

FILSINGER ENERGY
P A R T N E R S

PG&E
INDEPENDENT SAFETY MONITOR STATUS UPDATE
REPORT

May 26, 2026



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LIST OF TERMS AND ACRONYMS

Term/ Acronym	Meaning
AC	Alternating Current
ACC	Accumulated Critical Current
AFA	Asset Failure Analysis
AFO	Asset Family Owners
AGA	American Gas Association
AI	Artificial Intelligence
AMI	Advanced Meter Infrastructure
AMP	Asset Management Plan
AMR	Annual Maintenance Review
ANSI	American National Standard Institute
AOC	Areas of Concern
ATS	Applied Technology Services
BCF	Billion Cubic Feet
BCMA	Board Certified Master Arborist
BDP	Business Deployment Process
BLM	Bureau of Land Management
BMP	Best Management Practices
BPD	Business Plan Deployment
CA	Corrective Action
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CAL FIRE	California Department of Forestry and Fire Protection
CAP	Corrective Action Plan
CBM	Condition Based Maintenance
CEM	Capital Emergency Material
CEO	Chief Executive Officer
CESO	Customers Experiencing Sustained Outage
CEQA	California Environmental Quality Act
CGA	Common Ground Alliance
CIRT	Centralized Inspection Review Team
CM	Continuous Monitoring
CMD	Circuit Mile Days
CMMS	Computerized Maintenance Management System
COE	Critical Operating Equipment
COO	Chief Operations Officer
CP AMP	Compression and Processing Asset Management Plan
CPI	Comprehensive Pole Inspection
CPCN	Certificate of Public Convenience and Necessity



Term/ Acronym	Meaning
CPUC	California Public Utilities Commission
CPZ	Circuit Protection Zones
CRO	Chief Risk Office
CV	Computer Vision
DC	Direct Current
DCD	Downed Conductor Detection
DFA	Distribution Fault Anticipation
DIMP	Distribution Integrity Management Program
DiRT	Dig-in Reduction Team
DSBSN	Distribution Substation
EC-Tag	Electric Corrective Tag
ECCD	Enhanced Configuration Control Device
EDAPT	Electric Distribution Analysis & Prediction Tool
EFD	Early Fault Detection
EIA	Enhanced Ignition Analysis
EPA	Environmental Protection Agency
EPSS	Enhanced Powerline Safety Settings
ESD	Emergency Shutdown
EVM	Enhanced Vegetation Management
EVP	Electric Vice President
FDA	Facility-Damage-Action
EVP	Electric Vice President
FEP	Filsinger Energy Partners
FERC	Federal Energy Regulatory Commission
FHK	Corrosion Inspections
FHL	Atmospheric Corrosion Repairs on Gas Distribution Mains
FHM	Atmospheric Corrosion Repairs on Gas Service Risers
FHN	Atmospheric Corrosion Repairs at Regulator Stations
FIG	Main Leak Repairs
FIH	Service Leak Repairs
FLISR	Fault Location, Isolation, and Service Restoration
FPI	Fire Potential Index
FTI	Focused Tree Inspections
FSR	Field Safety Reassessment
FTE	Full-Time Equivalent
GIS	Geographic Information System
GIS	Gas Insulated Substations
GO	General Order



Term/ Acronym	Meaning
GRC	General Rate Case
GT&S	Gas Transmission and Storage
HBA	Hazard Barrier Analysis
HCA	High Consequence Areas
HFRA	High Fire Risk Area
HFTD	High Fire Threat District
HMI	Human-Machine Interface
IBR	Inverter-Based Resources
IFD	Internal Fault Device
ISA	International Society of Arboriculture
ISM	Independent Safety Monitor
ITS	Industrial Training Services
IVM	Integrated Vegetation Management
JIT	Just-In-Time
KRI	Key Risk Indicator
kV	Kilovolt
LC	Line Corrective
LFF	Liquid Filled Fuses
LiDAR	Light Detection and Ranging
LOTO	Lockout/Tagout
M&C	Maintenance and Construction
MCC	Motor Control Centers
MAT	Maintenance Activity Type
MDR	Minimum Distance Requirements
MED	Major Event Day
MMcfd	Million Standard Cubic Feet per Day
ms	Millisecond
MTI	Marked Tree Inventory
MW	mega-watt
MWC	Major Work Category
NERC	North American Electric Reliability Corporation
NETA	InterNational Electric Testing Association
NRM	Natural Resource Management
NSC	National Safety Council
NUCLA	National Utility Locating Contractors Association
OEIS	Office of Energy Infrastructure Safety
OEM	Original Equipment Manufacturer



Term/ Acronym	Meaning
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
PLC	Programmable Logic Controller
POI	Point of Interest
POMMS	PG&E's Operational Mesoscale Modeling System
PRC	California Public Resource Code
PSPS	Public Safety Power Shutoff
PVFO	Partial Voltage Force Out
QA	Quality Assurance
QC	Quality Control
R3+	Fire potential index score of R3 or higher
RAMP	Risk Assessment and Mitigation Phase
RCC	Risk and Compliance Committee
RCE	Root Cause Evaluation
RFI	Reportable Fire Ignition
RFP	Request for Proposal
ROW	Right of Way
RSAR	Risk Spending Accountability Report
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	System, Applications, and Products in Data Processing
SIF	Serious Injury and Fatality
SME	Subject Matter Expert
SOM	Safety and Operational Metrics Report
SPI	Sierra Pacific Industries
SVP	Senior Vice President
TAT	Tree Assessment Tool
TBM	Time-Based Maintenance
TG	Temporary Generation
TIMP	Transmission Integrity Management Program
TLM	Transmission Line Maintenance
TMS	Ticket Management System
TRAQ	Tree Risk Assessment Qualification
TRI	Tree Removal Inventory



Term/ Acronym	Meaning
T&S	Transmission and Substation
TSBSN	Transmission Substation
UC	Urban Configuration
USFS	United States Forest Service
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
VP	Vegetation Point
WMP	Wildfire Mitigation Plan
WRTC	Work-Readiness Tag Clean-up Team
WSIP	Wildfire Safety Inspection Program
WUI	Wilderness-Urban Interface
XoC	Extent of Condition
YTD	Year to Date



EXECUTIVE SUMMARY

This Independent Safety Monitor (ISM) Report 8 summarizes oversight activities performed between October 1, 2025, and March 31, 2026 (the current ISM reporting period), in alignment with CPUC Resolution M-4855 and the ISM Contract with Pacific Gas and Electric Company (PG&E). The ISM continued to monitor selected safety and risk aspects of PG&E's electric and natural gas operations and infrastructure, building on prior ISM 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 the current ISM reporting period identified observations across several focus areas, including system reliability and outage trends, ignition activity and investigations, refinement, advancement, and evaluation of numerous wildfire mitigations, new risk evaluation and monitoring programs, substation asset management, distribution inspection practices, and vegetation management.

Electric Reliability and Ignition Trends: After a 9-year rise in its System Average Interruption Duration Index (SAIDI) for planned and unplanned, sustained outages (excluding major event days) from 96 minutes in 2015 to 276 minutes in 2024, PG&E experienced a decline in SAIDI in 2025 to 224 minutes. While still placing PG&E in the fourth quartile among U.S. electric utilities, the 2025 reduction was a result of a decrease in both the average duration and frequency of outages across its system, which PG&E attributed to a combination of milder weather in 2025 and the implementation of several new reliability improvement initiatives. PG&E recorded its lowest number of total and CPUC-reportable ignitions in High Fire Threat Districts (HFTD) in 2025, continuing the downward trend observed across all ISM reporting periods. Total facility ignitions fell to 879 in 2025, compared to 1,011 in 2024 and a peak of 1,382 in 2021. When normalized for more extreme wildfire conditions using PG&E's R3+ Fire Potential Index methodology, the ignition rate remained at or near its historic low since 2022. The reduction in ignitions also translated to a reduction in the number of catastrophic wildfires. PG&E experienced no fires caused by its facilities in excess of 100 acres in 2025, and over the past three years PG&E experienced no injuries or fatalities relating to facility fires, no structures destroyed, and 1 structure damaged in 2023 and 1 damaged in 2024.

Ignition Investigations: The ISM reviewed 39 Preliminary Ignition Investigation Reports (PIIRs) during the current ISM reporting period, covering 37 distribution and 2 transmission ignitions occurring between March 2025 and September 2025. Suspected causes included vegetation contact (14), equipment failure (13), re-energization to a fault following vegetation contact (5), and utility activity/improper construction (5). Notably, two ignitions involved equipment with open maintenance repair tags at the time of failure, one involving a liquid-filled fuse with a Priority E tag created 12 days prior to failure, and a second involving improper construction of a tap clamp with a maintenance tag open since 2021, with three subsequent annual field reassessments determining no change in condition.

Wildfire Mitigations: The ISM continues to track the implementation of PG&E's fast trip



programs, which rapidly de-energize powerlines when conditions that can lead to ignitions are detected. While these programs demonstrate a 65% ignition reduction effectiveness, they come at a cost to customers as they experience larger outage impacts. Through various operational improvements, over the past few years, PG&E experienced a 15% reduction in the average number of customers experiencing each fast trip outage, and a 29% reduction in the average duration of each outage. PG&E's ongoing deployment of several new continuous monitoring sensor devices in HFTD provide numerous operational and financial benefits, including more accurate fault location and cause identification, faster power restoration, and reduced wildfire risk. Other new wildfire mitigations detailed in this ISM Report 8 include 1) improved tracking of metal encroachments on steel structures, 2) the introduction of artificial intelligence imaging assistance for asset and abnormal condition identification, 3) reduction of induction risk on idle lines, 4) new transmission ground vegetation removal and satellite monitoring, and 5) a new transmission line span pilot.

Risk Monitoring and Assessments: PG&E continues to refine and expand risk assessment activities in addition to its periodic updating of its core distribution and transmission wildfire risk models detailed in ISM Previous Reports. During the current ISM reporting period, the ISM observed PG&E's assessment activities in relation to its system-wide blackout risk along with services being provided to select critical customers. PG&E is also developing and refining new models to address its urban conflagration risk. The ISM continues to track the development and utilization of a refreshed group of Key Risk Indicators (KRIs). PG&E's Risk and Compliance Committee (RCC) use these operational and cross cutting KRIs to track operational and environmental risk trends.

Substation Asset Management and Capital Investment: The ISM's review of PG&E's substation programs were informed by CAISO's 2025 Annual Maintenance Review, an internal Operational Readiness Verification (ORV), and PG&E's 2024 RSAR. These sources highlighted a pattern in which emergency replacements exceed adopted spending levels while proactive investment is deferred. Emergency substation equipment replacements (MWC 59) recorded approximately \$356.9 million in actual spending against an adopted level of \$175.5 million for 2023–2024, while proactive replacement of switchgear, circuit breakers, and batteries was underspent by approximately 35%. Proactive battery replacement recorded actual spending of approximately \$43,000 against a \$6.9 million authorization.

Substation Maintenance Programs and Asset Condition: PG&E's ORV identified several findings related to maintenance practices, including the absence of a comprehensive asset registry, risk models that do not adequately account for protective relays and other critical minor equipment, a run-to-failure treatment of minor equipment, and high-priority maintenance notifications completed past required due dates. Bay Area staffing was identified as having the highest voluntary turnover in the service territory. During ISM site visits, the ISM reviewed and discussed items identified in CAISO's 2025 Annual Maintenance Review and PG&E reported that issues identified by CAISO had either been corrected or were subject to open maintenance notifications. The ISM also noted that the ORV corrective actions are in various stages of implementation.

Distribution Inspections and E-Tag Field Review: The ISM conducted targeted field reviews of open E-tags in the current ISM reporting period, reviewing 400 open structures, intentionally



weighted toward older notification vintages. Of the 400 structures reviewed, the ISM submitted 19 to PG&E for additional review. PG&E escalated 5 of those 19, four to X-tag status requiring expedited repair and one to B-tag, all of which carried original notification dates between 2019 and 2021. The referral rate was highest among older-vintage notifications (13% for 2019-vintage and 14% for 2021-vintage), while no referrals arose from the 2024–2025 vintage.

Vegetation Management: Effective November 2025, PG&E consolidated its distribution VM programs, integrating Routine and Hazard Patrols, FTI, and TRI into a unified inspection structure while redesignating VMOM as a Weather Driven Event Procedure. The ISM observed that constraint resolution remains an area of ongoing focus for PG&E. As of February 2026, PG&E's active constraint inventory totaled approximately 167,185 constraints across all VM programs, of which approximately 24% had been active for more than 360 days. Environmental Permitting represented the largest constraint category at approximately 35% of total, followed by Operational (23%) and Encroachment Permitting (22%). The ISM continues to identify instances of hazard trees, MDR encroachment, and ANSI A300/BMP non-conformance during field assessments.

GAS OPERATIONS

The ISM's review of PG&E's natural gas operations during this reporting period identified notable observations across five focus areas: safety culture, gas business planning, gas transmission infrastructure, damage prevention, and Kettleman corrective action status.

Safety Culture: PG&E administered its third National Safety Council Safety Barometer survey to Gas Operations personnel in 2025, following prior surveys in 2020 and 2022. Results showed continued improvement across all six assessed categories, with Management Commitment and Organizational Climate showing the most notable gains over the three-cycle period. PG&E utilized the results and trends identified in these surveys to implement changes in areas requiring improvement, launching numerous initiatives to strengthen employee engagement, and address safety improvements, including employee-led Safety Culture Guidance Teams to facilitate discussion of safety culture topics and drive improvements at the local level.

Gas Business Planning and Spending Variances: PG&E manages gas infrastructure investment through its Business Plan Deployment process, under which PG&E funds compliance obligations first, followed by risk mitigation and reliability programs. The ISM observed variances from CPUC-adopted spending levels since the last General Rate Case (GRC). Gas distribution expense and capital spending were below the levels adopted in the GRC, and Gas Transmission and Storage (GT&S) expense spending was also below adopted levels. Gas distribution capital spending was in-line with adopted levels, and GT&S capital spending was below adopted levels.

Gas Transmission Infrastructure Projects: PG&E's G0177 annual report identifies five planned gas infrastructure projects with a combined estimated capital requirement of approximately \$733 million, several of which address compressor station equipment installed in the early 1950s and operating beyond their implied design life. An example is on a Compressor Station on the Baja Path, where an acceleration of equipment failures resulted in PG&E invoking the



GO177 emergency exemption (January 2026) to commence the \$93.5 million construction project before the CPCN review process could be completed. Another potentially looming infrastructure project includes a neighboring Compressor Station, PG&E's single largest identified GO177 project at approximately \$288 million. The project involves nine compressor units also dating to 1951 installations; its in-service date remains to be determined pending resolution of EPA Good Neighbor Plan litigation.

Damage Prevention: The ISM reviewed PHMSA data on excavation damages and locate tickets from 2010 to 2024. PG&E demonstrated a long-term downward trend in distribution dig-in damages over this period, which PG&E attributes to multi-year investments in risk-informed locate strategies, contractor enforcement, and training. PG&E ranks within the top 10% to 25% of AGA peer utilities on damages per 1,000 locate tickets.

Kettleman Corrective Action Status: The ISM continued to monitor the implementation of corrective actions stemming from the Kettleman Compressor Station incident detailed in ISM Previous Reports. PG&E completed and implemented the majority of the corrective actions through updates to procedures, internal processes, training programs, and operational practices. Work continues on the Safety and Culture Achievement Plan, which PG&E now projects to be completed by July 2026, ahead of its original five-year timeline. Other corrective actions yet to be completed include the installation and staging of vent stacks, and clearance supervisor training. Vent stack prototypes are currently in fabrication, and PG&E expects to complete the clearance supervisor training program by the end of 2026.



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 seven reports, hereafter referred to as "ISM Report 1", "ISM Report 2", "ISM Report 3", "ISM Report 4", "ISM Report 5", "ISM Report 6", and "ISM Report 7" (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), October 1, 2024, through March 31, 2025 (published May 15, 2025), and April 1, 2025, through September 30, 2025 (published on October 31, 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 8", covers the reporting period October 1, 2025 through March 31, 2026. It was developed based on the stipulations of the ISM Contract and the reporting directive included within CPUC Resolution M-4855. This ISM Report 8 is designed to summarize the oversight activities performed by the ISM during the reporting period described and the related observations.

This ISM Report 8 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 8 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 8. 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, PG&E undertook the most significant reorganization of its senior leadership structure since the ISM’s engagement began. Unlike prior reporting periods, in which leadership changes were limited in number and involved personnel transitions with no material changes to organizational structure, the changes occurring in the current ISM reporting period reflect both personnel moves and the redesign of the company’s top-level functional groupings.

On December 17, 2025, the Chief Executive Officer (CEO) of PG&E Corporation announced a set of organizational changes effective January 1, 2026, approved by the Boards of Directors of both PG&E Corporation and Pacific Gas and Electric Company. The changes affect seven senior leaders and four functional organization levels. PG&E stated that the total number of officers did not increase as a result of these changes.

The organizational charts included in Figure 1 depict the prior structure and the new structure, highlighting new position titles and the reporting structure for its officers: PG&E Corporation, PG&E Utility, and dual reporting responsibilities.

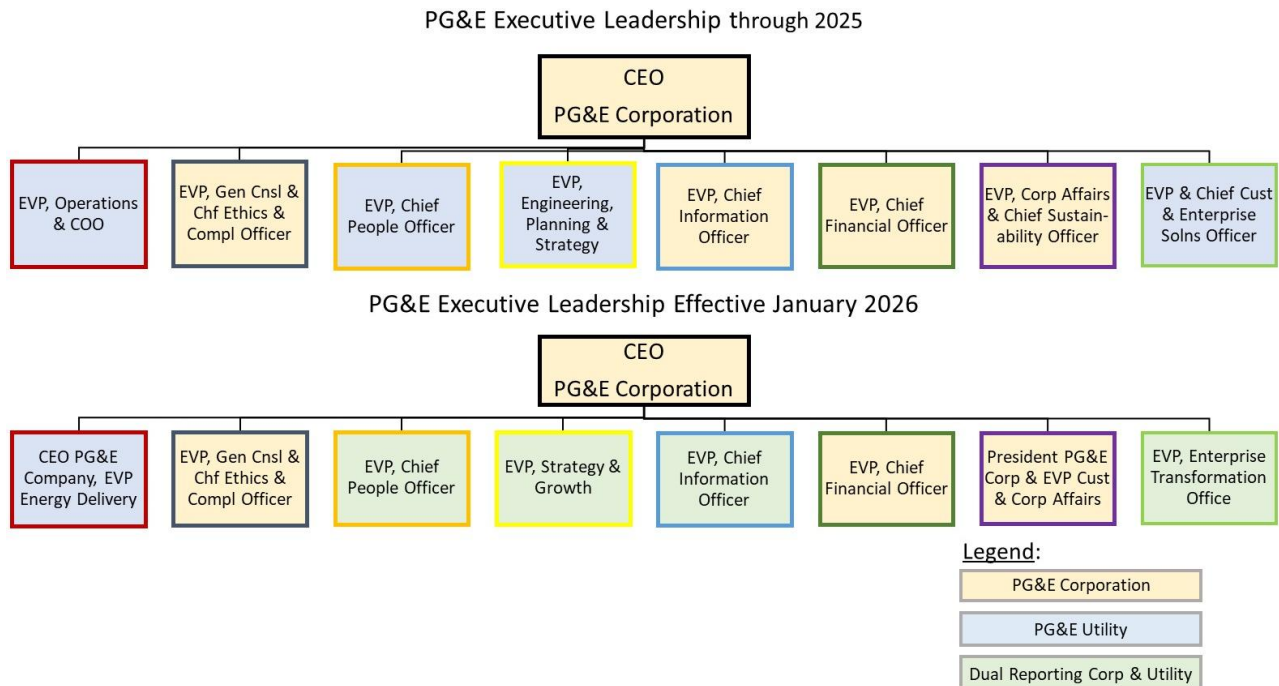


Figure 1: PG&E Senior Leadership Changes Effective January 2026

A significant structural change is the creation of the Energy Delivery function, which will consolidate operational teams, engineering, and shared services under a single leadership structure. The officer who previously served as Executive Vice President (EVP) and Chief



Operating Officer (COO) assumed the dual role of CEO of Pacific Gas and Electric Company (the utility subsidiary) and EVP, Energy Delivery. The COO title was not carried forward or reassigned. The org chart reflects that the EVP, Energy Delivery's direct reports include Electric Transmission & Distribution (now entitled SVP & Chief Delivery Officer for Electric Transmission and Distribution), Enterprise Service Delivery, Gas Transmission & Distribution (now entitled SVP & Chief Delivery Officer for Gas Transmission and Distribution), Wildfire Emergency & Operations, Nuclear Generation, Power Generation, Enterprise Health & Safety (including the Chief Safety Officer), Operations Support, and Business Performance.

Three additional new or enhanced functional groupings were announced alongside Energy Delivery:

- Customer & Corporate Affairs, led by the officer who also assumed the title of President, PG&E Corporation. This officer previously served as EVP, Corporate Affairs and Chief Sustainability Officer. The new group brings together customer engagement, government affairs, marketing and communications, and regional community teams.
- Strategy and Growth, led by an EVP who previously served as EVP, Engineering, Planning & Strategy. The new team is an enterprise function focused on long-term strategic and infrastructure planning across both gas and electric to address California's growing energy demand. It will include a new Enterprise Integrated Planning function with a stated purpose of leading multi-year energy system planning.
- Enterprise Transformation Office, led by the officer who assumed the title of Chief Transformation Officer and EVP. This officer previously served as EVP and Chief Customer & Enterprise Solutions Officer. The new team is focused on modernizing and standardizing business processes, including the evolution of PG&E's Lean operating system.

Additional officer-level changes effective January 1, 2026 include the elevation of the Government Affairs function from Vice President to Senior Vice President (SVP) (reporting to the President, PG&E Corporation); the formalization of the SVP and Chief Customer Officer title; and the creation of the combined role of SVP, Local Customer & Community Engagement and Chief Sustainability Officer.

Prior to the January restructuring, the CEO announced a separate set of personnel changes effective September 30, 2025, following the departure of the Chief People Officer. The officer who had served as Chief Risk Officer (CRO) and SVP, Ethics & Compliance was elevated to EVP and Chief People Officer. The officer who had served as Vice President, Business and Technical Services at Diablo Canyon Power Plant was named SVP and CRO. A successor was named as Vice President, Business and Technical Services at Diablo Canyon. PG&E noted that all three roles were filled through internal promotions.

The leadership and structural changes described above represent a departure from the incremental personnel changes observed in prior ISM reporting periods. PG&E stated that the organizational changes are intended to ensure PG&E is more closely connected to local hometown needs and to meet the growing demand for energy in California in the coming years. Further, PG&E reported that the structure does not impact cost recovery for executive compensation. The ISM will monitor the implementation of these structural changes, as they relate to areas within the ISM's scope of responsibilities.



