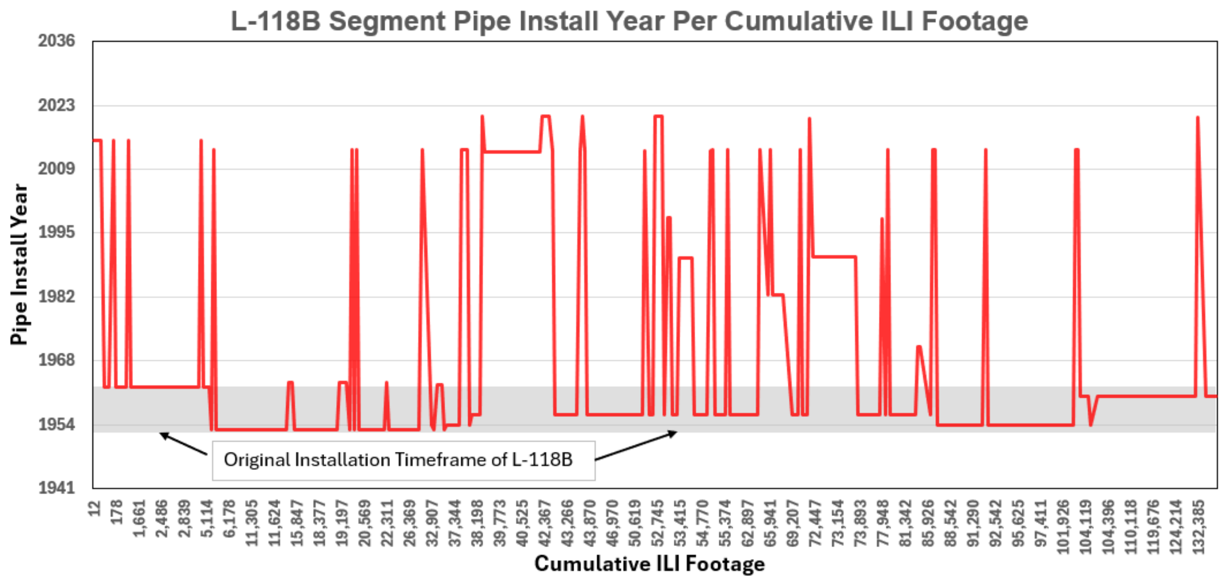

Figure 29: Segment Pipe Install Year Per Cumulative ILI Footage

CORROSION CONTROL MAINTENANCE

During the current ISM reporting period, the ISM reviewed PG&E's corrosion control and maintenance activities across its gas transmission and distribution systems. Corrosion control is a component of PG&E's asset integrity strategy, designed to mitigate time-dependent threats to buried and exposed metallic infrastructure. These efforts are governed by federal regulations, internal safety policies, and PG&E's Transmission and Distribution AMPs.

PG&E's corrosion control program covers 6,394 miles of transmission pipeline and roughly 42,000 miles of distribution main, supported by impressed current cathodic protection[115] (ICCP), galvanic systems, coatings, and atmospheric inspections. According to PG&E, ICCP protects 6,308 miles of transmission and 18,346 miles of distribution main pipeline, while galvanic systems cover nearly 1,100 combined miles. The program includes more than 4,870 rectifiers, all with remote monitoring capabilities, and over 200,000 Electrical Test Stations (ETS). In 2023, PG&E reported 93% CP availability, with 79.7% of ETS readings meeting performance criteria.

PG&E has 114 miles of coated-only mains and 4,044 unprotected services that are not protected by CP. PG&E stated that these risks are being addressed through Unprotected Steel Survey and Enhanced Cathodic Protection Survey programs, which identify legacy steel

[115] Impressed current cathodic protection is the most widely used system (installed consistently since 1960) with an expected lifespan of approximately 30 years.

segments, validate protection levels, and update GIS records if needed. Long-term objectives include achieving full Close Interval Survey[116] (CIS) coverage on the transmission system by 2034 and eliminating unprotected steel mains and services from the distribution system by 2026.

As of the current ISM reporting period, PG&E managed 4,754 open corrosion-related work orders, including rectifier repairs, low ETS readings.[117] Some tasks remain unresolved for extended periods due to access limitations, discrepancies, vendor coordination, and workforce constraints. In 2024, PG&E completed 2,701 corrosion-related leak repairs and reported ongoing efforts to improve planning, automate follow-ups, and reduce aged backlog.

[116] CIS assesses the effectiveness of cathodic protection systems using closely spaced voltage measurements between the pipeline and the surrounding soil.

[117] A low ETS reading indicates that the cathodic protection system is failing to provide adequate corrosion protection for the pipeline at that location.