ELECTRIC OPERATIONS OBSERVATIONS

The ISM's electric operations and infrastructure focus in this ISM Report 8 is directed toward: 1) Reliability, Outage, and Ignitions Trends, 2) Ignition Investigations, 3) Fast Trip Program Updates, 4) Continuous Monitoring, 5) New Wildfire mitigations, Evaluations and Tools, 6) Risk Monitoring and Assessment, 7) Distribution Inspections and Maintenance, 8) Substation, and 9) Vegetation Management.

RELIABILITY, OUTAGE, AND IGNITIONS TRENDS

The following sections present the ISM's observations on three aspects of PG&E's electric system performance during the current ISM reporting period: reliability trends, which track the frequency and duration of customer outages system-wide; outage trends, which examine the underlying causes driving those interruptions; and ignition trends, which assess the frequency, causes, and characteristics of PG&E facility-related ignitions across its service territory.

Reliability Trends

The ISM reports 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.

ISM Reports 2, 5 and 6 detailed the drop in PG&E's capital expenditure on reliability-oriented projects over the past ten years, with targeted reliability investments shifted to support wildfire risk mitigation since 2017. As a result of this shift in investment focus, along with additional outages experienced as a result of the implementation of the Company's Enhanced Powerline Safety Settings (EPSS) and Public Safety Power Shutoff (PSPS) programs, PG&E experienced a 188% increase in its System Average Interruption Duration Index (SAIDI) from 96 minutes in 2015 to 276 minutes in 2024, putting the Company in the 4th quartile among U.S. electric utilities.¹

ISM Report 7 detailed several PG&E management and programmatic efforts specifically designed to improve the Company's reliability metrics. These included 1) the creation of dedicated outage review teams (ORT), 2) improvements in the detection and location of certain high impedance faults, 3) enhanced continuous monitoring, 4) supplemental temporary generation (TG) during planned outages, 5) enhanced field repair capabilities, 6) prioritization of critical operating equipment (COE) maintenance, 7) supplemental patrols/maintenance on high outage circuits, 8) prioritized underground cable replacements, and 9) improved operability of the Company's installed Fault Location, Isolation, and Service Restoration (FLISR) systems.

The improvement of PG&E's system reliability in 2025 is depicted in Figure 2, which shows

¹ Institute of Electrical and Electronics Engineers Benchmark Year 2025 Results for 2024 Data.



PG&E’s Customer Average Interruption Duration Index (CAIDI), its System Average Interruption Frequency Index (SAIFI), and its 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. PG&E noted that although its SAIDI decreased by 19% between 2024 and 2025, the 223.7 minutes of average system sustained outages still puts the Company in the 4th quartile among U.S. electric utilities.

In the current ISM reporting period, the ISM observed PG&E continuing to pursue all of the above noted reliability improvement measures, and working to improve the uptake of available reliability improvement resources (e.g., TG, and enhanced patrol teams to allow immediate repairs where possible), into the beginning of 2026. Through a combination of these continuing efforts and milder weather at the beginning of 2026 versus that seen in the prior 3 years, PG&E experienced a 33% improvement in year-to-date SAIDI through April 20, 2026, versus the prior 3-year average target.²

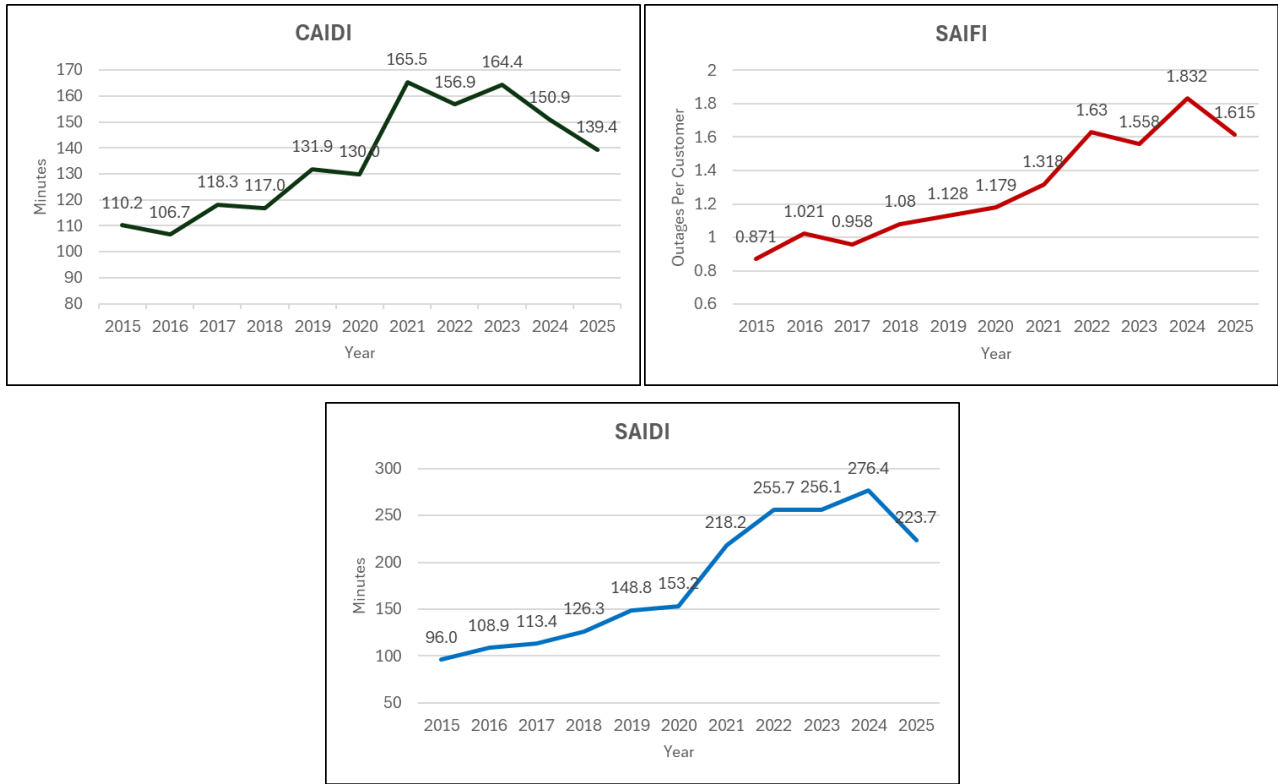


Figure 2: PG&E CAIDI, SAIFI and SAIDI 2015-2025³

² Planned and Unplanned SAIDI, excluding momentary outages and Major Event Day (MED), of 45.53 minutes versus the target of 67.73 minutes.

³ 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.



Outage Trends

As part of its monitorship, the ISM reviews individual causes of PG&E outages and follows up on any trends or outliers in the data. Outages on PG&E’s distribution system are the most common, with approximately 32,500 sustained unplanned distribution outages in 2025 (excluding approximately 2,400 major event day (MED) outages) versus approximately 930 outages on its transmission system (excluding approximately 100 MED outages). Of the approximately 35,000 total distribution unplanned outages, only 44 of these outages occurred at distribution substations, with the balance occurring on overhead and underground lines.

As seen in Figure 3, Equipment Failure is the leading identified cause for distribution sustained outages, and that these types of outages remain near their seven-year highs.

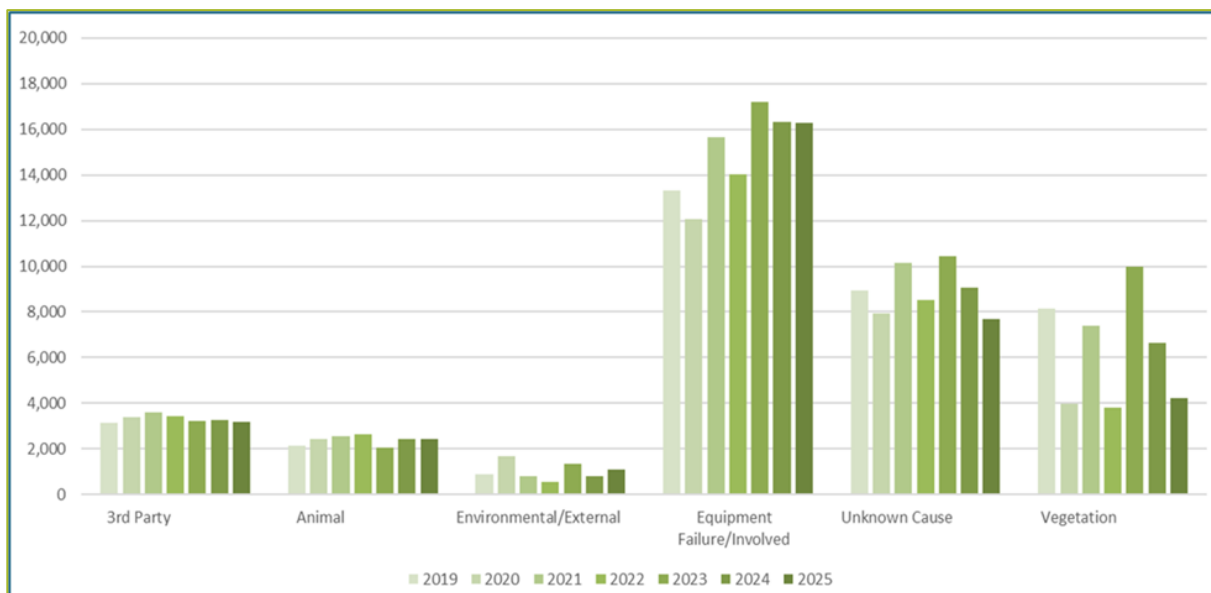


Figure 3: Distribution Sustained Unplanned Outages by Suspected Cause

PG&E tracks Equipment Failure outages across approximately 60 different equipment categories, with the highest frequency types in 2025 being transformers (30%, with 70% of these for overhead assets, and 30% for underground assets), poles (18%), and conductors (12%). While many of the failed equipment categories have seen variations between the years, the one category experiencing a significant increase in outage frequency is distribution poles, which have steadily increased by approximately 250% from a low of 823 in 2020 to a high of 2903 in 2025. During this same period, however, total distribution ignitions relating to pole failures decreased from a high of 80 in 2018 to a low of 6 in 2025. The ISM is conducting further investigations and will be reporting on this divergence in its next ISM report.

Ignition Trends

As seen in Figure 4, which shows total PG&E facility ignitions by wildfire tier from 2014 to 2025, and in Figure 5, which shows total CPUC reportable PG&E facility ignitions by wildfire tier from 2014 to 2025, PG&E experienced its lowest number of total and CPUC reportable ignitions in its High Fire Threat Districts (HFTD) in 2025. CPUC reportable ignitions are those ignitions identified by PG&E that involve PG&E facilities and that have a fire spread in excess



of 1 meter. As seen in these two Figures, approximately 65% of the ignitions in HFTD were CPUC reportable, versus approximately 44% in non-HFTD areas. PG&E noted that the higher percentage of CPUC reportable ignitions in HFTD can stem from a combination of factors including more remote locations, more difficult terrain, a greater abundance of fuel, and increased interaction with vegetation.

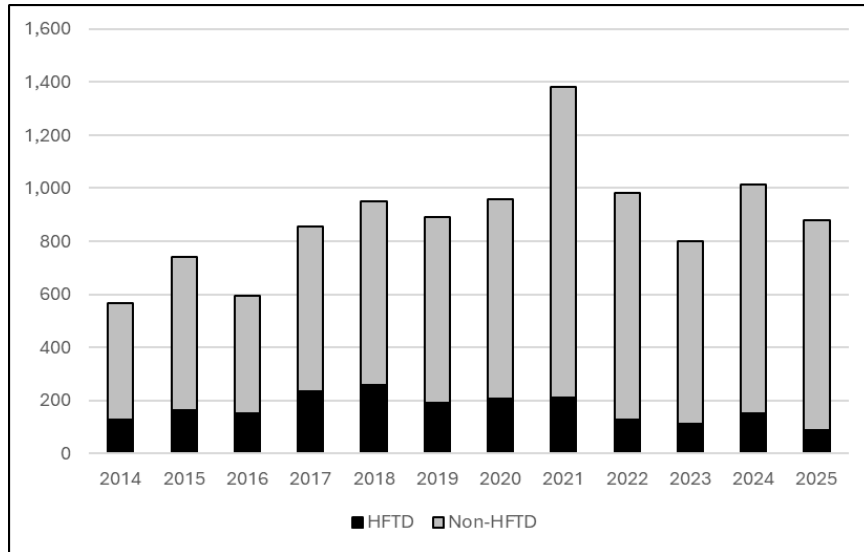


Figure 4: Total PG&E Facility Ignitions 2014 to 2025 by Wildfire Tier

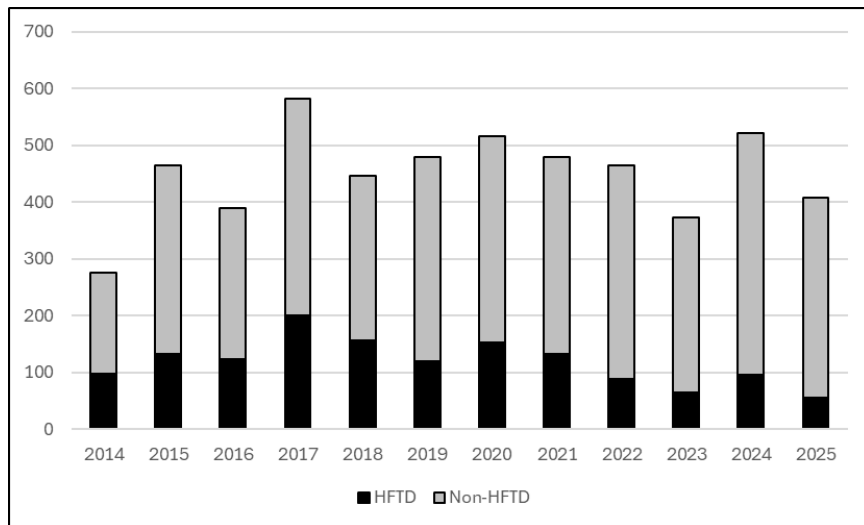


Figure 5: Total CPUC Reportable PG&E Facility Ignitions 2014 to 2025 by Wildfire Tier

Table 1 shows that in 2025, approximately 96% of total ignitions occurred on distribution lines, 4% occurred on transmission lines, and 0.3% occurred in substations.⁴

⁴ Of the 840 distribution ignitions in 2025, 700 were on primary lines, 69 on secondary lines, and 71 on service lines. Of the 36 transmission ignitions in 2025, 12 were on 60 kV lines, 10 were on 70 kV lines, and 14 were on 115 kV lines.



Table 1: Total PG&E Facility Ignitions 2014 to 2025 by Asset Class

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Distribution	537	708	558	802	900	852	915	1,349	951	775	981	840
	95.0%	95.7%	94.1%	93.8%	94.7%	95.1%	95.6%	97.6%	96.7%	96.8%	97.0%	95.6%
Transmission	25	30	32	50	46	39	36	27	30	24	29	36
	4.4%	4.1%	5.4%	5.8%	4.8%	4.4%	3.8%	2.0%	3.1%	3.0%	2.9%	4.1%
Substation	3	2	3	3	4	5	6	6	2	2	1	3
	0.5%	0.3%	0.5%	0.4%	0.4%	0.6%	0.6%	0.4%	0.2%	0.2%	0.1%	0.3%
	565	740	593	855	950	896	957	1,382	983	801	1,011	879

Figure 6 shows the cumulative CPUC ignitions over 2025 including the 2025 Target, versus those over 2024 and those over the 2022-2024 3-year average.

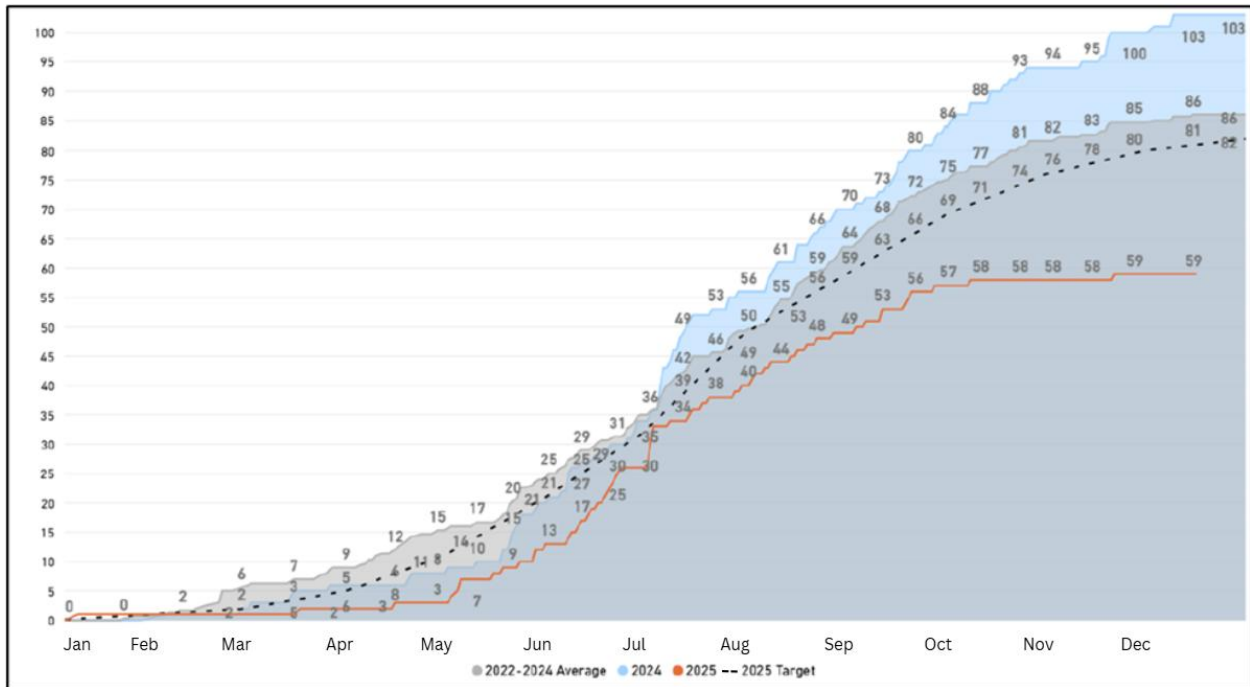


Figure 6: 2022-2025 Cumulative CPUC Reportable PG&E Facility Ignitions in HFTD and HFRA

Since the number of ignitions in any particular year is dependent upon the severity of environmental conditions that can occur in that year, PG&E employs weather normalization to factor in these variations in annual conditions. For its normalization, PG&E uses CPUC reportable ignitions that occur in HFTD during the more extreme Fire Potential Index (FPI) conditions of R3, R4 or R5 on the FPI rating scale (R3+), where the majority of catastrophic fires have occurred, normalized by the number of circuit mile days (CMD) that its HFTD circuits were in R3+ conditions. As seen in Figure 7, when PG&E considered R3+ ignition rates by 100,000 CMD in HFTD, the normalized ignition rates decreased steadily from 2017 through 2022, and have remained at or near their lows since 2022.

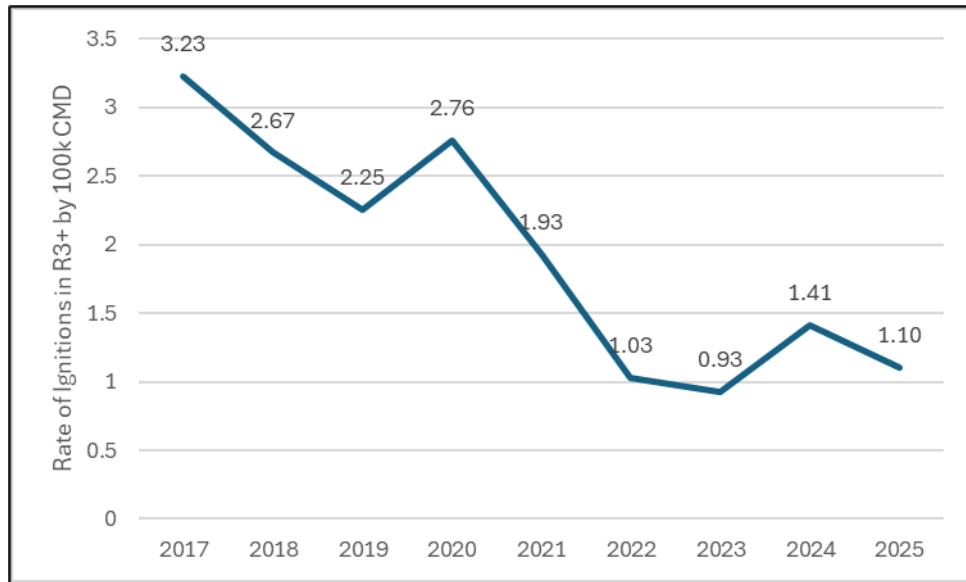


Figure 7: Weather Normalized CPUC R3+ Ignition Rates in HFTD by 100k Circuit Mile Days

As with outages, the ISM reviewed trends in suspected ignition causes, and observed that most categories in HFTD were either flat (such as 3rd party contact) or in decline. As noted above in the Outage Trends section, the ISM is investigating the large decrease in pole failure ignitions in light of the corresponding large increase in pole failure related outages.

In 2025, conductor failures caused 42% of the CPUC reportable equipment-caused ignitions in HFTD. PG&E conducted its own investigation into the nature of these conductor failures, and Figure 8 provides a breakdown of these ignitions by cause and by service type.

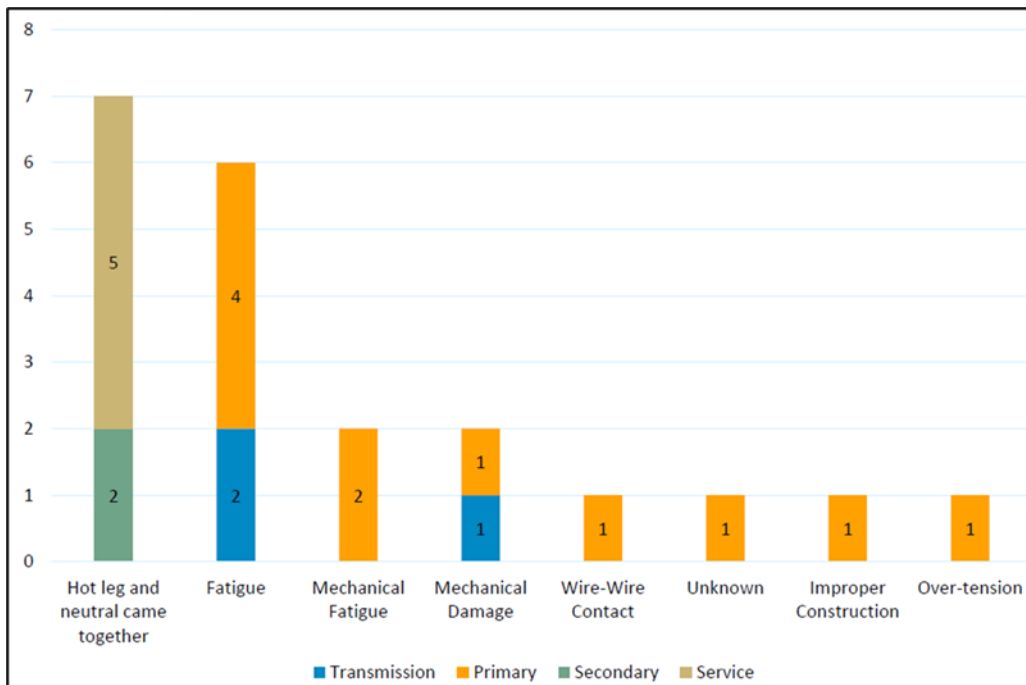


Figure 8: Conductor Failure Ignitions in HFTD by Cause and Service Type



As part of its analysis, PG&E noted that:

- hot leg and neutral contact caused all secondary and service conductor ignitions, with contributing factors including improper construction, proximity to connectors, overload, and ultraviolet light damage.
- fatigue caused most primary conductor ignitions. Contributing factors include possible reuse of old conductor, power surges, improper construction, and over-tensioning.
- fatigue was attributed to two of three transmission conductor ignitions. These were both likely related to wind-induced vibrations.

ISM Report 7 provided details on PG&E’s efforts to enhance construction training and to update its construction standards to minimize hot leg and neutral contact in the future, plus PG&E’s efforts to introduce service line breakaway connectors to minimize failed energized service conductors reaching the ground. To assist in identifying damaged distribution conductors, PG&E is also introducing new aerial drone scans of high-risk conductor spans in 2026. To address transmission conductor fatigue, as detailed later in this ISM Report 8, PG&E launched a pilot in 2024, which it further expanded in 2025, to evaluate inspection methods for assessing mid-span conductor integrity.

As part of its review, the ISM has also tracked trends in PG&E caused fire size. As shown in Table 2, there were no fires in excess of 100 acres in 2025 in HFTD. Over the past three years, PG&E experienced no injuries or fatalities relating to facility fires, no structures destroyed, and 1 structure damaged in 2024⁵ and 1 damaged in 2023. The one >5000-acre fire in 2024 (named the Sites fire) was reported to the ISM as having occurred in HFTD with a suspected cause of vegetation contact. The Sites fire burned 19,195 acres with no structures or injuries reported.

Table 2: Fire Size of PG&E Facility Ignitions in HFTD

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
<1 meter	28	30	23	29	97	66	49	76	38	49	52	28
1 meter to 0.25 acres	60	94	87	114	99	79	85	94	71	42	62	41
0.26 to 9.99 acres	32	28	29	56	40	33	58	30	11	18	23	16
10 to 99.9 acres	1	6	4	13	6	2	7	5	4	3	8	1
100 to 999 acres	0	0	1	3	1	1	0	1	0	1	1	0
1,000 to 4,999 acres	1	0	1	3	0	0	0	1	0	0	0	0
> 5,000 acres	0	1	0	10	1	1	1	1	1	0	1	0

IGNITIONS INVESTIGATIONS

In ISM Report 6, the ISM provided its initial observations on PG&E’s Enhanced Ignitions Analysis (EIA) group, and its primary deliverable, the Preliminary Ignition Investigation Report (PIIR), which provides a comprehensive investigative analysis into the circumstances

⁵ The 2024 Pay Fire burned 77 acres and damaged multiple vehicles, a deck, and hangers at the Placerville Airport. In data provided to the ISM, PG&E considered the damage to the Placerville Airport hangars as damage to one structure.



and suspected root causes of certain in-scope ignitions.⁶ 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, its Applied Technology Services (ATS) engineering laboratory, and its Asset Failure Analysis (AFA) group.

The ISM reviewed 39 PIIRs during the current ISM reporting period which were completed and issued between August 2025 and January 2026. These PIIRs cover 37 distribution and 2 transmission ignitions which occurred from March through September 2025. The suspected causes of these ignitions include 14 attributed to vegetation contact, 13 to equipment failure, 5 to re-energization to a fault after vegetation contact, 5 to utility activity/improper construction, 1 to 3rd party contact, and 1 with an unknown cause. Twenty-one of these ignitions involved ATS and or AFA conducting technical investigations into the root cause of the ignition and extent of condition reviews. All ignitions involving vegetation contact received follow-up vegetation management investigations as detailed later in this ISM Report 8.

Two of the ignitions involved the failure of equipment which had an open maintenance repair tag relating to the cause of failure. One of these involved a fuse failure, where PG&E identified a low liquid condition during inspection, and a priority E tag was created for the liquid-filled fuse 12 days prior to its failure.⁷ The other open repair tag related to a tap clamp which ATS noted was incorrectly installed in accordance with PG&E's standards. PG&E originally generated a Priority E maintenance tag for the improper construction in June 2021 with an initial due date of June 2022. PG&E informed the ISM that subsequent annual field safety reassessments (FSR) in 2022, 2023 and 2024 determined that there was no change in condition, that no tag priority change recommendations were made, and that the overdue tag remained open at the time of the incident.

These PIIR also detailed 8 corrective action plans (CAPs) created to address root causes of specific ignitions. These CAPs included 1) a requirement for supplemental training and to identify and prioritize methods to increase visibility on complicated circuits to assist in minimizing re-energizing into a fault missed during patrol, 2) supplemental training to address

⁶ PIIR are currently undertaken for all CPUC reportable ignitions in HFTD/HFRA and in Non-HFTD buffer areas that are EPSS enabled during R3+ FPI conditions. 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. Ignitions which result in a fatality or personal injury requiring in-patient hospitalization, significant public attention and/or media coverage, or property damage to the utility or others if above \$200,000 are required to be reported in separate Electric Incident Reports.

⁷ Risks involving low liquid filled fuses were detailed in ISM Report 7, and PG&E stated that AFA is currently developing a prioritization strategy to address how these open tags should be addressed, with mitigation efforts focused on those presenting the highest ignition risk. Low liquid filled fuses and their notification priority changes are discussed further in the Distribution Inspections and Maintenance section under the Year-over-year B Tag Trends section.



poor workmanship during construction,⁸ 3) updated construction standards, and 4) an evaluation of the possible need for system-wide proactive damper installation on certain transmission lines based on span length and tension information.

At the end of 2025, the EIA group generated a year-end compilation of the 42 hazard barrier evaluations conducted during the year. Each Hazard Barrier Analysis (HBA) section evaluates which risk mitigations/barriers were in place (or could have been in place but were not in scope for that asset), the expected versus observed performance of the barrier, and an evaluation of why the barrier did not prevent the ignition event. PG&E states that it uses this analysis as a learning and feedback tool, where the failure of the barrier to perform as expected may lead to corrective actions.

Figure 9 shows a breakdown of those ignition mitigation barriers that did not perform as expected. PG&E assessed five barriers as potentially impacting ignitions, with the most commonly assessed barrier for proper construction and installation. Four of these related to improperly installed service connectors, and one related to inadequate application of corrosion inhibitor on a connector. PG&E identified that post-outage patrols that did not perform as expected, and which led to re-energization into faults after vegetation contact ignitions, occurred three times.

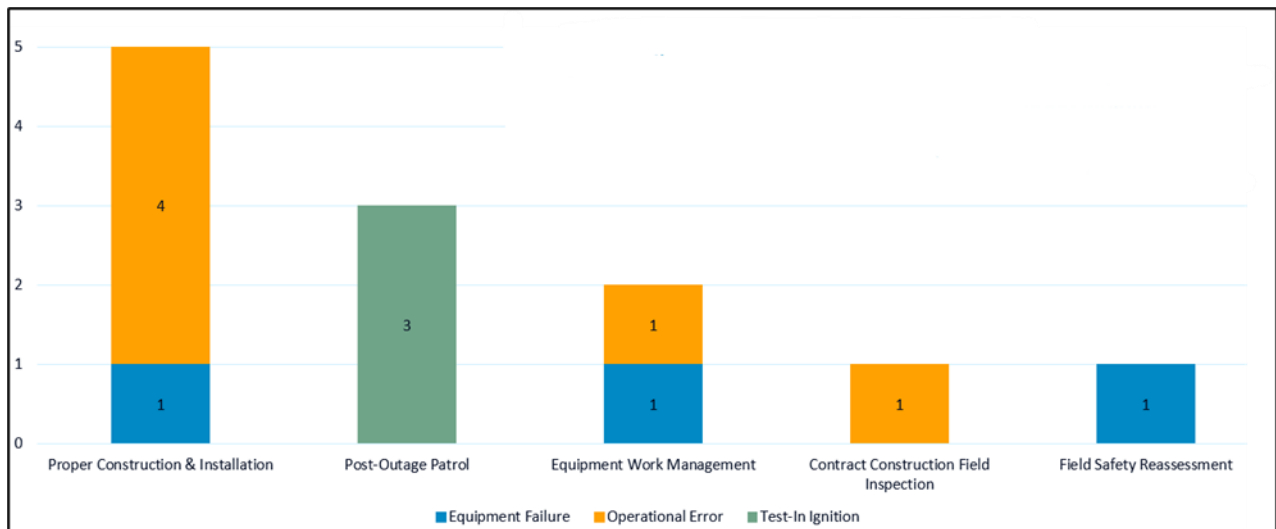


Figure 9: 2025 Barriers That Did Not Perform as Expected

The HBA also investigates which ignition mitigation barriers, selectively used or being rolled out by PG&E elsewhere in its service territory, were not present at the ignition location, but may have assisted in the mitigation of the ignition had they been available. Figure 10 shows a

⁸ PG&E stated that AFA identified that poor workmanship is increasingly becoming a common problem of conductor and connector preparation, and proposed working with PG&E’s Quality Assurance team to determine whether this is a systemic issue. To address this increase in frequency, the ISM has observed PG&E introducing additional training for its construction teams, and introducing new construction standards or evaluations, including: 1) the use of breakaway service connectors detailed in ISM Report 7, 2) updating service conductor standards to utilize covered neutral cable, and 3) an evaluation to assess proactive identification of broken service neutrals.



breakdown of the top 10 cited opportunistic barriers. Note that these are not mutually exclusive, and that several opportunistic barriers may be applicable to individual ignitions. Gridscope (detailed later in this ISM Report 8) was most frequently assessed as an opportunity. For vegetation contact, Gridscope provides an opportunity to more rapidly determine the contact location and to suppress potential ignitions. For re-energization into a fault, PG&E identified Gridscope as a leading opportunity to identify trouble before testing-in. PG&E also identified covered conductor as a leading opportunity for mitigating vegetation, wire-wire contact, and third-party contact ignitions. The use of the remaining 8 opportunistic barriers has been detailed in this and ISM Prior Reports.

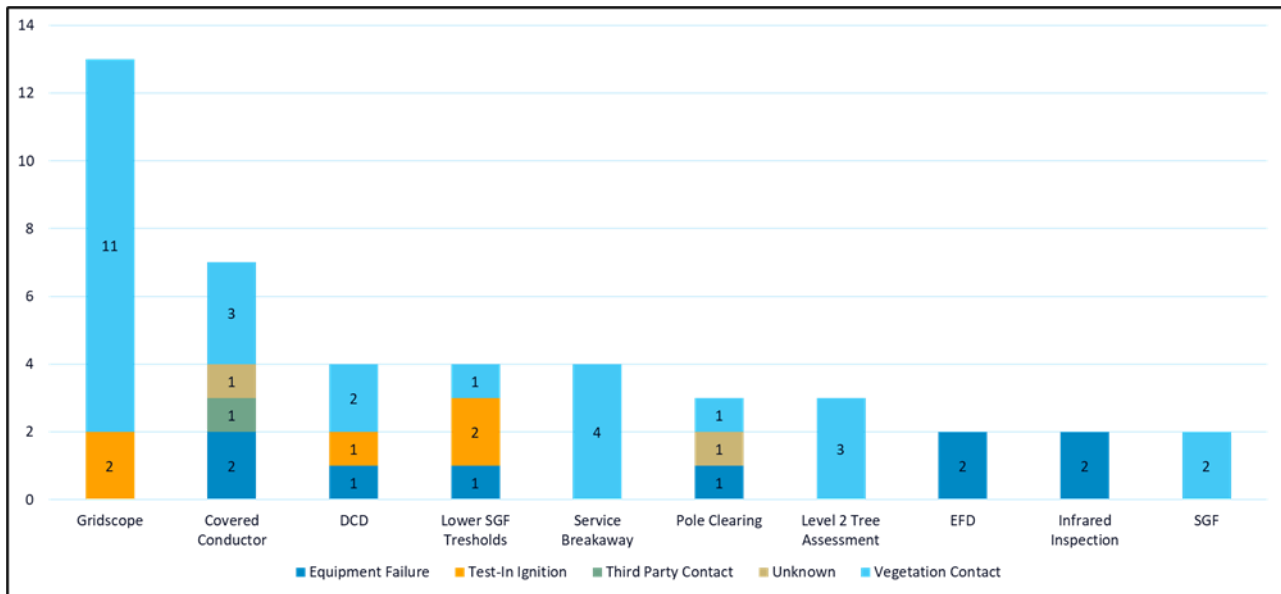


Figure 10: 2025 Top 10 Opportunistic Barriers

FAST TRIP PROGRAM UPDATES

PG&E’s Fast Trip programs, which include EPSS, Downed Conductor Detection (DCD) and Partial Voltage Force Outs (PVFO), remain key wildfire mitigation measures, 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 these three programs since their initial piloting in 2021, and on the expansion of EPSS enabled lines to their current 46,000 distribution miles covering approximately 2 million customers. As previously reported, PG&E stated that under weather normalized, more extreme, R3+ FPI conditions, its Fast Trip mitigations showed a 69% ignition reduction effectiveness when compared to the pre-EPSS/DCD 2018-2020 period. These additional wildfire mitigations, however, come at a cost to PG&E customers, as they experience larger outage impacts than would have occurred without this extra layer of protection in place.

EPSS Program and Trends

PG&E’s Fast Trip program team is currently comprised of over twenty-five full-time employees, and, as part of its monitoring, the ISM observes the group’s weekly operating reports and select Fast Trip weekly group meetings. Table 3 provides an overview of EPSS



performance over the 2022 to 2025 period.

Table 3: EPSS Data: 2022 to 2025

	2022	2023	2024	2025
EPSS Enabled Circuit Mile-Days (CMD)	6,031,039	5,644,900	6,356,531	5,710,000
EPSS Customer Minutes Enabled (CME, billions)	300.3	257.6	349.8	248.0
EPSS Outages	2,379	2,263	2,820	2,411
EPSS Outages per 10k CMDs	3.94	4.01	4.44	4.22
EPSS Outages per 1B CME	7.92	8.79	8.06	9.72
Reportable Fire Ignitions on EPSS Enabled Lines	31	22	47	18
RFIs per 10k CMDs	0.05	0.04	0.07	0.03
RFIs per 1B CME	0.10	0.09	0.13	0.07
EPSS CAIDI (min)	176	193	150	137
EPSS CESCO	889	870	818	756
Response Time Within 60 minutes	89%	91%	93%	94%
Average Full Restoration Time (min)	351	367	410	352
% Restorations <= 60 minutes	7.4%	11.6%	13.7%	14.1%
% Restorations > 12 hours	13.3%	16.0%	13.4%	12.5%
Total Customers Experiencing EPSS Outages	2,083,985	1,972,285	2,306,579	1,820,822
Unique Customers Experiencing EPSS Outages	770,441	726,708	917,227	838,976
Medical Baseline Customers	134,622	129,825	128,828	98,710
Life Support Customers	93,876	92,674	93,825	71,969
Critical Customers	34,841	33,456	38,327	30,003
Schools	4,573	4,301	4,989	4,199
Hospitals	185	260	232	216
Well Water Dependent Customers	2,375	4,344	6,475	8,472
Outage Cause (% of total)				
3rd Party	9.5%	9.6%	9.5%	9.3%
Animal	16.5%	12.2%	12.4%	14.3%
Company Initiated	4.5%	11.3%	13.2%	13.7%
Environmental/External	0.5%	3.2%	1.4%	7.5%
Equipment	12.3%	13.6%	13.5%	13.8%
Unknown	45.6%	39.2%	38.1%	31.9%
Vegetation	11.2%	10.9%	11.8%	9.5%

As seen in Table 3, although the number of EPSS outages remained relatively stable over this four-year period, PG&E experienced the lowest number of reportable fire ignitions (RFI) on EPSS enabled lines in 2025, and the lowest number of RFI's normalized per EPSS circuit-mile



days and by customer EPSS enable minutes.⁹

Due to an increase in the amount of power line sectionalization that PG&E continues to undertake each year¹⁰, PG&E also saw the lowest number of customers experiencing sustained outages (CESO) from each EPSS outage. As detailed in ISM Previous Reports, PG&E implemented a number of actions over this four-year period to improve its EPSS outage response and restoration performance. As seen in Table 3, these actions helped drive PG&E's average response time within 60 minutes, its average full restoration time, and its CAIDI on EPSS enabled lines to their lowest levels.

PG&E stated that its adoption of a new tool in 2025 also assisted in lowering its average EPSS customer outage duration. A new 'test-in' tool was developed and piloted in three divisions in 2025. In normal EPSS operations, PG&E determines if higher wildfire risk EPSS enablement conditions are met once per day, and if a line segment is enabled, that enablement remains active for the following 24-hour period. Environmental conditions, however, may change within that 24-hour period, and the new test-in tool allows field personnel to receive meteorological updates within each 24-hour enablement period. For example, if rain reduced wildfire risk at a particular location in between EPSS enablement determination periods, and the test-in tool indicates that enablement conditions are not currently being met, field personnel can re-energize a line after an EPSS de-energization without the normal line patrol. In the event the fault condition no longer exists, service can be immediately restored. If the fault condition persists, and the line is again de-energized, then normal EPSS patrol procedures are followed during these lower risk periods.¹¹ PG&E is still assessing the results of the 2025 pilot before determining whether the test-in tool will be adopted across all divisions.

As also noted in ISM Previous Reports, the Fast Trip team continues to refine its efforts at identifying the cause of EPSS outages, with the number of EPSS outages classified with an "Unknown" cause being reduced by 30% over the past four years to the 31.9% level. PG&E stated that improved causation data allows it to better target mitigations or fine tune device settings to further reduce customer impacts in the future. Although PG&E stated that many of

⁹ PG&E states that several factors can influence the year-to-year changes that have been seen in CMD and CME shown in Table 3, including weather conditions and the number of circuit miles with EPSS enablement capability. PG&E notes that one operational change in particular contributed to the 2024 to 2025 decrease. Prior to 2025, roughly one-third of EPSS circuits classified as non-coastal (i.e., inland) remained enabled for the duration of the peak enablement season once they received their initial trigger. PG&E states that this approach reduced operational churn, while coastal circuits continued to cycle on and off based on changing conditions. In 2025, PG&E notes that improvements in both technology and operational processes allowed it to align non-coastal circuits with real-time wildfire-risk signals. As a result, these circuits were enabled and disabled more dynamically, leading to fewer total days enabled for many of them.

¹⁰ Sectionalization helps isolate an EPSS outage to shorter circuit segments, which in turn allows for faster restoration of service for more customers which helps reduce the number of customers that individual EPSS outages can impact. PG&E added 209 sectionalizing devices in 2023, 186 devices in 2024, and 112 in 2025.

¹¹ PG&E identified 11 instances during the 2025 pilot where the test-in tool was successfully used to support restoration. PG&E states that 1) 2 of the 11 outages were safely restored in under five minutes, converting them to "Momentary" outages as defined by IEEE Standards, and 2) 9 of the 11 outages had a combined CAIDI of 21.1 minutes, which was an 80% reduction from the average 2025 EPSS CAIDI of 137 minutes.



its Unknown outages may be due to vegetation or bird contact, where a striking branch or bird may not be found during a patrol, the reduction in Unknown-cause outages seen in Table 3 more closely matches the increase in Environmental/External and Company Initiated outages. PG&E states that lightning strikes that cause EPSS outages, which make up the majority of the Environmental-caused outages, were often classified as Unknown outages in the past. To help reclassify these outages, the Fast Trip team began working with ATS and PG&E's meteorological team to track the location of historical lightning strikes, and to attribute these strikes as the cause where applicable.¹²

The increase in Company Initiated outages on EPSS enabled lines from 4.5% of total EPSS outages to 13.7% seen in Table 3 was first detailed in ISM Report 7. 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 immediately reported to the Distribution Control Center (DCC), allowing safe and rapid restoration and proper documentation of the cause of the outage.

In an attempt to reduce vegetation and animal contact outages on EPSS enabled lines which have historically experienced high outage counts, PG&E introduced supplemental vegetation management and animal mitigation programs that were detailed in ISM Reports 6 and 7. Further details on the current vegetation management actions on EPSS enabled lines are further detailed in the Vegetation Management (VM) section of this ISM Report 8. In an effort to reduce animal contact outages on EPSS enabled lines, PG&E installed 132 animal mitigations in 2023, 1,840 in 2024, 1,665 in 2025, and plans an additional 1,530 in 2026.

In an attempt to reduce the impact on customers experiencing multiple EPSS outages, PG&E also introduced a new aerial drone patrol program in 2025. PG&E completed patrols on 9 of its EPSS circuits with the highest number of historical Unknown caused EPSS outages in 2025 and designed the program to identify imminent or near-term failure conditions. The 2025 program identified 86 high priority conditions (5 A tags, 13 X tags, and 68 B tags, with 1 animal and 2 vegetation and the balance equipment-related) requiring repair. PG&E is continuing this program in 2026, planning to complete patrols on high outage frequency segments of 6 circuits before the start of EPSS enablement later in the year.

After reviewing historical ignition data, PG&E identified an approximately 4.5 times increase in ignitions in HFTD during more extreme R4+ FPI conditions during the 2022-2025 period for

¹² Environmental-caused outages include outages caused by forest/grass fires, which totaled 16 (5%) of the 307 Environmental outages over the past four years. EPSS outages attributed to lightning strikes over the past four years were 10 (2022), 73 (2023), 33 (2024) and 175 (2025).



EPSS de-energization delay times above 60 milliseconds (ms).¹³ In order to test whether faster trip settings can help PG&E reduce ignitions during more extreme wildfire conditions, PG&E is conducting a pilot in 2026 on 10 distribution circuits, covering 930 miles. This pilot is designed to inform future zero delay expansion while balancing reliability impacts. PG&E states that the extremely dry conditions under which catastrophic wildfires occur require less energy to cause an ignition, and that zero-delay can further mitigate the probability of catastrophic ignition by reducing fault energy up to 55% compared to traditional EPSS.¹⁴ Zero delay settings on the 142 EPSS devices on these pilot circuits will only be activated when R4+ FPI conditions are met along with other minimum fire potential conditions.

Since these faster trips can also increase customer outage impacts, PG&E is mitigating possible reliability impacts by installing additional Gridscope continuous monitoring (CM) devices (detailed in the CM section of this ISM Report 8) on these pilot circuits as a means of shortening restoration times. PG&E is also planning on enhancing the deployment of on-call staffing during periods of zero delay enablement, and modifying its patrol scope should multiple devices trip during a single fault event.

Downed Conductor Detection and Partial Voltage Force Outs

The ISM detailed DCD and PVFO technologies and their expansions in ISM Previous Reports. Of the 217 DCD outages in 2025 (down from 360 in 2024), following post-outage patrols and investigations, PG&E identified 45 of these as having likely mitigated potential ignitions (down from 55 in 2024). PG&E experienced 72 PVFO outages in 2025 (up from 31 in 2024 and 25 in 2023).¹⁵ While 22% of these smart-meter detected forced outages did not have a cause identified with them, the remaining forced outages were attributed to equipment failure (45%), animal contact (11%), vegetation contact (8%), 3rd party contact (8%) and other (6%).

CONTINUOUS MONITORING

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, and the methods used to

¹³ Over the 2022 to 2025 period, PG&E experienced the following HFTD ignitions during R4+ FPI conditions: 3 with EPSS device delays of 0 ms, 4 with 0-30 ms delays, 2 with 30-60 ms delays and 11 with delays >60 ms.

¹⁴ Zero delay works by further reducing fault clearing times from 9 cycles in traditional EPSS to 4 cycles – reducing the energy of the fault and lowering the probability of ignition as demonstrated through observation and by PG&E's lab testing at ATS. The largest change in total clearing times from Zero-delay compared to EPSS occurs on the protection zone closest to the circuit breaker where the highest fault duties and fault currents co-occur with the longest clearing times to produce the highest energy faults and higher ignition per outage rates.

¹⁵ PG&E states that the variance between 2024 and 2025 is primarily driven by the implementation of a new PVFO tracking process in Q4 of 2024. PG&E notes that it operationalized PVFO ahead of the tracking release to provide immediate public-safety benefits, and while PVFOs were occurring and being addressed in the field prior to Q4 2024, the new system now allows field personnel to more consistently log, categorize, and report PVFOs in a standardized manner. PG&E states that because of this timing, it is more likely that the increase from 31 PVFOs in 2024 to 72 in 2025 reflects improved tracking and reporting, rather than a material rise in actual force-out events year-over-year.



determine their initial placements, have been described in ISM Previous Reports and are detailed in PG&E’s Wildfire Mitigation Plans, Figure 11 provides a simplified description of these technologies and their benefits.

SmartMeters	Gridware Gridscope	Early Fault Detection	Distribution Fault Anticipation
<ul style="list-style-type: none"> • 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 	<p>Gridscope devices provide continuous monitoring that advances wildfire safety and system resiliency:</p> <ul style="list-style-type: none"> • 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, wildfire, and physical stresses 	<p>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</p> <p>By spotting early signs of equipment stress, we can prevent faults from escalation into outages and ignitions.</p> <p>Detection condition types:</p> <ul style="list-style-type: none"> • Broken/damaged conductor/splices • Broken/damaged insulator • Tie-wire, bonding wire issues • Failing service transformers • Vegetation encroachment • Fuse Cutout Malfunction 	<ul style="list-style-type: none"> • 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: <ul style="list-style-type: none"> • Fault Induced Conductor Slap • Arcing Underground Elbows • Series Arcing <p>Benefits:</p> <ul style="list-style-type: none"> ✓ Enhances reliability ✓ Prevents outages and wildfires ✓ Increases operational efficiency

Figure 11: Continuous Monitoring Technologies and Benefits

Table 4 provides a summary of the total number of units of each CM technology that PG&E installed through the end of 2025 and is planned for installation in 2026.

Table 4: PG&E Continuous Monitoring Deployment¹⁶

Technology	EOY 2025 Total Installs	End 2025 Percentage of HFTD/HFRA Distribution Lines Covered	2026 Planned Installs	Est. End 2026 Percentage of HFTD/HFRA Distribution Lines Covered
Gridscope	20,068	5.0%	10,000	9.0%
Early Fault Detection	536	3.6%	180	6.3%
Distribution Fault Anticipation	112	32.5%	15	43.1%

During 2025, PG&E identified 237 instances where Gridscope devices provided operational benefit¹⁷ to the Company, 50 instances where EFD/DFA provided benefit, and 662 instances where its smart-meter based SmartDetect program (previously called Electric Distribution Analysis & Predication Tool (EDAPT)) provided benefit, including the identification of 41 instances of energy theft. PG&E is in the process of automating how it calculates the quantity and value of this energy theft, and currently estimates the annualized avoided revenue loss from energy theft identified by SmartDetect in 2025 at approximately \$1.4 million.

PG&E’s CM team also works with PG&E’s EIA team to validate hazardous conditions identified

¹⁶ SmartDetect performs analytics at the transformer level using data from PG&E’s entire communicating SmartMeter population. Not all customers have SmartMeters (as customers have the option to opt-out), and not all installed SmartMeters are able to connect to PG&E’s SmartMeter radio frequency mesh network. PG&E states that 500,917 meters are monitored in HFTD (96%) and that 5,190,409 are monitored in non-HFTD.

¹⁷ Benefits can include ignition prevention, redirecting of field personnel to the hazard, improved response, patrol, and restoration times, financial benefit, asset health data, public hazard identification, and outage cause identification.



by CM devices that likely would have led to an ignition. During 2025, PG&E determined that the use of CM technologies avoided 17 ignitions (SmartDetect 13, Gridscope 2, EFD 1, and DFA 1). To help quantify the possible mitigated impacts of these avoided ignitions, PG&E runs two 8-hour fire simulations at 4 am and 4 pm on the date of the finding, using historical environmental conditions at that specific location. The fire simulation then calculates the potential acres and structured burned at each of those two times, along with an estimate of financial loss. PG&E estimated financial losses mitigated between \$9.3 million and \$17.7 million based on the simulations run on those 17 mitigated ignitions.

Other 2025 CM benefits quantified by PG&E include:¹⁸

- Outage Response: approximately 158,000 trouble shooter minutes saved, equivalent to approximately \$0.7 million in savings.
- Find & Fix (PG&E field personnel fix the situation themselves without a need to call or schedule a follow-up crew): \$1.3 million in savings.
- Find & Repair (A and X tag finds required to be repaired within 1 and 7 days): \$1.9 million in savings.
- Find & Schedule (B and E tag finds): approximately \$1.9 million in savings.
- Customer unplanned outage/reliability savings: 12 million customer minutes saved with a financial benefit of approximately \$37.6 million.

While PG&E states that it sees significant benefits from the continued deployment of additional CM technologies and from refinements to its smart meter-based monitoring, it also notes that it is still too early to calculate benefit/cost ratios for these technologies given the current small population size, and the range of benefits that each technology independently provides.

In addition to Gridscope, EFD, DFA and SmartDetect, PG&E also intends to install and integrate 10,000 Advanced Meter Infrastructure (AMI) 2.0 smart meters in HFTD in 2026. PG&E initially piloted the AMI 2.0 meters as part of its EPIC 3.43 program, which evaluated the performance of several distributed intelligence applications. PG&E stated that its initial deployment of the first 10,000 AMI 2.0 units is to obtain experience and key learnings by developing full IT integration of the new meters into its systems, and by operating at scale. 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, should it have a positive roll out of the first 10,000 units, 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.

¹⁸ PG&E states that benefits accrue to PG&E's customers and communities when a condition is identified by CM sensor data, and the analytics are validated on the electric system and proactively addressed. In calculating the financial benefit of the three 'Find' categories, PG&E notes that there are lower units costs associated with resolving CM identified conditions prior to that electric asset's catastrophic failure due to a fault, and that the magnitude of the financial savings benefit is tied to the severity and immediacy of repair of the CM identified condition.



NEW WILDFIRE MITIGATIONS, EVALUATIONS, AND TOOLS

PG&E continues to evaluate and adopt new technologies and operating methods in order to further reduce its wildfire risk. During the current ISM reporting period, the following wildfire risk mitigation workstreams were observed by the ISM.

Metal Encroachments on Steel Structures

Following a September 2023 transmission line ignition and 2-acre fire in HFTD, where a bird contact resulted in energization of the steel pole and metal fence that was contacting it, PG&E's AFA group performed an extent of condition review on metal encroachments. PG&E noted there were 3 separate encroachment tags on this line where a customer owned fence was closer than 8 feet, but that PG&E inspections had missed where the fence was touching the steel pole. As part of its review, AFA identified 43 open encroachment tags for metal touching steel structures, and the ISM has been tracking the closing out of the final open tags.

AFA also met with transmission line Land Services (which deals with encroachment issues, where they try and work with landowners to solve issues), and the Centralized Inspection Review Team (CIRT). Following these meetings, AFA identified several process gaps, including 1) Land Services does not have an effective way for tag notifications in System, Applications, and Products in Data Processing (SAP) to be directed to them for follow-up, and 2) the ignition mode has not been previously captured as an ignition and public safety risk in associated documents.

The ISM tracked the closing out of the three CAPs generated to address these process gaps and observed that the last of these were completed in 2025. PG&E noted that one of the historical issues was that encroachment tags in the Transmission Line Maintenance (TLM) tracker were assigned to Land Services, but that this department was not consistently made aware of these tags. PG&E stated that after coordination between systems, an updated process was developed where notice of encroachment tag generation is now automated and assigned to a Land Services agent (with confirmatory communication) within 24 hours. Before closing any encroachment tag, PG&E's Enterprise Encroachment Abatement Procedure requires agents to perform a go-back inspection. Revisions to transmission line standards, work methods, and inspection job aids were also made to address the recognition of metal encroachments as ignition and public safety risks.

AI Imaging Assistance

Waldo for Splice/Connector Identification

PG&E's 2024 R3+ Task Force (detailed in ISM Report 7) identified that the leading driver for equipment-caused CPUC reportable ignitions during R3+ FPI conditions in HFTD in 2024 were splice, clamp, and connector failures (5 of the 56 R3+ ignitions in HFTD). The Task Force issued a CAP in its year-end report to 'evaluate the feasibility of developing an image detection model to identify connectors on the distribution system'. This stems from connectors not being mapped and classified in PG&E's asset registry.

PG&E employs at least 14 different connector types, with 3 in particular responsible for 65% of connector ignitions over the 2021-2024 period: Insulink (7 ignitions), H-type (6) and



parallel groove (4). In order to better target mitigations for certain connector types (such as pole clearing, or CM device deployment), PG&E must first determine where its higher risk connectors are. One approach, to review historically captured aerial imagery to try and manually identify connectors, was deemed prohibitive due to processing time and cost. PG&E then investigated artificial intelligence (AI) solutions to address this issue and developed its “Waldo” computer vision (CV) to automatically process aerial inspection images of its assets to provide insight into its population of connectors.

Through prior development PG&E determined that Waldo would save 7,600 hours per year versus inspectors performing an equivalent visual asset inventory. In its testing, PG&E determined that Waldo was able to correctly identify the three highest risk connectors with model precision between 79% and 94%. Of the approximately 630,000 HFTD poles not currently receiving annual pole clearing, Waldo has now made predictions on approximately 300,000 exempt HFTD poles and identified approximately 160,000 locations having high-risk connectors.

PG&E stated that its initial intention was for the Waldo project to focus on connectors (specifically those associated with jumpers and pole top equipment) and not splices. In 2026 PG&E plans for Waldo to process an expanded set of aerial inspection records, and is exploring using Waldo results in its pole clearing plan, where results may support the identification of poles that have connector types associated with higher ignition risk. PG&E will also investigate the potential for Waldo to be used on mid-span splices and across its entire system, not just in HFTD. For 2027, PG&E plans to use Waldo for connector identification on all its aerial inspections in HFTD.

Epic 4.22 - Computer Vision Asset Registry Change Detection

EPIC 4.22 is a PG&E research and development project testing the potential and limitations of AI CV to support PG&E’s ongoing efforts to fill asset registry gaps and to maintain a more accurate asset registry beyond connectors, and to support more efficient and effective asset inspections. CV learns from examples of labeled images how to recognize items in photos (e.g., poles, crossarms, insulators) and to flag visible defects. By applying CV to images that PG&E already collects via aerial drone capture, PG&E stated that the project aims to accelerate and further standardize work that today requires time-consuming manual labeling and review.

PG&E is currently testing CV’s ability to identify assets and key attributes from inspection imagery and to compare it against Geographic Information System (GIS) records. PG&E is also testing CV’s ability to flag issues like cracks, flashing, contamination, and other asset conditions on a sample set of components. If the technology proves successful, PG&E states that EPIC 4.22 will work with its inspections teams to determine possible approaches to incorporating the technology to augment inspectors. PG&E notes that CV would augment, not replace, human inspections, and that it is testing CV capabilities to pre-process the imagery for faster and more accurate human inspections, and/or to prioritize which images are inspected by humans first so that more urgent issues are identified sooner.

During the discovery and model evaluation phase, PG&E received approximately 40 responses from vendors, and administered a structured, multi-stage test of 14 vendors and approximately 230 models, testing these models on PG&E data sets. PG&E issued a proof-of-



concept request for proposals in December 2025, and is planning to 1) do final testing of CV platforms, model development tools and analytical capabilities, 2) build a test case model library, 3) measure CV performance in context of PG&E operational workflows and outputs, 4) validate CV outputs with subject-matter experts (SME), and 5) gather insights into potential integration pathways in 2026.

If successful, PG&E states that CV may provide the following benefits:

- Faster hazard detection to support potential ignition reduction: By quickly flagging visible issues in the imagery queue, CV may accelerate field teams' awareness of and ability to address higher-risk equipment.
- More consistent inspections to support improved quality: CV applies the same "rules" every time, helping reduce variability in what gets flagged and to supporting quality control.
- Fewer customer impacts to support potential outage-minute reduction: Earlier identification and prioritization of issues can prevent or consolidate some equipment-related outages.
- Lower review effort to support strategic use of SMEs: Semi-automating image review lets skilled staff allocate more time to sets of images that truly need human judgment.

Idle Lines and Induction Risk

Utilities have been performing substantial reviews of transmission failure modes relative to induction and structure grounding, and during the current ISM reporting period, the ISM observed several PG&E activities in this area. Induction on idle transmission lines can create a wildfire threat because nearby energized lines can induce a voltage onto de-energized lines through electromagnetic coupling. This induced voltage can cause unexpected current flow, leading to arcing if there are faults, damaged insulation, or contact with vegetation on idle lines. PG&E states that unintended energization of idle lines is risky because its protective systems cannot identify performance issues that may be present (e.g., damaged equipment) until energization occurs. It should be noted that even though certain PG&E lines may be idle, these lines still receive the same asset inspections as those lines that are energized and in service.

As of April 2025, PG&E had 20 idle transmission lines, covering 56 miles, with 3 of those lines (covering 2.25 miles) in HFTD. PG&E deemed eight of these lines, including 2 in HFTD, to be abandoned and of no future use, and removed the lines in April and May of 2025. Of the remaining 12 idle lines, PG&E placed 2 back into service, with the remaining 10 identified as being temporarily idle and of potential future use. PG&E assessed two of these lines as having no induction risk, and the remaining 8 lines, including 1 in HFTD, received risk mitigations in July and August of 2025.

As part of its idle line mitigations, PG&E segmented 8 lines based on idle circuit configuration and the results of detailed induction studies. These studies assumed idle line fault scenarios for identified parallel energized lines, and for each analysis the energized lines were placed in peak loading conditions for non-faulted conditions. Idle lines were sectionalized in the field where they no longer paralleled energized circuits and they no longer shared structures with distribution underbuild. PGE& performed field measurements to validate that the mitigations were effective, and to inform additional iterations. PG&E stated that it will continue assessing



if further modeling, segmentation, and/or grounding is required for these 8 transmission lines through annual testing, while also performing annual drone inspections to ensure that any installed segmentation remains safe.

Transmission Ground Vegetation Removal and Satellite Monitoring

PG&E's 2024 R3+ Task Force calculated that 84% of CPUC reportable transmission ignitions from 2021 to 2024 started within 50 feet of a support structure and noted that all PG&E's historical catastrophic fires related to transmission assets originated at the base of the structure. As a supplemental mitigation measure, PG&E performed vegetation clearing around 3,956 transmission structures in 2025. PG&E originally generated a list of 6,705 higher risk structures prioritized using a combination of wildfire risk, wildfire consequence, and avian risk/concern. The final number of structures completed was based on those that could be completed within the \$60 million budget, and those available for work given certain constraints (2,264 were constrained at the time), permitting and work bundling considerations. PG&E states that, subject to external factors, it plans on risk reduction vegetation clearing work on 6,705 transmission structures in 2026, while continuing to maintain the 50-foot vegetation clearance from 2025.

In addition to the clearing of this vegetation, PG&E also began leveraging its use of satellite imagery for transmission vegetation that it began using in 2024 for distribution vegetation to learn more about vegetation health, fuels, and dryness. This 2025 transmission satellite imagery pilot was initially focused on the structures noted above that were cleared, with images taken both before the clearing and then after, with refreshed images available on weekly basis. This imagery allows PG&E to confirm the completion of vegetation maintenance activities, along with monitoring vegetation growth rates in the event that regrowth requires additional clearing. PG&E will continue to evaluate the use of this technology in 2026. PG&E states that it is unable to currently operationalize the use of satellite imagery for transmission vegetation clearance as further work is needed to differentiate dead and dying fuels from bare soil.

Transmission Line Span Pilot

PG&E launched its transmission line span pilot in 2024 to evaluate inspection methods for assessing span conductor integrity. PG&E expanded the scope of its pilot in 2025 to further refine the inspection method, enhance its efficiency, and strengthen the overall inspection process. PG&E stated that the goal of the pilot is to 1) capture high resolution imagery of the conductor (clear to the conductor strand level) by drone to identify any anomalies, 2) try to make the inspection process more efficient (identify the number of splices in each phase of the conductor, splice type, and their location more accurately), 3) enhance the entire inspection process so that it can be scaled into a program, and 4) test the helicopter inspection method if time and funds allow.

The 2025 program covered 1,550 spans across 7 lines (approximately 180 miles). One of the goals of the pilot was to develop a pilot shot sheet, where strand-level images are to be collected in approximately 50-foot intervals from both sides of the line from the same direction, with extra shots needed for different pole configurations. This span pilot is also assisting in the development of an inspection check list with detailed questions on



transmission line assets and conditions.

PG&E's expectations for the desktop inspection of this pilot were to focus on inspecting the components of the span, such as conductors, spacers, dampers, tie wires, jumpers, connectors, splices, marker balls, shield wires, and optical ground wire. PG&E notes that while the focus of this program is on capturing span imagery, certain components of the transmission structures (inspected separately as part of regular Wildfire Mitigation Plan (WMP) drone inspections) may also be captured. PG&E states that should a span inspection identify anything on a structure image that can cause immediate public safety issues, equipment damage, or potential to impact operations, they are required to immediately report such issues. If span maintenance conditions are identified, inspectors will be able to create maintenance tags, which will have their own supplementary designation to differentiate span inspection tags from WMP tags.

The 2025 pilot identified 85 new tags (7 priority A, 63 E, and 15 F) for conditions not previously identified in prior WMP inspections, with 6 of the 7 A tags identified mid-span. The pilot was also much better at identifying splices, with 2,044 identified in the pilot versus 774 having previously been identified with regular drone inspections over the same spans. PG&E is continuing to evaluate its pilot results, and the ISM will report on any decision to operationalize this program in its next ISM Report.

RISK MONITORING AND ASSESSMENT

PG&E continues to refine and expand risk assessment activities across its service territory in addition to its periodic updating of its core distribution and transmission wildfire risk models that were detailed in ISM Previous Reports. During the current ISM reporting period, the ISM observed PG&E's assessment activities in relation to its system-wide blackout risk along with services being provided to select critical customers. PG&E is also developing and refining new models to address its urban conflagration risk. In addition to reporting on these developments, the ISM has also been tracking the development and utilization of a refreshed group of Key Risk Indicators (KRI). These operational and cross cutting KRIs are used by PG&E's Risk and Compliance Committee (RCC) to track operational and environmental risk trends.

System Wide Blackout Risk

Several large-scale, international blackout events occurred in 2025:

- *Iberian Peninsula:* This April 2025 system-wide blackout impacted 50 to 60 million residents of Spain, Portugal, Andorra and parts of southern France, resulting in the deaths of eight people, with maximum duration of under 24 hours.
- *Chile:* This 2025 system-wide black-out impacted 98% of Chile's 20 million people, with maximum duration of 24 hours, claiming the lives of three medically dependent people.

PG&E introduced system-wide blackout as a high risk-ranked item (5th) in its 2024 Risk Assessment and Mitigation Phase (RAMP) filing with the CPUC, and PG&E estimates the economic impact of a one-day blackout of its service territory at approximately \$2 to \$5 billion. In its review of the two 2025 blackouts, PG&E notes that these outages highlighted a lack of coordinated interdependency risk assessment among utilities and system operators. As part of



its internal review, PG&E noted that its own risk assessment and compliance activities are siloed by asset group, with each focused-on meeting more than 30 standards, order and alerts from the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), the California Independent System Operator (CAISO), etc. independently, with no central authority evaluating cross-asset or system-wide interdependencies. In total, PG&E determined that there were approximately 250 areas of interdependency risk that need investigations.

Following its initial evaluation, PG&E determined that a system-wide review is needed, and that 1) this assessment should initiate a holistic, joint, system-wide risk review across asset groups (e.g., System Operations, Transmission Planning, Power Generation, Compliance), 2) external parties (e.g., CAISO, third-party Inverter-Based Resources (IBRs),¹⁹ and large-load customers) should be included when proposing controls and standards, and 3) the study should address essential reliability services like voltage and frequency support, reliability operations and operations planning for bulk power system.

PG&E's workplan, which it intends to start in 2026, includes:

- *Area coordination studies:* Perform approximately 50 interdependency studies per year over a 5-year cycle to cover the entire 250 areas of interdependency risk in order to ensure protective devices are properly coordinated, enable fast fault tripping for quick clearance and system stability, and determine how to operate under a range of contingencies.
- *System compliance assessment:* Assess the transmission system against the 30+ NERC, FERC, and CAISO standards, orders, and guidance (e.g., voltage regulation, ride-through, active power frequency control). These tests will demonstrate how the system performs under adverse conditions (e.g., black start, under-frequency, 800 MW+ load ramp or shed).
- *Restoring compliance:* Design and begin implementing mitigations for any identified weaknesses that could cause cascading outages.

In addition to this work, PG&E also identified several immediate actions and controls that it can implement. These include 1) deploying real time 500 kV screens to monitor voltage magnitude, phase angle difference, and oscillation detection at key substations, 2) identify projects to implement near term oscillation detection tools for engineering, 3) review and adopt recommendations for synchronized measurement technology, 4) expand industry coordination and benchmarking, 5) strengthen interconnection oversight by reviewing existing contracts with IBRs, monitoring interconnections for adherence to standards, and defining potential system dispatch guidelines for mitigation actions.

PG&E states that if recommended risk investments are not made, then it may be required to limit future additions of IBR resources and large loads to reduce catastrophic system risk, increase preventative maintenance for high impact infrastructure customers, and expand its

¹⁹ IBRs are power-producing units - principally solar photovoltaic, wind, and battery storage - that use power electronics to convert direct current (DC) into alternating current (AC) for the grid. Unlike traditional synchronous generators, IBRs lack inherent inertia, creating grid stability and reliability challenges.



equipment monitoring programs.

Critical Customer Risk Assessments

PG&E is also in the process of completing risk and mitigation evaluations of its key, high impact critical infrastructure customers. PG&E began the exercise by first identifying critical customer sectors that it services through Department of Homeland Security criteria. These include public safety partners (such as customers in the communication, emergency services, energy, healthcare, water and wastewater sectors) along with customers in other high impact critical sectors (such as chemical, transportation, and commercial facilities). PG&E then generated a list of its top 60 critical customers across these sectors which would receive individual risk assessments. PG&E completed the first 40 of these assessments by the end of 2025 and completed the remaining 20 by April 2026.

Each individual assessment identifies critical societal capabilities and supporting infrastructure to evaluate the risk of losing service to these customers (probability and consequence). Each risk assessment identified high, medium and low risk among these five assessment categories:

- Resilience: evaluation of electric system robustness, redundancy, and risk.
- Reliability: outage risk reduction via maintenance and capital improvement.
- Power quality: power quality and voltage transient issues.
- Investment: past/planned investments and upgrades.
- Performance: existing performance/risk and gap analysis.

After determining risk scores for critical infrastructure, PG&E then establishes immediate, mid-term, and long-term actions to de-risk the service to these sites.

Following a transformer fire in a UK National Grid substation in March 2025 that led to the closing of London Heathrow airport for over 24 hours, PG&E began its investigations with risk assessments at multiple Bay-area airports. The ISM observed the results of these assessments, and while it is not appropriate to share specific findings in this public ISM Report 8 due to security concerns, the ISM can report that each airport assessment generated specific listings of immediate (<6 months), mid-term (6 months – 2 years) and long-term (2+ year) recommended actions. Current practices at each airport were also compared against best practices at other large airports for each of the 5 assessed areas.

PG&E stated that the prioritization of the 60 assessments was driven in part to get projects into the 2027 workplan and to align recommended system improvements with other workstreams. While not all assessments completed so far generated immediate or mid-term capital needs, for those that did, PG&E indicated that it needs to balance funding priority for reliability (which CAISO is more supportive of) versus funding for societal impact (such as to improve service to individual customers such as an airport or sports stadium).

Urban Conflagration Risk Modeling

PG&E is in the process of generating risk models that can help identify where ignitions started by PG&E assets may contribute to urban conflagration (UC) events, where large-scale fires can spread rapidly through urban areas, fueled by structures as well as vegetation. PG&E notes that



UC is a multi-faceted issue, and as PG&E continues to address how UC can be attributed to ignitions started by PG&E assets, it can then expand to looking at which communities may be vulnerable to UC, as well as UCs starting and propagating as a structure-to-structure fire. PG&E states that its initial goal is to identify the relative potential of an ignition starting at a PG&E asset location to cause urban conflagration and to determine a ranking of these assets.

In the initial iteration of the UC model, PG&E is attributing UC risk to its assets by first conducting fire spread simulations from a location. It then identifies low probability, high risk outcomes factoring in items such as structure density, fire size footprint, flame length, and rate of spread. It then extends the subset of these worst outcome simulations into the wilderness-urban interface (WUI) using heuristics consistent with the reach of embers, after which it combines flame length and rate of spread into a worst outcome fire behavior metric to determine potential wildfire intensity. These factors are calibrated using the Hauling chart, which firefighters rely on to determine their initial attack strategy based on the fire behavior. PG&E then sums distributed outcomes weighted by building density for the potential of an ignition location to cause UC, and aggregates these for circuit level conflagration metrics.

PG&E states that while such a UC metric is the most comprehensive approach to model the risk of fires spreading into the WUI, flame length (a measure of fuels, like trees and shrubs, that generate high intensity fires) and rate of spread (a measure of fuels, like dry grasses, that generate fast moving fires) on their own could also be taken into consideration. PG&E notes it can see the potential for UC on each circuit across its service territory, and that moving forward it plans on building maps that provide UC potential, flame length and rate of spread into one view.

As its next steps, PG&E plans to partner with its fire spread modeling 3rd party provider to develop a product which can be incorporated into PG&E's Wildfire Consequence model. PG&E also intends to collaborate with academia and other CA utilities, as well as analyze other vendor conflagration products to understand additional aspects that influence conflagration scenarios. In the short term, PG&E states that it intends to leverage insights from its UC potential modeling to support immediate mitigation work, such as system inspection patrols and pole clearing. In the longer term, such insights will be used to augment PG&E's consequence modeling with structure-driven fire considerations.²⁰

Key Risk Indicators

PG&E's RCC uses a collection of operational and cross-cutting KRIs to track operational and environmental risk trends.²¹ These KRIs are tracked in PG&E's Centralized Metrics Repository

²⁰ PG&E states that its 2025 internal prototype is being used to explore the methodological considerations of modeling wildfire propagation into developed areas, rather than to directly inform operational mitigation decisions. PG&E also states that it plans on building on its foundational work in 2026, validating wildfire simulation outputs produced by Technosylva that incorporate urban conflagration behavior, and integrating those simulations into the next version of its Wildfire Consequence Model (WFC v5). PG&E notes that WFC v5 is currently scheduled for deployment and internal approval by the end of Q2 2027.

²¹ Cross-cutting factors can make other risk events more likely to occur or more consequential when they do occur, and create new risks across PG&E's assets, operations and services.



system and are reported each month in RCC meeting materials. Starting at the beginning of 2024, PG&E began a KRI-refresh process. Prior to that time, PG&E noted an abundance of lagging indicators among its previously existing KRIs that did not provide actionable and proactive information. PG&E also noted that certain KRI's were not representative and comprehensive of the risks they were meant to track. The RCC indicated that it preferred KRI thresholds reflective of accepted risk tolerances (e.g., setting of certain KRI levels that would trigger enhanced actions) rather than treating the KRIs as performance indicators.

As part of its KRI-refresh, the RCC required that each new KRI meet certain risk coverage criteria (covering at a minimum the top 80% of actionable risk drivers for each functional area), as well as meeting certain relevancy, actionability and measurability criteria.²² The ISM began tracking these KRIs at the beginning of its engagement, and observed the presentation and discussion surrounding several new KRI's brought to the RCC for approval. In many instances, the KRI development team presented several alternative KRIs to the committee for consideration and provided its reasons for recommending the retirement of the old, ineligible KRI's, as well as highlighting their preferred replacements.

The RCC currently tracks 22 KRIs covering areas such as 3rd party caused outages, electric distribution dig-in rate, failure of electric distribution and transmission overhead, underground, and substation assets, public contact with intact energized electrical equipment, transmission system-wide blackout, emergency preparedness and response, and wildfire (i.e., tracking weather normalized CPUC reportable ignitions in HFRA). PG&E currently includes KRIs for five climate change related factors, including 1) major storms and high precipitation events, 2) drought, 3) flooding, 4) high temperatures, and 5) sea level rise/coastal flooding. Many of the selected KRI targets were based on 3- or 5-year historical averages, plus or minus a selected number of standard deviations appropriate to set a level where, if triggered, would indicate that PG&E needed additional focus or effort to address an emerging condition. See APPENDIX: KRI SUMMARY TABLE at the end of the report for a description of each of the KRIs.

While PG&E cannot influence the frequency of occurrence of climate-driven natural hazard events, it states that its Climate Resilience team conducts and coordinates a suite of measures designed to mitigate climate-driven physical risk by integrating climate data into key processes and assessing climate vulnerability via the CPUC-mandated Climate Adaptation and Vulnerability Assessment process.

Since the issuance of the refreshed KRIs, the ISM noted a small number of KRIs that temporarily exceeded their thresholds, and questioned PG&E on reactive actions taken or the circumstances behind the temporary exceedance. In one instance, the KRI was breached shortly after its approval for use in December 2024 and continues to remain above the KRI threshold since then. This KRI was for Just-In-Time Distribution Asset Findings (Volume). This KRI measures the total volume of all equipment failures (just-in-time priority A and X maintenance tags from inspections, and A tags created for in-service failures) in the preceding

²² With regards to a KRI achieving 80% of risk coverage, the metric is based on percentage of actionable risk, and excludes the impact of cross cutting risks (seismic, climate, physical attack), human performance and other PG&E assets or processes.



twelve months, and is seen as providing a trend of overall distribution system health.²³

PG&E stated that the breach of this KRI so soon after its establishment was not indicative of worsening asset health, but was instead due to changes in inspection methodology, a shifting of inspections in HFTD from predominantly ground-based to aerial (with higher find rates as a result of new assets views), and the introduction of the new priority X maintenance tags which were being issued at a greater than forecasted rate. PG&E states that following its analysis of the KRI threshold breach, it continues to discuss options for amending the existing KRI threshold, as the multitude of changes warrant an improved threshold methodology.

DISTRIBUTION INSPECTIONS AND MAINTENANCE

Distribution inspections are PG&E's mechanism for identifying overhead equipment issues and translating them into notifications. This section examines changes to the 2025 to 2026 overhead job aid used by PG&E's distribution inspectors, PG&E's 2025 distribution inspection findings, and the ISM's independent field observations of open B tags, overdue E tags, and cancelled notifications.

Changes to the Overhead Job Aid

PG&E uses a job aid to help define how inspectors should inspect overhead conditions and when they must write Electric Corrective (EC) notifications with assigned A/X/B/E/F priorities. The 2026 update to the Job Aid incorporates two major guidance changes, detailed below, along with several examples of tag priority modifications and clarified descriptions including updated photographs and new examples.

Major Guidance Changes

The 2025 job aid allowed down guys to be no more than three feet from taut before triggering an EC notification. In the 2026 update, this guidance became two inches from taut based on additional testing.

Additionally, in the 2025 job aid, a shipping lock present on an in-service transformer was considered a "non-compelling abnormal condition" and did not require an EC Notification. In 2026, this condition has been updated and classified as an X Tag condition. Shipping locks disable the transformer's internal fault device (IFD) and prevent venting. When left on an energized transformer, the IFD cannot function as intended, creating a potential failure.

Tag Priority Modifications and New Examples

In the 2026 Job Aid, PG&E updated the assigned priorities for several existing examples and added a few new examples to the job aid. Of the five priority changes, three represent escalations for the minimum notification: improperly installed ties moved from E to A, poles split at the communications level from B to X, and incorrectly installed chance clamps from F

²³ This metric excludes A/X tags and asset failures associated with vegetation (dealt with in a separate vegetation-based finding in this KRI group), third-parties, animal contact, lightning, and fire. This KRI is also supplemented with another similar KRI which tracks the percentage of Just-in-time inspection discoveries versus assets which have failed in the field, to track the effectiveness of the inspection program.



to E. The minimum assignment for broken tie wires went from A to X and healthy green trees in proximity to the conductor were removed from the EC notification requirement entirely. The new examples are predominantly E-tag conditions in HFTD, with the most operationally significant additions relating to liquid-filled fuse and cutout conditions addressed further in the Year-over-year B Tag Trends section below.

PG&E’s 2025 Distribution Inspection Findings

PG&E-reported 2025 distribution inspection results including find rates, year-over-year B-tag variance by Facility-Damage-Action (FDA), and top-volume FDAs by priority.

Find Rates by Priority

In 2025, PG&E completed 266,810 aerial HFTD inspections which was 23 percent more than the 216,913 completed in 2024. HFTD ground inspections totaled 10,133 structures and non-HFTD ground inspections totaled 293,387 structures. Table 5 summarizes notification rates by priority and HFTD.

Table 5: 2025 Distribution Inspection Find Rates

Priority Tag	Aerial – HFTD (266,810 insp.)	Ground – HFTD (10,133 insp.)	Ground – Non-HFTD (293,387 insp.)	Year-Over-Year Find Rate Review ²⁴
A	0.2% (621)	0.1% (12)	0.5% (1,613)	Consistent with prior year
X	0.8% (2,134)	0.3% (31)	1.4% (4,051)	First full-year baseline since Sep. 2024 adoption
B	1.3% (3,360)	0.8% (77)	1.4% (4,020)	Down from 2.21% aerial in 2024; may reflect LFF reclassification
E	22.3% (59,549)	7.1% (716)	10.6% (31,107)	Roughly stable year-over-year
F	0.2% (469)	1.1% (112)	3.9% (11,534)	Down from 0.43% aerial in 2024
Total	24.8% (66,133)	9.4% (948)	17.8% (52,325)	

Aerial HFTD inspections continued to produce the highest concentration of findings: one in four structures inspected carried at least one tagged condition. E-tag conditions drove the bulk of this volume at 22.3 percent, roughly stable from the 21.3 percent reported in 2024. A-tag rates remained consistent with prior years.

The X-tag aerial HFTD find rate of 0.8 percent, producing 2,134 findings, represents the first full-year baseline since X-tag full scale adoption in September 2024.²⁵ The 2024 partial-year rate of 0.4 percent covered only the final months of the year and is not directly comparable.

Year-over-year B Tag Trends

Table 6 shows the most significant year-over-year movements in HFTD aerial B-tag find rates.

²⁴ See Table 5, Page 40 in ISM Report 6

²⁵ According to PG&E, X-tags were fully rolled out on March 24, 2024 however, “find rates from September 2024 – December 2024 were more predictive of the X-tag find rate in 2025 than the entire year of 2024.”



Table 6: Priority B HFTD Aerial Find Rate Changes by FDA (2024 vs. 2025)

FDA	2024	2025	Delta
YTD Inspections: 216,913 (2024) → 266,810 (2025) Net: +49,897 structures			
<i>Cutout Broken/Damaged Replace</i>	0.77%	0.09%	-0.68%
<i>Fuse Broken/Damaged Replace</i>	0.76%	0.09%	-0.68%
<i>Hardware/Framing Loose Adjust</i>	0.30%	0.10%	-0.20%
<i>Crossarm Broken/Damaged Replace</i>	0.32%	0.20%	-0.12%
<i>Pole Decayed/Rotten Replace</i>	0.26%	0.12%	-0.14%
<i>Insulator Broken/Damaged Replace</i>	0.15%	0.17%	+0.01%
<i>Tie Wire Loose Replace</i>	0.15%	0.17%	+0.02%
<i>Pole Woodpecker Damage Replace</i>	0.12%	0.04%	-0.09%

The most pronounced B-tag decline involves Cutout Broken/Damaged Replace and Fuse Broken/Damaged Replace, which each fell from approximately 0.76–0.77 percent to 0.09 percent, an 89 percent reduction. These two FDAs declined in tandem because PG&E's job aid requires inspectors to document the low liquid fuse condition using both FDAs. Since replacing a fuse typically requires replacing the cutout as well, both are recorded together on the same notification. According to PG&E, both find rates reflect a similar decline primarily attributed to a 2024 job aid revision that reclassified liquid-filled fuse (LFF) conditions from Priority B to Priority E, following a RCC determination that the risk of deferred replacement was comparable to the risk introduced by replacement itself, given that cutout replacement frequently results in crossarm and pole replacement. PG&E engaged a third-party contractor to conduct a comprehensive LFF assessment, with results anticipated to be presented in 2026 to inform final guidance on liquid-level thresholds and replacement priority.

Top FDAs by Priority

Table 7 shows the leading FDAs by tag count for each priority in the aerial inspection program. A and X-tag data spans HFTD and Non-HFTD; B and E data covers HFTD aerial only.

Table 7: 2025 YTD Top Aerial FDAs by Priority

FDA	Priority	Count	Cumulative Share
Transformer Leaks/Seeps/Weeps Replace	A	139	20%
Transformer Broken/Damaged Replace	A	105	34%
Conductor Broken/Damaged Repair	A	103	49%
Conductor Broken/Damaged Repair	X	551	24%
Transformer Broken/Damaged Repair	X	407	42%
Tie Wire Broken/Damaged Replace	X	266	53%
Conductor Broken/Damaged Repair	B	582	9%
Crossarm Broken/Damaged Replace	B	525	16%
Tie Wire Loose Replace	B	455	23%
Conductor Broken/Damaged Repair	E	7,566	8%



Cutout Broken/Damaged Replace	E	6,898	15%
Fuse Broken/Damaged Replace	E	6,834	22%
Insulator Broken/Damaged Replace	E	5,439	27%
Pole Decayed/Rotten Replace	E	5,350	32%

Transformer conditions dominated A-tag aerial findings in 2025, a pattern first documented in Report 6, which noted that leaking transformers were the highest A-tag aerial find in 2024. The 2025 data reinforce that observation: Transformer Leaks/Seeps/Weeps Replace (139 findings) and Transformer Broken/Damaged Replace (105 findings) together accounted for 34 percent of all aerial A-tag volume, with Conductor Broken/Damaged Repair ranking third at 103 findings. Unlike substation equipment, PG&E’s overhead transformers do not receive diagnostic testing such as dissolved gas analysis, power factor testing, or turns ratio testing. Condition assessment for overhead transformers relies on external visual inspection, supplemented to some extent by load analysis using Smart Meter data and age-based tracking. As a result, internal degradation is not detected until it presents as a visible external condition, and the A-tag finding rate for transformer conditions reflects the point at which deterioration becomes externally observable rather than earlier identification through proactive diagnostic monitoring.

Conductor conditions led across all other priority tiers. Conductor Broken/Damaged Repair was the top FDA for X-tags (551 findings), B-tags (582), and E-tags (7,566) in the HFTD aerial program. This is consistent with the information presented in ISM Report 6, which documented that conductor failures represent approximately 10 percent of equipment-related outages, averaging roughly 230 outages per year in HFTD since 2019, and accounting for over 30 percent of equipment failure-caused CPUC reportable ignitions, the highest of any equipment category. ISM Report 6 also noted that proactive deteriorated conductor replacement had been running at roughly half the rate needed to sustain the asset base. The 2025 FDA data show that despite ongoing inspection and remediation activity, conductor conditions remain the dominant finding across every priority tier in the HFTD aerial program.

2025 EC Tag Cancellations

As mentioned in ISM Report 7, three programs contributed to tag re-evaluation and cancellation in 2025: (1) CIRT, which performs field-triggered desktop reviews and manages inspection escalation; (2) the PACT, which performs systematic desktop reviews of open tags for work readiness and asset strategy; and (3) the EC Work Readiness Tag Cleanup team (WRTC), which oversees distribution EC maintenance tag reviews and is responsible for ad-hoc distribution EC backlog reviews such as duplicate tag reviews. Collectively, the three teams reviewed 268,702 distribution tags in 2025 and cancelled 37,309 tags, representing an overall cancellation rate of 14%. Table 8 shows the number of tags reviewed in 2025 along with the number of tags cancelled by program.



Table 8: 2025 EC Maintenance Tag Review

2025 EC Maintenance Tag Review	2025 Review	2025 Cancellation	Cancel Rate %
Centralized Inspection Review Team (CIRT)	53,968	5,383	10%
Package Consensus Review Team (PACT)	178,551	29,365	16%
EC Work Readiness Tag Cleanup (WRTC)	36,183	2,561	7%
Grand Total	268,702	37,309	14%

PACT was the largest program by both volume of tags reviewed and number of tags cancelled, reviewing 178,551 tags and cancelling 29,365 at a 16% rate.²⁶ PG&E reported that the 2025 cancelled EC notifications from PACT saved approximately \$233 million in ‘soft’ avoided costs attributable to only tag cancellations in HFTD/HFRA. PG&E characterized these as soft savings because the construction or repair work associated with the cancelled tag could be actualized outside the current-year work plan. CIRT reviewed 53,968 tags and cancelled 5,383 at a rate of 10% whereas WRTC reviewed 36,183 tags and cancelled 2,561 at a rate of 7%. Table 9 shows the full-year EC tag cancellation breakdown by cancel reason and program.

Table 9: 2025 Tag Cancellations by Reason and Program (PACT/CIRT/WRTC)

2025 Cancel Reason	Total	% of Total	Priority Tag				Program		
			B	E	F	H	PACT	CIRT	WRTC
No Compelling/Regulator Condition Exist	30,656	82.2%	11	18,210	11,901	534	26,122	4,469	65
All Found Completed/Resolved on Arrival	2,985	8.0%	9	1,479	1,371	126	2,497	456	32
Duplicate EC for Same Location	592	1.6%	7	453	68	64	284	129	179
Completed under another Program	3,002	8.0%	11	988	209	1,794	424	306	2,272
Converted to another Notif-Type	54	0.1%	2	37	10	5	28	14	12
Created in Error (Desk Cancellation)	20	0.1%	1	13	3	3	10	9	1
Total	37,309	100%	41	21,180	13,562	2,526	29,365	5,383	2,561

Table 10 shows the EC tag cancellation breakdown by notification year, priority and HFTD designation.

Table 10: 2025 Tag Cancellations by Year and Priority by HFTD

Notification Year	Total	% of Total	HFTD				Non-HFTD			
			B	E	F	H	B	E	F	H
2014	24	0.1%	-	2	10	1	-	2	9	-
2015	365	1.0%	-	5	74	11	1	7	262	5
2016	315	0.8%	-	12	158	8	-	1	130	6
2017	283	0.8%	-	12	201	11	-	-	56	3
2018	133	0.4%	-	11	83	5	-	2	31	1
2019	2,529	6.8%	5	1,235	223	242	-	285	507	32
2020	3,690	9.9%	-	687	681	116	3	761	1,372	70
2021	3,772	10.1%	2	1,748	1,198	198	-	369	219	38
2022	9,426	25.3%	5	5,156	2,415	324	1	1,239	198	88
2023	11,274	30.2%	4	5,537	3,777	673	1	1,001	248	33
2024	5,002	13.4%	11	2,430	1,578	626	3	229	118	7
2025	496	1.3%	1	432	10	27	4	17	4	1

²⁶ PG&E has reported that PACT and CIRT merged in December 2025 under a single expanded CIRT team.



ISM Desktop Review of PACT Cancellations

During the current ISM reporting period, the ISM conducted a desktop review of higher-priority cancellations from PACT's initial dataset, which was provided to the ISM during the current reporting period. The ISM's review focused on the one A-tag cancellation and all 32 B-tag cancellations from this preliminary dataset.²⁷ The review assessed whether the cancellation determination was consistent with the available drone photos and SAP records, whether the assigned cancel reason accurately reflected the basis for cancellation, and whether the underlying condition appeared to be physically resolved. While the ISM does not take exception to the cancellation decision for 30 of the 33 tag cancellations, the review identified several cases where the reason for cancellation differed from what the desktop review found (i.e. the reason provided by PG&E indicated “No compelling or regulatory condition exists” but the reason found from the ISM’s desktop review found the reason to be “Duplicate notification exists for same issue and location”). Additionally, in a handful of cases, the available drone imagery and SAP records did not fully document work completion.²⁸ A summary of the ISM’s desktop review is provided in Table 11.

Table 11: Summary of ISM's Desktop Review

PG&E's Reason for Cancellation	ISM's Desktop Review Findings	Count
<i>All work found completed/resolved upon arrival in the field</i>	Consistent with PG&E's Reason	5
	<i>Additional Information Requested</i>	1
<i>Duplicate notification exists for same issue and location</i>	Consistent with PG&E's Reason	2
	<i>Additional Information Requested</i>	1
<i>No compelling or regulatory condition exists</i>	Consistent with PG&E's Reason	8
	Duplicate Notification Appears to Exist	3
	All Work Appears to be Completed	2
	Open: Moved to F Tag	1
<i>Notification completed prior to cancel recommendation being processed</i>	Consistent with PG&E's Reason	4
	<i>Additional Information Requested</i>	1
<i>Work belongs to or is being completed by another program</i>	Consistent with PG&E's Reason	5

The ISM brought three cases requiring additional information to PG&E's attention highlighted in Table 11. In the first, PG&E cancelled the tag under "All Work Found Completed" but the ISM found no photographs or supporting documentation within SAP or Sherlock to verify the pole replacement. Following the ISM's inquiry, PG&E was unable to identify information supporting

²⁷ Following the ISM's desktop review, PG&E provided a superseding dataset reflecting the combined cancellation activity of all three review programs (CIRT, PACT, and WRTC) for the full 2025 reporting period. The updated dataset reflects a PACT cancellation total of 29,365, compared to 32,690 in the initial dataset. The ISM's desktop review findings presented in this section are based on the initial dataset which targeted all A-tag and B-tag cancellations.

²⁸ Standard practice for utility maintenance documentation includes a record of the original identified condition, what crews observed upon arrival at the asset, the work performed including parts replaced and tasks completed, and the as-left condition of the asset supported by photographs. This documentation standard is common across the utility industry and allows for independent verification that a reported condition was physically resolved and that the asset was returned to a compliant state following repair.



the cancellation and dispatched a crew to the field, which confirmed the pole condition still exists, and the tag should remain open as a B-tag requiring completion. In the second case, PG&E cancelled the tag as a duplicate and a June 2025 aerial inspection showed the pole not yet replaced; PG&E confirmed that it merged the conditions with another notification, the pole was replaced on December 11, 2025. PG&E field-verified this completed work. In the third case, the ISM found no specific documentation confirming the installation of a cotter key driving the B-tag priority; PG&E clarified that the crew completed all hardware work on April 29, 2025, including the cotter key, and the asset was built as designed. The ISM considers the second and third cases resolved. The first case resulted in the re-opening of the B-tag.

ISM Field Observations

During the current ISM reporting period, the ISM conducted three distinct tracks of field review activity: (1) review of 30 cancelled notifications on pole tags (with particular attention to woodpecker-damage cancellations); (2) ongoing B-tag field reviews continuing from the program initiated in mid-2025 detailed in ISM Report 7; and (3) field review of approximately 400 open E-tag structures, of which 19 were submitted to PG&E for additional review. The findings from these activities are summarized below.

ISM Review of Cancelled Notifications

In addition to the desktop reviews detailed above, the ISM conducted field reviews of poles where PG&E cancelled existing EC notifications, with a particular focus on cancellations involving woodpecker damage. Woodpecker damage was selected as the primary focus of this field review because it is a condition category that has been subject to successive job aid revisions and because the determination of whether woodpecker damage warrants an EC notification should be visible both from the ground as well as from aerial footage.

The ISM reviewed 30 cancelled pole notifications in the field. In each case, the ISM assessed whether the observed field condition was consistent with the cancellation determination. The ISM found consistency with all 30 cancellations. In each case, the hole patterns observed were consistent with the job aid's threshold for conditions that do not require an EC notification under their most recent job aid criteria.

ISM B-Tag Review

As documented in ISM Report 7, the ISM performed field reviews of open HFTD B tags in June 2025. Through July 31, 2025, the ISM completed 102 field reviews, identifying three tags submitted for additional review to PG&E, two past-due and one current. PG&E confirmed completion of repairs for all three referred tags. As previously reported in ISM Report 7, PG&E eliminated its B tag backlog, which has been a focus of ISM monitoring since ISM Report 4.

During the current ISM reporting period, the ISM continued performing field reviews on open B tags and did not identify any open B tags that require immediate attention or escalation. In total, the ISM field reviewed 160 B tags during the current ISM reporting period. PG&E reported year-end 2025 B-tag on-time completion of 81 percent, an improvement from 48 percent in 2024, and zero past-due B-tags as of December 31, 2025.



ISM E-Tag Field Review

During the current ISM reporting period, the ISM conducted a targeted review of open E-tags, initially focusing on notifications created in 2022 or earlier. As the field review progressed, the ISM expanded its scope to include all open E-tags in order to assess whether the findings from older notifications reflected the aging and natural condition deterioration, or whether they were indicative of misclassification at the time of the original inspection. In total, the ISM reviewed 400 open E-tag structures during the current ISM reporting period which consisted of approximately 70% open pole notifications and 30% other open notifications including, but not limited to, conductors, crossarms, and connectors.

The distribution of reviewed structures by original notification year is shown in Table 12 below, along with the open E-tag population in HFTD as of December 31, 2025 and the subset of structures the ISM submitted to PG&E for additional review. The review was intentionally weighted toward older notifications, with the largest concentrations among poles originally tagged in 2023 and earlier. Of the 400 structures reviewed, the ISM identified 19 poles where the observed field condition appeared to be past the E-tag level notification and were submitted to PG&E for additional review.

Table 12: Summary of Open E Tags, ISM Field Reviews, and ISM Findings

<=2018	2019	2020	2021	2022	2023	2024-2025
PG&E Open E Tag Notifications as of December 31, 2025 (HFTD)						
1,886	15,462	6,301	10,744	16,237	36,707	115,166
ISM Field Reviews (400 total)						
3	62	32	42	78	106	27
Submitted to PG&E for Additional Review (19 total)						
0	8	1	6	3	1	0
0%	13%	3%	14%	4%	1%	0%

The referral rate varied significantly by notification vintage. Poles with original notification dates in 2019 and 2021 had the highest referral rates relative to the number reviewed. The ISM submitted eight of 62 reviewed with 2019-vintage notifications (13%) and six of 42 reviewed with 2021-vintage notifications (14%) for additional review. By contrast, the ISM did not refer any poles from the 2024–2025 notification vintage and only one of 106 from the 2023-vintage.

PG&E provided responses for the 19 referred poles as shown in Table 13 and Table 14 below.

Table 13: Summary of PG&E’s Responses to Poles Submitted for Additional Review

PG&E Response	Count	Notes
<i>Escalated to X-Tag</i>	4	Pole conditions with notification dates between 2019–2021
<i>Escalated to B-Tag</i>	1	Pole condition with notification date of 2019
<i>Listed for work in the system to be replaced</i>	14	Pole conditions with notification dates between 2019-2023
TOTAL	5/400	1.25% of poles escalated



Table 14: Summary of FDAs for Poles Submitted for Additional Review



FDA	Esc. to X-Tag	Esc. to B-Tag	“Listed for work”
Pole, Broken/Damaged , Replace	2	1	3
Pole, Decayed/Rotten , Replace	2	0	3
Pole, Woodpecker Damage , Replace	0	0	1

Of the poles submitted for re-review to PG&E, five poles were escalated with four to an X notification requiring expedited repair, and one to a B notification. All five of these poles were originally identified by PG&E between 2019 and 2021. For 14 of the poles submitted, PG&E indicated “[a]t this time, none of the notifications have been canceled and all are currently still listed for work in the system to be replaced”.

ISM Observations of the Limitations of Aerial Inspections

A recurring observation in the ISM’s distribution field program is that aerial photography, while providing coverage of pole-top and mid-span conditions, does not reliably capture all condition categories material to safety and compliance. During the current ISM reporting period, the ISM identified four conditions where available aerial imagery was insufficient to make a definitive assessment, and where ISM ground inspections identified conditions that the aerial record did not detect. Table 15 summarizes each category.

Table 15: Aerial vs Ground Observations

ISM Field Observation	PG&E’s Best Available Aerial Photo of Same Asset
<i>Exposed ground below 8 ft</i>	
	



Down guy grounded above insulator



Strain / abrasion on service conductor



Pole steps below 8'6"



ISM Reports 5 and 6 each documented this aerial limitation issue with ISM Report 5 noting that drones are more challenged at capturing tree connections, anchors, and ground-level issues and ISM Report 6 calling out the high number of finds by 'exposed grounds' and 'down guys above insulator grounded'. Additionally, ISM Report 5 discussed PG&E's response of adding



criteria to the required shot sheet. In current ISM reporting period discussions with PG&E, PG&E continued to discuss the addition of a photo to the shot sheet. In addition, PG&E stated that it plans on running their own pilot this year with a double-blind test on 20,000 poles whereby they will conduct a ground and an aerial inspection on the exact same poles looking for A and B conditions. PG&E is having a third party compare the results found in this pilot. After PG&E and the third party review the results of the pilot, PG&E will then determine if aerial inspections will qualify for General Order 165 (GO 165) inspections.

SUBSTATION ASSET MANAGEMENT AND MAINTENANCE

Substation equipment and grid control failures have been associated with significant customer outages and disruptions to critical services in recent periods, both domestically and internationally.²⁹ These types of events are exacerbated by a broader national challenge: utilities across the United States are increasingly reliant on aging assets, many operating beyond their recommended service life, with equipment failures and reliability issues as a growing consequence.³⁰

During the current ISM reporting period, the ISM initiated a review of PG&E's substation infrastructure assets, covering both transmission substation (TSBSN) and distribution substation (DSBSN) operations. The ISM reviewed several regulatory and internal assessments on PG&E's substation programs, including the CAISO 2025 Annual Maintenance Review (AMR) Report; PG&E's Operational Risk Validation (ORV) Substation Maintenance Advisory; and PG&E's 2024 Risk Spending Accountability Report (RSAR) and the CPUC's review of that filing. The ISM's monitoring activities also included meetings with PG&E's Substation Operations, Asset Management, and Engineering personnel, and field observations at select substation sites. The following subsections detail the ISM's observations related to these assessments, substation equipment age and end-of-life, proactive maintenance shortfalls and tagging, and safety practices and field conditions.

CAISO 2025 Annual Maintenance Review

CAISO conducts an AMR of Participating Transmission Owners' filed maintenance practices for transmission facilities under CAISO operational control. The 2025 AMR reviewed seven of PG&E's 923 substations, spanning in voltage class from 69 kV to 500 kV. The review identified the highest number of systemic findings related to substation maintenance practices in recent years,³¹ with four findings related to station maintenance and one related to transmission line maintenance.

²⁹ In 2025, a fire at a 275kV substation caused a loss of power to Heathrow Airport, voltage control issues triggered a widespread grid failure across Spain and Portugal, and domestically, a fire at a substation in San Francisco impacted approximately 130,000 customers, disrupting transit, traffic signals, and services.

³⁰ <https://infrastructurereportcard.org/cat-item/energy-infrastructure> and <https://sepapower.org/knowledge/the-aging-us-power-grid-navigating-toward-modernization>

³¹ Information presented to the ISM after PG&E's Electric RCC Meeting on September 25, 2025.



The station findings included

- The late completion of approximately 10% of periodic and 9% of non-periodic maintenance notifications, with late completions ranging from 8 days to 2 years past the compliance date
- Approximately 7% of periodic and triggered maintenance tasks still outstanding at the time of the review
- Significant and recurring deficiencies in battery and direct current (DC) system maintenance across multiple maintenance headquarters, indicating a systemic rather than localized issue
- An inability by PG&E field personnel to access Human-Machine Interface (HMI) terminals for Gas Insulated Substations (GIS) and Series Capacitors at all stations visited, with several standing local alarms observed that PG&E could not confirm as captured in its Computerized Maintenance Management System (CMMS).

Additionally, inaccuracies were identified in the tracking of Accumulated Critical Current (ACC) data, with five of fourteen 2024 transmission line faults either missing from or incorrectly documented in PG&E's ACC records. CAISO flagged battery system maintenance as a recurring concern in its annual reviews dating back to 2014.

In response to the 2025 AMR, PG&E identified four areas requiring improvement:³² 1) Gaps in implementation of holistic transmission and substation (T&S) asset management plan (AMP), 2) Limited asset condition monitoring and visibility, 3) Inadequate controls; past due maintenance, and 4) Adherence to the processes and procedures; noncompliant maintenance record and inadequate training. Table 16 summarizes the operational improvements and associated resource commitments proposed by PG&E in response to these findings.

Table 16: PG&E's Planned Operational Improvements by Category

<i>Operations</i>	<ul style="list-style-type: none"> • Battery replacement and maintenance • Additional full-time equivalents (FTE's) to address preventative maintenance delays, tag backlog and compliance purposes • Development of systemic training to resolve field gaps
<i>Asset Management</i>	<ul style="list-style-type: none"> • Additional FTE's to support: <ul style="list-style-type: none"> ○ Audit and procedure updates ○ Engage in strategic planning for inspection and manage equipment specific maintenance ○ Improve existing preventative maintenance to be condition-based ○ Integrate tag findings with engineering models ○ Gain a deeper understanding of equipment asset health
<i>Specialized Engineering</i>	<ul style="list-style-type: none"> • End-to-end inspection review for protection equipment • Alignment of protection maintenance standards with industry best practices • Current state review, mapping and analysis, benchmarking and gap analyses
<i>Process Improvement</i>	<ul style="list-style-type: none"> • Implementation of unspecified substation process improvements • Additional FTE for administration of Risk and Compliance programs

³² Operational improvements and resource commitments extracted from PG&E presentation materials. - PG&E's Electric RCC Meeting September 25, 2025.



ORV Substation Maintenance Advisory

In July 2025, PG&E's ORV group completed a Substation Maintenance Advisory that represents an end-to-end internal assessment of maintenance and inspection processes for both transmission and distribution substation operations. The ORV's findings were generally consistent with those of CAISO's 2025 AMR and provided a broad view of programmatic issues across risk management, asset data quality, staffing, and work planning practices. Table 17 summarizes the key findings identified in the ORV advisory.

Table 17: Summary of Key ORV Substation Maintenance Advisory Findings

Topic	ORV Finding
<i>Asset Data Integrity</i>	PG&E does not maintain a single comprehensive asset registry; critical vs. non-critical equipment cannot be reliably distinguished across SAP and GIS systems
<i>Risk Modeling</i>	Existing risk models do not adequately account for batteries and other critical minor equipment, including protective relays, potential transformers, and coupling capacitor voltage transformers
<i>Maintenance Strategy</i>	The current capital planning strategy treats minor equipment on a run-to-failure basis, which the ORV noted may not adequately reflect the critical role these assets play in substation operations
<i>Maintenance Controls</i>	High-priority maintenance notifications have been completed past their required due dates; procedural controls for timely tag completion require strengthening
<i>Bay Area Staffing</i>	Insufficient headcount in the Bay Area is a driver of quality issues and compliance risks, and the Bay Area has the highest voluntary turnover rates in the service territory
<i>Workforce & Morale</i>	Morale in Substation Operations has been on a downward trend for five to seven years, attributed to compensation differentials, supervisor turnover, and limited leadership engagement with frontline staff
<i>Funding Prioritization</i>	Wildfire mitigation, capacity, and interconnection investments have taken precedence over proactive substation asset replacement, with substation asset guardrails not currently being met
<i>Emergency Readiness</i>	Emergency response capabilities are constrained by the availability of spare equipment, with some substations operating on temporary materials two or more years after initial failures

One of the ORV's findings is the run-to-failure asset replacement treatment of protective relays, which is consistent with the ISM's observations in ISM Report 7³³ regarding PG&E's aging relay fleet. The ORV identified corrective actions across several of these findings, covering post-emergency inspection guidance, "Bay Area" staffing, notification creation authority, timely completion of high-priority maintenance tags, engineering workforce experience, and training program adequacy. The ORV's findings, taken together with those of the CAISO's 2025 AMR, informed the ISM's focus areas for this current ISM reporting period, which are detailed in the subsections that follow.

³³ Table 8, Independent Safety Monitor Status Update Report (Report 7), October 31, 2025.



Risk Spend Accountability Report – Substation Capital Spending

PG&E is required to file an annual RSAR documenting actual spending against CPUC-adopted³⁴ levels for programs related to safety, reliability, and maintenance, and provide explanations for material variances. PG&E's 2024 RSAR,³⁵ filed July 28, 2025, provides a financial dimension to the substation maintenance concerns identified by CAISO and the ORV, where emergency equipment replacements exceed adopted spending levels while proactive replacement programs were deferred.

Emergency substation equipment replacements, Major Work Category (MWC) 59, which cover equipment that has failed or been removed from service due to imminent failure risk, recorded actual capital spending of approximately \$356.9 million for 2023 and 2024, compared to an adopted level of \$175.5 million.³⁶ As described in RSAR Table 3-4, PG&E attributed this to a higher volume of emergency replacement work than forecasted in the 2023 General Rate Case and noted that continued elevated spending in this program is anticipated due to the reprioritization of other substation work,³⁷ specifically, the reallocation of funds away from the proactive replacement programs of MWC 48 and MWC 54 toward emergency replacements under MWC 59.

The increase in emergency spending was accompanied by reductions to proactive substation replacement programs (MWC 48 and MWC 54). PG&E underspent proactive substation transformer replacements by approximately 28%, and underspent proactive replacement of other substation equipment including switchgear, circuit breakers, and batteries by approximately 35%.³⁸ Proactive battery replacement was approximately \$43,000 against an adopted level of approximately \$6.9 million, a 99% underspend.³⁹ PG&E's explanation in the RSARs stated that battery replacements were rescheduled to support higher priority substation work.

Substation Asset Management

CAISO's 2025 AMR, PG&E's ORV Substation Maintenance Advisory, and PG&E's 2024 RSAR collectively identify the following related sets of concerns: maintenance activities completed late or not at all, emergency replacements taking precedent over proactive work, and capital investment in substation assets constrained by competing priorities. A common thread running through each of these assessments is the condition and age of PG&E's substation

³⁴ ISM Report 8 refers to the approved or imputed value summaries contained in the RSAR's report as "adopted".

³⁵ PG&E's 2024 RSARs report is available at <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/risk-spending-accountability-reports>

³⁶ Emergency substation equipment replacements: MWC 59. RSAR Table 3-2, row 25.

³⁷ Risk Spending Accountability Report: MWC 48, 54, and 59. RSAR Table 3-4, rows 174 (MAT 48F), 167 (MAT 48D), 164 (MAT 48C), 209 (MAT 54A), 183 (MAT 48N), 177 (MAT 48H), 159 (MAT 48A).

³⁸ Proactive substation transformer replacements: MWC 54. Proactive replacement of other substation equipment including switchgear, circuit breakers, and batteries: MWC 48. RSAR Table 3-2, rows 22 and 19, respectively.

³⁹ Proactive battery replacement: MAT 48C. RSARs Table 3-4 row 164



equipment fleet. During the current ISM reporting period, the ISM reviewed PG&E's asset age and useful life data for major substation equipment, including PG&E's internal replacement thresholds, guardrail compliance history, and forecasted replacement rates.

Condition Based and Just-In-Time Maintenance Strategies

PG&E's approach to asset management through maintenance and replacement decisions varies by equipment classification. At present, PG&E utilizes a reactive maintenance model for the replacement of minor equipment, meaning that repair or replacement decisions are initiated in response to an observed or imminent failure rather than on a predetermined schedule. For major equipment, PG&E applies both a Condition Based Maintenance (CBM) and Time-Based Maintenance (TBM) strategies.

CBM is a maintenance strategy in which replacement and repair decisions are guided by measured performance and physical condition of an asset over time. CBM uses diagnostic measurements, operational readings, and observable indicators to assess whether an asset continues to perform within established tolerances. When those tolerances are exceeded, the condition triggers a Line Corrective (LC) notification which initiates the formal repair or replacement process conducted by PG&E.⁴⁰

Within the CBM framework, PG&E applies a Just-In-Time (JIT) prioritization strategy to flag major equipment for replacement. JIT allocates available capital toward assets that exhibit the highest risk of imminent failure. Assets that have not yet exhibited clear indicators of near-term failure may be deferred for replacement even if they are operating at or beyond their established service life. While JIT can be an effective tool for directing constrained capital resources toward the most acute near-term risks, it carries inherent limitations when applied as a sustained strategy for an aging asset population. JIT in and of itself does not reduce the aging asset population, it aims to manage the risk within it and its effectiveness as a strategy assumes that the proactive replacement of aging assets has kept the broader fleet in reasonable condition. Those assets that JIT does not reach prior to failure exit the fleet through unplanned emergency replacements. Additionally, the JIT strategy introduces an inherent higher level of safety risk as equipment is operated beyond the recommended asset age and useful life and is more dependent on accurate and timely identification of imminent failure.

PG&E utilizes TBM strategies in addition to CBM strategies. According to PG&E, maintenance intervals are based on manufacturer guidelines and PG&E's experience with its equipment. The predictable nature of TBM supports planned maintenance activities, which PG&E stated can reduce downtime and the potential for outages. PG&E stated that combining TBM and CBM helps identify potential gaps in coverage when asset use is high and/or conditions fall outside industry expectations; and this combined approach also provides greater flexibility in planning maintenance activities, which can help minimize costs.

⁴⁰ ORV Substation Maintenance Advisory, July 25, 2025 (p. 84). Summary of information detailed in Substation Equipment Maintenance Requirements, TD-3322S, Rev 10, dated June 5, 2024.



Asset Age and Useful Life

Asset age refers to the length of time equipment has been in operational service, while useful (or service) life commonly refers to the estimated length of time equipment can be expected to operate reliably and perform its intended function. Asset age is one of many factors considered to determine when a substation asset should be repaired or replaced. 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.

PG&E applies age-based replacement thresholds equal to 1.5 times the estimated industry service life for several types of major substation equipment as a guide to repair or replacement decision making. These thresholds do not function as mandatory replacement deadlines, nor do they operate independently of the JIT framework. Under this approach, a transformer with an estimated industry service life of 45 years may be considered eligible for repair until 67.5 years (1.5 x 45 years), after which it must be replaced. While equipment age is only one of many variables used to inform replacement decisions for major equipment, and age-based thresholds may prove a mechanism for removing the oldest equipment from the system, this strategy allows equipment to remain in service beyond its intended service life as reported in the ORV.⁴¹

The table below summarizes PG&E’s current age limit thresholds applied to major substation equipment.

Table 18: Equipment PG&E Age Limit Replacement Thresholds⁴²

Equipment	Service Life	Replace Asset if Age Exceeds 1.5x Service Life	% of In-Service Equipment Exceeding 1.5x Service Life
Distribution Transformers	45	67.5	25.7%
Transmission Transformers	45	67.5	10.5%
Unit Substations	45	67.5	59%
Distribution Regulators	40	60	9%
Transmission Regulators	40	60	15.8%
Distribution Breakers	50	75	0.1%
Transmission Breakers	50	75	1.3%
Reactors and Capacitors Transmission	25	37.5	10%

PG&E’s ORV report outlines a proactive long-term replacement strategy, complimentary to JIT and emergency replacements, which is focused on the targeted replacement of a calculated number of major substation equipment each year. This approach draws on asset age, asset health models and condition analyses, to ensure the average age of major equipment in service across the system remains below or is aligned with established industry service life

⁴¹ ORV Substation Maintenance Advisory, July 25, 2025 (p.87) p. 87. Note: This data is outlined in PG&E’s Substation Equipment Failure Procedure, PG&E Utility Procedure TD-3350P-15, Rev 3, dated December 6, 2022. The service life data reference in the Procedure comes from the United States Bureau of Reclamation.

⁴² Substation Equipment Failure Procedure, PG&E Utility Procedure TD-3350P-15, Rev 3, dated December 6, 2022



expectations outlined in Table 18.⁴³ Historically, PG&E used an asset replacement guardrail approach to determine the minimum annual replacement volume required to maintain steady-state replacement operations.⁴⁴ However, the ORV noted that capital investment in substation assets has been constrained in recent years, with allocated funding frequently redirected toward work in other programs such as capacity expansion projects and wildfire mitigation. The ORV indicates that such funding constraints have affected PG&E’s ability to perform proactive replacement of high risk or critical substation assets per its long-term plan, resulting in deferred replacements and short-term repairs on critical assets, which are, at times, already operating beyond their service life and/or above their nameplate capacity.⁴⁵

Following concerns raised by PG&E in the ORV, the ISM requested a progress update on PG&E’s proactive replacement activities for major equipment, along with details on historical and current compliance with its proactive asset replacement guardrails. Information obtained through subsequent data requests and interviews with PG&E personnel indicates proactive equipment replacements have not kept pace with PG&E’s aging asset population for major substation equipment, and PG&E does not consider its forecasted proactive replacement rate sustainable. Table 19 below summarizes the average age and average age of failure of PG&E’s critical assets alongside industry expectations for service life. It also provides the recommended guardrail replacement rate developed by PG&E for 2025 and actual JIT and planned replacements that occurred over the course of that operating period.

Table 19: Summary of PG&E’s Critical Assets vs. Industry Expectations

Equipment	2025 Equipment Count	Equipment Attribute	Average Age (Years)	Median Age (Years)	PG&E Average Age of Failure	Industry Service Life	% of Assets Over Average Age of Failure	Guardrail Minimum Replacement Rate (unit per year)	2025 Actual Replacement Rate	
									Emergency (JIT/Failure)	Planned
Distribution Transformers	761	Single-Phase	59	70	73	45	49%	10	60	0
	1,162	Three -Phase	31	25	48	45	25%	24	17	0
Transmission Transformers	235	Single-Phase	22	24	39	45	48%	6	0	4
	140	Three -Phase	18	18	40	45	1%	3		
500kV Transformers	62	Single-Phase	22	22	33	45	30%	2		
Distribution Regulators	631	Single-Phase	18	15	27	40	22%	N/A		
	114	Three -Phase	56	65	57	40	54%	N/A		
Transformer Regulators	19	Three -Phase	30	19	48	40	35%	N/A	32	29
Distribution Breakers	248	Oil	60	59	52	35	44%	7		
	2,674	Vac	23	20	35	35	20%	76		
Transmission Breakers	3,732	Oil	54	56.5	52	37	64%	6	35	21
		SF6	18	17	37	37	2%	88		
		Vac	6	4	N/A	N/A	N/A	N/A		
Batteries	193	Transmission	11	12	17		19%	11		
	601	Distribution	10	10	17	15	11%	54		

The average age of many of PG&E’s distribution and transmission transformers, circuit breakers and regulators exceed industry service life expectations. In addition, a significant percentage of PG&E’s assets remain in service beyond intended useful life age-limit thresholds (Table 19) and over the average age of failure for those equipment types. According to PG&E, the company is also experiencing challenges associated with an inconsistent approach to replacing or upgrading minor equipment when major equipment replacements occur through

⁴³ ORV Substation Maintenance Advisory, July 25, 2025 (p.77)

⁴⁴ PG&E. (2024, June 6). Substation Asset Management Plan (AMP): TD-8103_REV3.

⁴⁵ ORV Substation Maintenance Advisory, July 25, 2025 (p.78)



the JIT strategy or emergency replacement activities. As a result, PG&E reported that a growing population of major substation equipment is operating under increased stress and overloaded conditions across the system.

PG&E confirmed that spending on reactive maintenance associated with equipment failure and emergency work increased while PG&E deprioritized ongoing proactive replacements of aging assets since 2013 or in some cases, suspended as of 2025. The reallocation of funding associated with this shift in maintenance strategy was highlighted in the 2024 RSAR. As a result of this change, PG&E inconsistently replaced substation assets within the guardrails outlined in the company’s AMP. Figure 12 below provides insight as to how PG&E’s approach to proactive (planned) asset replacement has shifted toward JIT and emergency replacements over the past decade for both transmission and distribution circuit breakers and transformers.⁴⁶

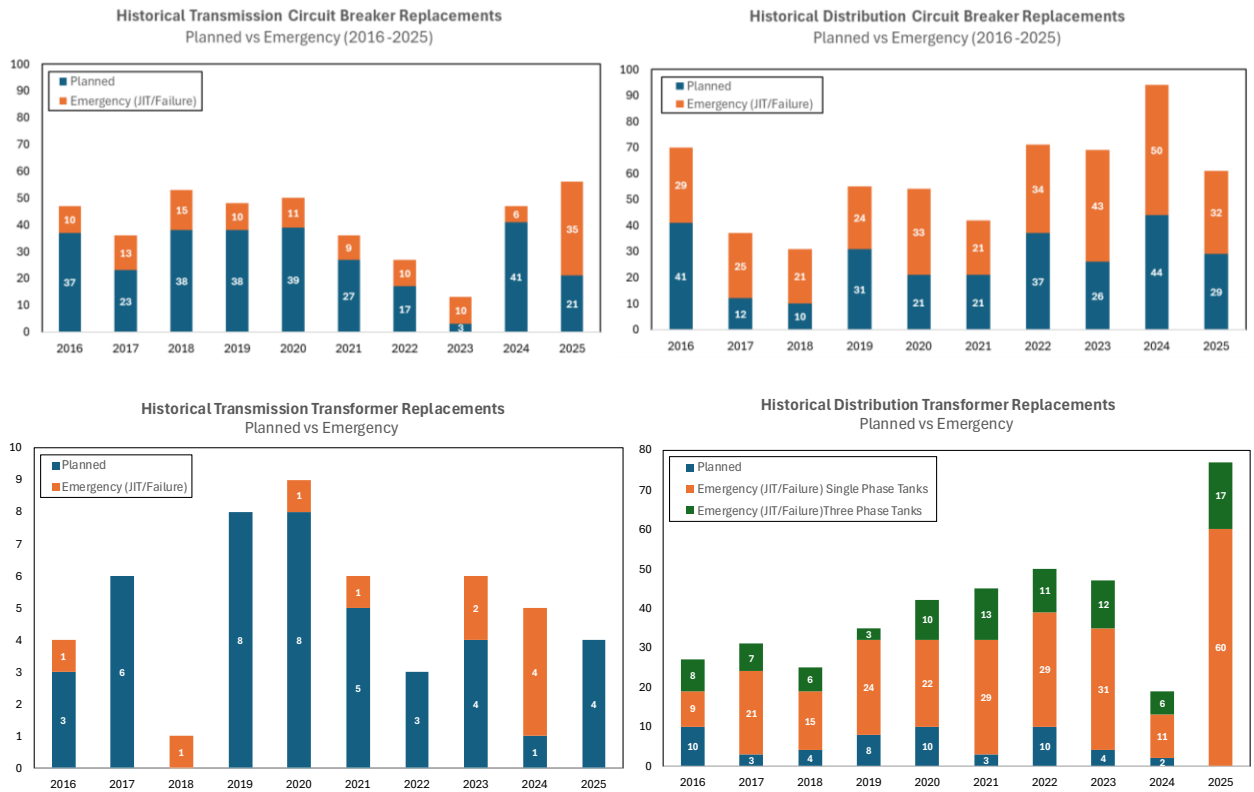


Figure 12: Historical Transmission and Distribution Circuit Breaker and Transformer Replacements

PG&E Asset Management SMEs cautioned that if substation assets are not being replaced within the guardrails, even at a minimum, the increasing backlog of required replacement work associated with this failure will not be executable due to financial, resource, and clearance

⁴⁶ PG&E Data regarding Substation Asset Age Profile and Asset Health and interviews with PG&E Substation Asset Management team



constraints.⁴⁷ Additionally, PG&E forecasted that it will be unable to meet guardrail replacement targets into the future for substation circuit breakers and transformers replacements, as illustrated in the Table 20 below.

Table 20: Substation Asset Replacement Forecast vs. Asset Guardrail⁴⁸

Program/Metric	Annual Volume						
Category	2025	2026	2027	2028	2029	2030	2031
Distribution Sub Breaker Replacements (48D + 59E)	19	42	75	60	113	71	40
Guardrail Target	80	80	80	80	80	80	80
Variance from Guardrail	-61	-38	-5	-20	33	-9	-40
Transmission Sub Breaker Replacement (65E)	0	33	39	34	36	32	32
Guardrail Target	92	92	92	92	92	92	92
Variance from Guardrail	-92	-59	-53	-58	-56	-60	-60
Distribution Transformer Replacements (58A/L+59C/D)	4	19	23	25	25	26	26
Guardrail Target	37	37	37	37	37	37	37
Variance from Guardrail	-33	-18	-14	-12	-12	-11	-11
Transmission Transformer Replacement (65E)	0	8	5	4	5	5	4
Guardrail Target	5	5	5	5	5	5	5
Variance from Guardrail	-5	3	0	-1	0	0	-1

During the current ISM reporting period, PG&E described its approach to replacement of minor substation equipment, which were characterized as equipment such as insulators and surge arrestors that are interconnected with major substation equipment. PG&E indicated that under its current emergency equipment replacement strategy, minor equipment is not actively monitored for replacement and is left in place when major equipment is replaced on an emergency or JIT basis to minimize the scope of JIT projects. PG&E further noted that this approach represents a departure from prior practice, under which minor equipment was replaced concurrently with planned (proactive) major equipment replacement.

PG&E noted that this change in practice developed over the ten-year period spanning 2015 to 2025 and is directly attributable to sustained funding constraints for planned substation asset health projects. Spending for planned asset health programs (MWC 46, 48, 54, 58, 60, 61, 64, 66, and 68) remained flat throughout the ten-year period, with significant reductions in 2017 and 2023 resulting in project deferrals. Over the same ten-year period, spending on emergency work (MWC 59 and 65) steadily increased, a pattern consistent with a system increasingly reliant on reactive rather than proactive intervention.

The below table depicts cumulative spending trends for the planned and emergency MWC for asset health from 2015 – 2025:

⁴⁷ ORV Substation Maintenance Advisory, July 25, 2025 (p.78) RE: Substation Maintenance Program Risk Advisory Discussion. Personal communication.

⁴⁸ Guardrail data per PG&E. (2024, June 6). Substation Asset Management Plan (AMP): TD-8103_REV3; asset replacement forecast data per PG&E. (2025, April 30). TD_Subst_21-31_Historical_Forecast_250430.

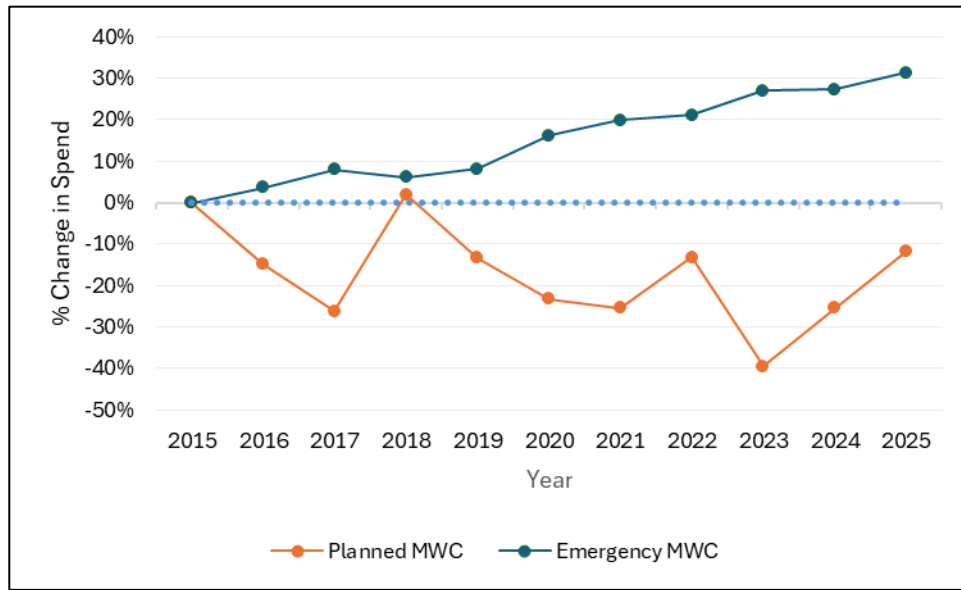


Table 21: Change in Cumulative Spending for the Planned and Emergency MWC from 2015 – 2025

Substation Maintenance and Inspection

CAISO’s 2025 AMR and PG&E’s ORV Substation Maintenance Advisory each identified maintenance execution and backlog as significant areas of concern within PG&E’s substation program where: preventative maintenance activities are completed late or are outstanding, corrective notifications are aging past required due dates, and emergency work is displacing planned proactive maintenance. During the current ISM reporting period, the ISM reviewed PG&E’s substation maintenance and inspection programs in greater detail, including the structure and compliance obligations of PG&E’s preventative and corrective maintenance programs, the current state of its maintenance backlog, and the condition of battery systems across the substations visited.

As background, the purpose of substation maintenance and inspection programs are to ensure reliability, employee and public safety, and long-term performance of critical assets. These programs are intended to support asset management strategy by identifying and remediating asset deficiencies prior to failure. Operationally, such programs rely on adherence to well documented procedures, consistent field execution with supporting quality control and assurance programs, comprehensive data to drive decision making, and alignment with regulatory expectations for safety and compliance. Findings outlined in both the CAISO and ORV reports highlighted multiple areas of PG&E’s current maintenance and inspection practices. Furthermore, substation maintenance records reviews and interviews conducted with key Substation Maintenance & Construction personnel provided additional insight as to maintenance execution and funding constraints currently impacting the effective operation of the programs.

Substation Maintenance Programs

PG&E’s substation maintenance programs encompass two distinct categories of maintenance activities, preventative and corrective, each governed by defined standards, completion timelines, and compliance obligations. A key requirement is GO 174.



PG&E’s preventative maintenance program is a periodic program comprised of scheduled, time-based or cycle-based activities performed at defined intervals by substation electricians. Preventative maintenance provides the foundation of PG&E’s condition-based monitoring approach to maintaining substation assets and informs the JIT replacement strategy used for major equipment. The ISM notes that reductions in the frequency of preventive maintenance may limit early detection of developing asset conditions leading to an increase in corrective response.

Corrective maintenance is a non-periodic program that is condition driven, initiated in response to an identified deficiency or equipment failure. PG&E’s corrective maintenance program uses a priority-coded notification system governed by Utility Standard TD-3322S to document work. The priority code structure is intended to ensure that the most consequential defects identified receive the most immediate response.

Table 22 below provides completion timeline requirements for LC notifications and corresponding dates.

Table 22: Timeline Requirements for LC Notifications and Dates⁴⁹

Priority	Notification Date	Required End Date	Out of Compliance Date
Priority A (within 30 days)	9/1/2023	10/1/2023	Must close within 30 days
Priority B (within 90 days)	9/1/2023	11/30/2023	11/30/2023
Priority E (within 365 days)	9/1/2023	9/1/2024	1/1/2025 ⁵⁰
Priority F (greater than 365 days)	9/1/2023	9/1/2025	No defined date

Preventative maintenance is scheduled to monitor asset conditions and detect issues prior to imminent failure, while corrective maintenance addresses identified deficiencies. Both are governed by compliance timelines where missed work increases risk, reduces visibility, and allows equipment issues to persist or worsen. Table 23 below summarizes the key distinctions between both maintenance programs.

⁴⁹ PG&E Utility Standard: TD-3322S, Substation Equipment Maintenance Requirements (p.4). Note that the dates are arbitrary and used for illustrative purposes

⁵⁰ For Priority E notifications, the out-of-compliance date is the 1st day of the year following the year in which the required end date occurs.



Table 23: Key distinctions between Preventative and Corrective Maintenance Programs

Preventative Maintenance	Corrective Maintenance
<p>Definition</p> <p>Scheduled, time-based or cycle-based maintenance activities performed at defined intervals regardless of observed equipment condition. Frequency is based on regulatory standards and PG&E internal requirements</p>	<p>Definition</p> <p>Condition driven maintenance that is initiated in response to an identified deficiency or equipment failure. Maintenance required is documented through Line Corrective (LC) notifications in PG&E's SAP Work Management System</p>
<p>Examples</p> <ul style="list-style-type: none"> • Visual inspections of facilities conducted by substation electricians at defined intervals. Annual Infrared (IR) inspections of energized equipment • Oil sampling and analysis • Functional performance testing of circuit breakers, protective relays, and batteries • Nitrogen pressure verification for transformer systems • Fire protection system inspection, test, and maintenance 	<p>Examples</p> <ul style="list-style-type: none"> • Oil leak remediation • Nitrogen system lead remediation • Cooling fan replacements Insulator repair or replacement • Animal guard repair or installation • IR hot spot remediation
<p>Compliance framework</p> <p>Completion of activities is triggered by predefined maintenance cycle intervals defined by internal PG&E standards and processes. Overdue status determined by TD-3322S schedule non-compliance constitutes a GO 174 Rule 12 Violation.</p>	<p>Compliance framework</p> <p>Completion of activities is governed by LC priority codes, A, B, E, & F. Out-compliance-dates are defined in PG&E procedures and non-compliance constitutes a GO 174 Rule 12 Violation.</p>
<p>Backlog Risk</p> <p>Missed preventative maintenance results in undetected equipment degradation. PG&E's condition-based monitoring programs depend on completion of preventative maintenance and gaps create blind spots in PG&E's condition awareness</p>	<p>Backlog Risk</p> <p>Unresolved LC notifications allow identified deficiencies to persist and progress. Past due Priority B & E notifications identified in CAISO's report include:</p> <ul style="list-style-type: none"> • Oil leaks/weeping (CT/PT, oil switches), cracked glass components, damaged capacity wiring • Protection, control and monitoring deficiencies • Station support such as lighting outages and grounding repairs

Maintenance Backlog and LC Notifications

The AMR identified deficiencies related to the timely completion of both periodic and non-periodic maintenance notifications, and characterized the conditions observed as likely indicative of a system-wide issue within PG&E's substation maintenance program. To independently assess the prevalence and current applicability of these findings, the ISM requested open and historical LC notification maintenance records from PG&E covering a five-year lookback period from 2021 - 2025. The maintenance tag analyses conducted are reviewed in detail in the following subsections.

Five Year LC Maintenance Notification Trends

During the current ISM reporting period, the ISM conducted an analysis that examined the quarterly relationship between notification creation and closure activity alongside the growth of the cumulative open tags during that period, providing a quantitative, system-wide assessment of how maintenance activities impacted the closure and completion of substation maintenance notifications.

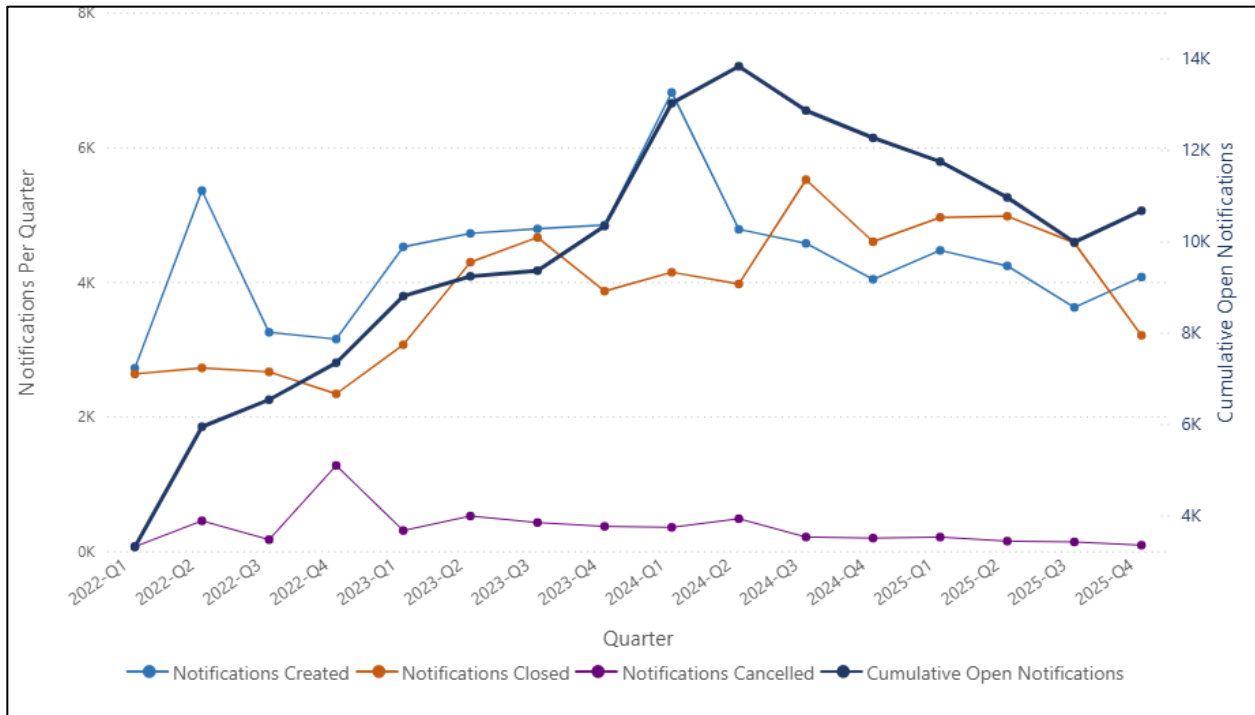


Figure 13: Substation Notification Trend (2020 to 2025)⁵¹

Figure 13 depicts the quarterly volume of substation notifications created, closed and cancelled across PG&E’s substation LC maintenance records from 2022 through 2025, alongside the cumulative open notification at the end of each quarter. The left axis reflects quarterly flow, those created, those closed and those cancelled within each period, while the right axis reflects cumulative open notifications carried forward at period end.

As depicted above, the cumulative population of open notifications grew steadily from 2022, reaching a peak of nearly 14,000 in 2024-Q2, representing a sustained period in which notification creation outpaced resolution. PG&E attributed the increase of notifications during this time to a work management system transition from APM to SAP, and characterized it as a change “implemented to improve overall substation visibility, enhance risk awareness, and ensure that identified conditions were more consistently documented, prioritized, and tracked through the work management process.” The ISM notes that PG&E’s explanation focuses on the documentation and visibility effects of the APM to SAP transition, but it does not address whether the growth in open notifications reflects underlying changes in field conditions.

Beginning in 2024-Q3, closure activity accelerated and surpassed notification creation for five

⁵¹ PG&E closed and open LC maintenance tags from 2021-2025. The analysis performed is based on the volume of substation LC notifications created and closed in each quarter of the review period, as derived from datasets provided by PG&E. All datasets provided by PG&E listed a ‘Notification Date’ field which was assumed as the date the notification was initially entered into PG&E’s SAP work management system. For notifications within the Close Notifications dataset, a ‘Reference Date’ field was included in lieu of a completion date field which was assumed as a close proxy for the date on which the associated maintenance work was completed, or the notification was administratively closed in SAP, as no explicit actual completion date was provided.



consecutive quarters through 2025-Q3, resulting in a reduction in cumulative open notifications from its peak to approximately 10,000 notifications. Cancelled notifications remained low throughout the review period, indicating that the observed reduction in notifications during this period is likely reflective of work completed rather than administrative closure of open notifications. As of 2025-Q4, notification creation exceeded closures and the open population of notifications grew to approximately 10,500 notifications.

To further assess the structural drivers of open tag accumulation depicted in Figure 13 above, the ISM analyzed the priority composition of both notifications created per quarter and the cumulative open notifications at period end across the same five-year period. Figure 14 and Figure 15 present this analysis and depict the disaggregation of notification volumes by priority classifications to assess relationships between both flow of new work entering the maintenance system of record and the composition of work that accumulated in the open notifications.

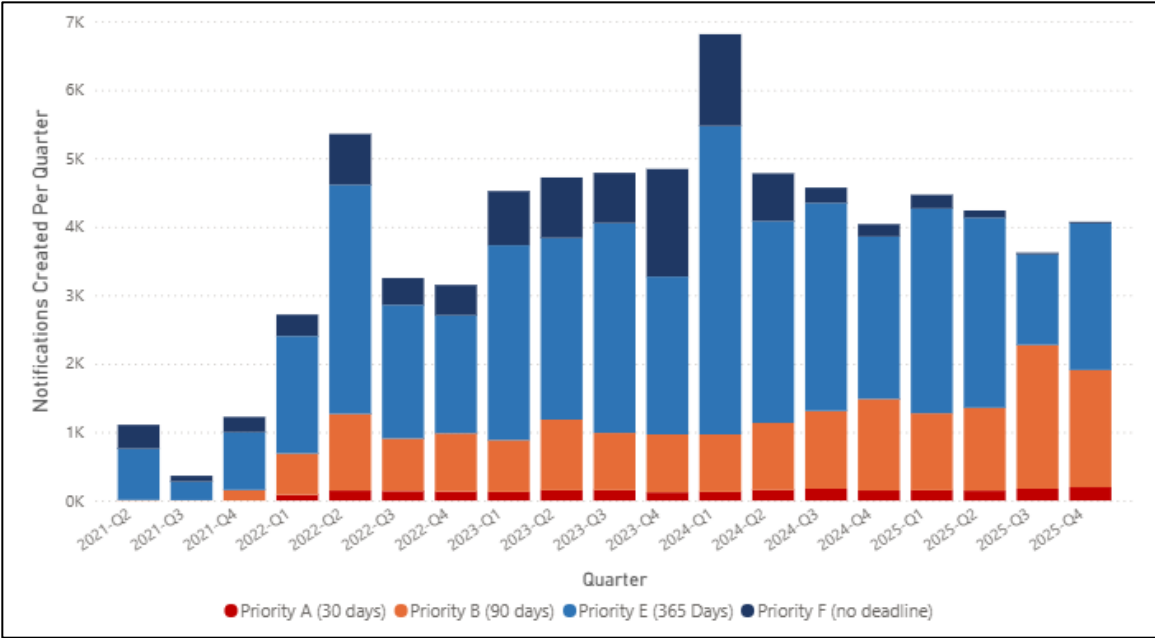


Figure 14: Substation Notification Created by Priority (2021 – 2025)

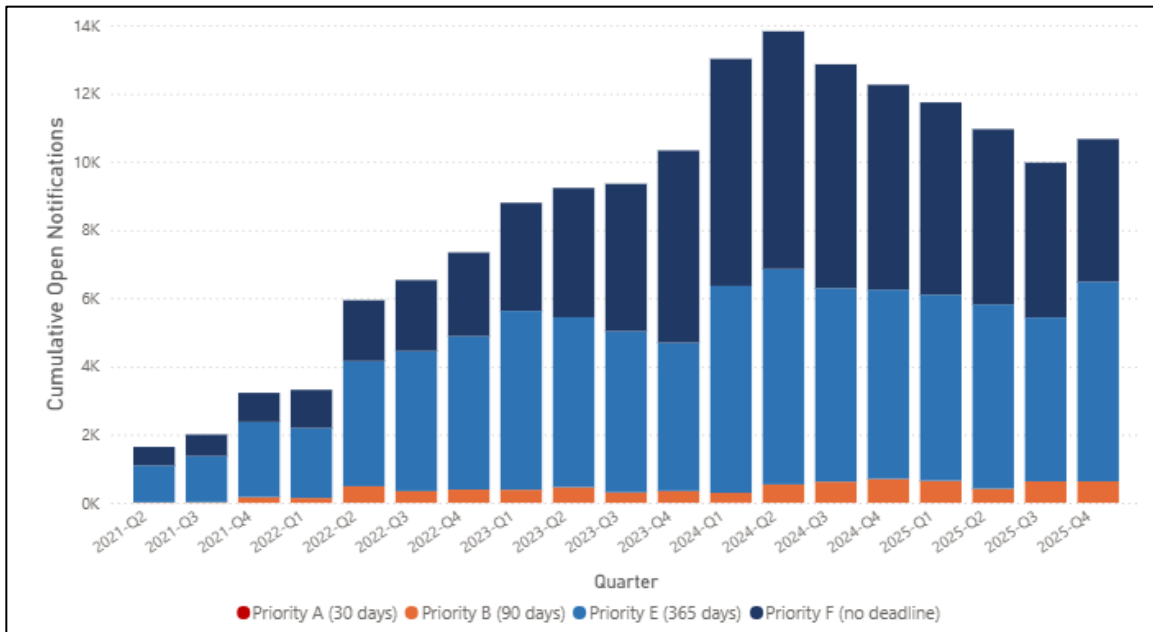


Figure 15: Cumulative Open Notifications by Priority by Period End (2021-2025)

As depicted in Figure 14, Priority E notifications represent the primary category of substation maintenance work created across the five-year period, consistently comprising the largest portion of quarterly notification volume. Priority F notifications, which carry no GO 174 out-of-compliance date, represent the second largest category in most quarters, with a notable spike in 2024-Q1 coinciding with the highest creation volume identified in the open notification trend analysis. Priority A and B notifications, which have the most urgent compliance timelines, constitute a comparatively small proportion of notifications created in each quarter reviewed.

Figure 15 illustrates how this priority distribution impacted cumulative open notifications. While Priority E notifications represent a significant volume of open notifications throughout the review period, which is reflective of both their high creation volume and extended completion window, Priority F notifications grew significantly from 2022-Q1 to 2024-Q2. PG&E indicated these notifications are typically used for long-term replacement projects and conditions that do not pose an immediate operational or safety risk. Furthermore, PG&E conveyed that the increase in F-priority notifications is primarily driven by a growing number of asset replacement needs, as well as the strategic shift away from monitoring abnormal conditions in APM and toward more formal tracking in SAP. As of 2025-Q4, PG&E indicated that the resumption of growth in open E and F priority was attributable to a misalignment between Substation maintenance and construction (M&C) funding levels and workload required to address associated notifications.

Notification Compliance Performance

The ISM reviewed historical closure records and current open status of Priority A, B, and E notifications against respective GO 174 regulatory out-of-compliance dates, examining both the rate at which notifications were completed within required timelines and the severity of lateness for those that were not.



Figure 16: Notification Compliance Performance for Closed and Open Notifications (2021-2025)

As shown in Figure 16 above, across the five-year period reviewed, PG&E substation records reflect 58,715 closed Priority A, B, and E notifications. Of these, 1,146 were closed after their GO 174 regulatory out-of-compliance date, yielding a regulatory late closure rate of 1.95%. As of February 6, 2026, 872 Priority B and E notifications remain open past their regulatory compliance date, representing an open out of compliance rate of 11.89% against the total open A, B, and E notification population. The maximum overdue days recorded across the five-year period is 1,139 days, more than three years past the notification’s regulatory compliance timeline.

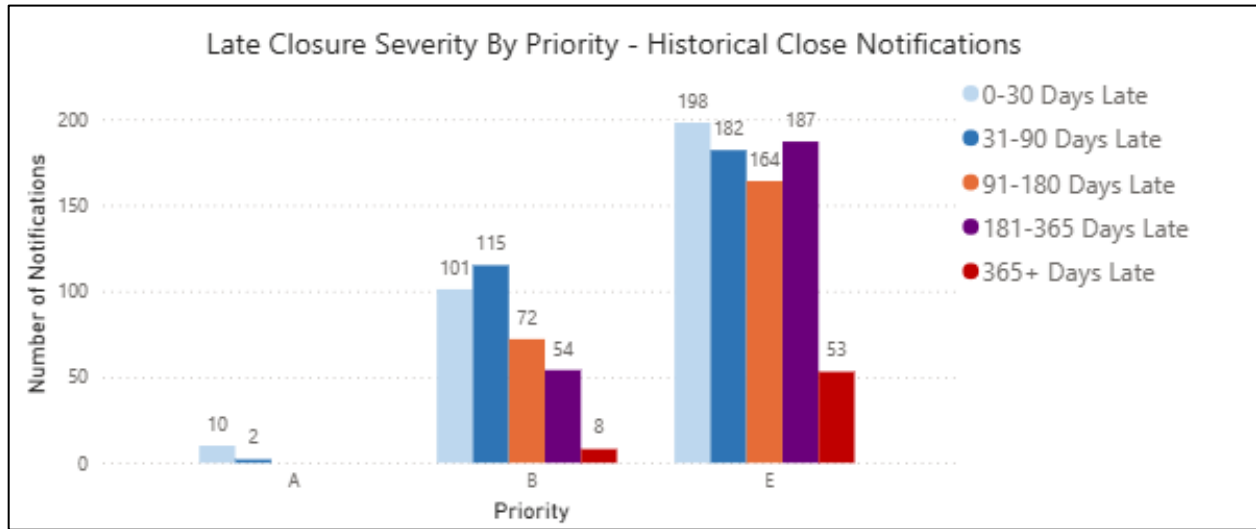


Figure 17: Late Closure Severity by Priority - Historical Close Notifications

As depicted in Figure 17, Priority E notifications account for the largest late closure population, with 784 late out-of-compliance notifications distributed consistently across all days past due severity buckets. For Priority B, notifications were closed late most frequently from 0 – 90 days past their out-of-compliance dates, with additional notifications spread across all severity buckets up to and including 365 days or more late. Priority A notifications carry a 30-day compliance requirement, and all 12 late closures in this category represent instances where the most urgent safety-critical maintenance was not completed within its required window.

As of February 6, 2026, 872 Priority B and E notifications were open and past their regulatory out-of-compliance date. As depicted in Figure 18 below, this population is concentrated almost entirely in Priority E, with 812 of the 871 notifications crossing the January 1, 2026 out-of-compliance threshold. Under PG&E’s notification framework, all Priority E notifications created during calendar year 2024 carry an out-of-compliance date of January 1, 2026, regardless of when they were created in 2024.

The remaining 59 open out-of-compliance Priority E notifications represent notifications that



were already past their regulatory out-of-compliance date before January 1, 2026, comprised of open periods ranging from 401 to 767 days late. These notifications represent sustained, long duration compliance failures with PG&E's open notification maintenance records. There are currently no open Priority A notifications for maintenance corrective work, indicating PG&E is presently adhering to the 30-day regulatory compliance period associated with that type of notification.

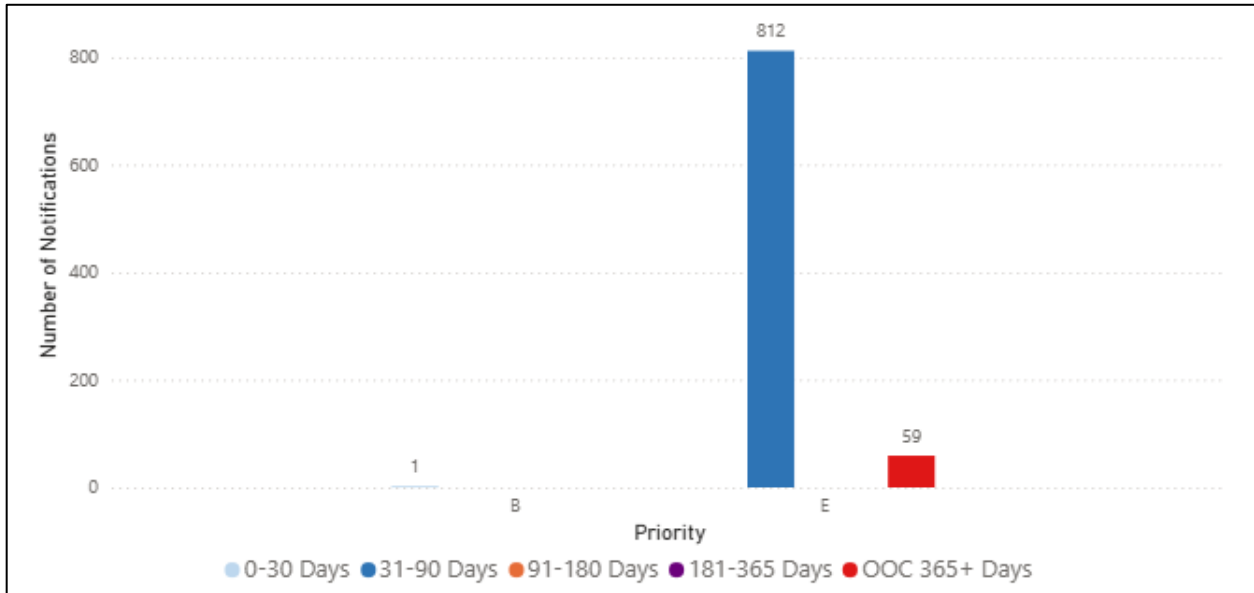


Figure 18: Currently Open Out-of-Compliance Notifications by Priority (B and E Notifications Only) As of February 6, 2026

The ISM inquired with PG&E regarding the notable increase in the regulatory late closure of the 872 outstanding tags as it appeared to be a meaningful deviation from historical rates. PG&E acknowledged that 2025 Substation M&C funding was insufficient to meet the expense maintenance workload required to address tags approaching their out-of-compliance date. As of April 16, 2026, 112 of the 872 (13%) were closed.

Frequency of Substation Maintenance Activities

The concerns identified in the CAISO's 2025 AMR, and PG&E's ORV Substation Maintenance Advisory regarding late and outstanding maintenance activities prompted the ISM to compare the frequency of PG&E's maintenance testing against recognized industry guidance. As a reference benchmark, the ISM utilized the ANSI/NETA Standard for Maintenance Testing Specifications for Electrical Power Equipment and Systems,⁵² published by the InterNational Electrical Testing Association (NETA).

ANSI/NETA MTS-2023 guidance expresses maintenance frequencies in months and are further calibrated by a multiplier derived from two variables: the condition of the equipment (rated as Poor, Average, or Good) and the reliability requirement of the system (rated as Low, Medium,

⁵² 2023 ANSI/NETA Standard for Maintenance Testing Specifications for Electrical Power Equipment and Systems.



or High). Under this framework, equipment in average condition with a medium reliability requirement would be maintained at the base frequency, while equipment in poor condition or with high reliability requirements would warrant more frequent maintenance. This is highlighted in Table 24 below.

Table 24: Maintenance Frequency Matrix

MAINTENANCE FREQUENCY MATRIX				
		Equipment Condition		
		Poor	Average	Good
Equipment Reliability Requirement	Low	1.0	2.0	2.5
	Medium	0.50	1.0	1.5
	High	0.25	0.50	0.75

The following provides an example of the application of the Maintenance Frequency Matrix. If a liquid filled transformer is in “average” condition and has a “low” reliability requirement, then the criticality factor is 2. Referring to the table below, for a liquid filled transformer NETA recommends a visual inspection frequency of once per month multiplied by the criticality factor. Therefore, according to NETA, the liquid filled transformer should undergo a visual inspection every 2 months.

The ISM reviewed PG&E's current maintenance testing frequencies for relevant substation equipment types, drawing on findings from PG&E's ORV, CAISO's AMR, and interviews with PG&E substation personnel. PG&E's current frequencies were then compared against the ANSI/NETA MTS-2023 guidance ranges for both 'Visual' and 'Visual, Mechanical, and Electrical' inspections. The results of this comparison are summarized in Table 25 below. It is noted that the PG&E frequencies reflected in the table are based on the ISM's review of available information and interviews with PG&E personnel. It may not fully capture variations in PG&E's current practices across all regions and equipment types.



Table 25: ANSI/NETA MTS-2023 Guidance and PG&E Frequency of Maintenance Testing

Description	Visual Inspection			Visual & Mechanical & Electrical		
	ANSI/NETA (Months)	Criticality Range* (Months)	PG&E's** Frequency (Months)	ANSI/NETA (Months)	Criticality Range* (Months)	PG&E's** Frequency (Months)
Switchgear and Switchboard Assemblies	12	3 - 30		12	3 - 30	
Liquid-Filled Transformers	1	0.25 - 2.5	1 - 2	24	6 - 60	72 - 84
Transformer Sampling	--			12	3 - 30	12 - 24
Infrared Only	--			12	3 - 30	12 - 24
Switches						
Air, Low-Voltage	2	0.5 - 5	1 - 2	36	9 - 90	96 - 108
All Other	1	0.25 - 2.5	1 - 2	24	6 - 60	96 - 108
Circuit Breakers (all classes)	1	0.25 - 2.5	1 - 2	36	9 - 90	96 - 108
Circuit Breaker Sampling	--			12	3 - 30	12 - 24
Circuit Switchers	1	0.25 - 2.5	1 - 2	36	9 - 90	96 - 108
Protective Relays						
Electromech and Solid State	1	0.25 - 2.5	1 - 2	24	6 - 60	96 - 108
Microprocessor-Based	1	0.25 - 2.5	1 - 2	36	9 - 90	96 - 108
Step-Voltage Regulators	1	0.25 - 2.5	1 - 2	24	6 - 60	96 - 108
Regulator Sampling	--			12	3 - 30	12 - 24
Load Tap-Changer (LTC)	1	0.25 - 2.5	1 - 2	24	6 - 60	96 - 108
LTC Sampling	--			12	3 - 30	12 - 24
Batteries	1	0.25 - 2.5	1 - 2	12	3 - 30	12 - 24
Battery Chargers	1	0.25 - 2.5	1 - 2	12	3 - 30	12 - 24

* Criticality based on ANSI/NETA Maintenance Frequency Matrix Factors (0.25 for most critical and 2.5 for less critical)

** PG&E's frequency estimated based on interviews.

The ISM observed that PG&E's current maintenance and testing intervals for several equipment categories appear to extend beyond the ranges suggested in the ANSI/NETA MTS-2023 guidance. In the context of an aging asset fleet operating beyond intended service life, extended maintenance intervals may reduce the frequency of condition monitoring.

ISM Substation Field Investigations

The ISM conducted field visits to seven PG&E substations during the current ISM reporting period, all within the Bay Area. The substations were selected in part because they were among those reviewed in the CAISO's 2025 AMR, and because they are geographically concentrated in the Bay Area, a region identified by both CAISO and the PG&E ORV as having elevated maintenance compliance concerns and staffing constraints. The ISM was accompanied by PG&E operations, asset management, and maintenance personnel during each visit. Site visits included observations of general equipment conditions, discussions with PG&E staff regarding CAISO findings and corrective actions, maintenance procedures, and inspection of specific equipment and systems flagged in the CAISO report.

CAISO Finding Follow-Up

With respect to the specific findings and concerns identified in CAISO's 2025 AMR, the ISM observed the following at the time of its site visits:

Battery and DC systems, which were the subject of the most significant CAISO finding, appeared to be in generally good working condition across the substations visited. Battery systems at the stations inspected were operational, fluid levels appeared within specifications, and most battery rooms were air-conditioned. PG&E reported that it recently implemented an advanced Battery Training Program in response to CAISO observations, and that PG&E corrected issues



identified during the CAISO inspection or the issues were the subject of open maintenance notifications.

At one substation, CAISO observed abandoned equipment and a steel dumpster stored in close proximity to energized 115kV buswork. PG&E substantially addressed the yard encroachment concern at this substation by the time the ISM visited. PG&E relocated spare equipment and the dumpster from under the 115kV bus, though some equipment storage remained on site.

PG&E reported that prior to the ISM's site visits it repaired the nine condensation heaters identified as non-operational during the CAISO inspection, and the ISM observed all were operational. PG&E indicated it completed a procedure assessment to prevent recurrence by November 2025.

Regarding CAISO's finding on HMI terminal access, the ISM observed HMI systems in place and accessible at multiple substations visited. PG&E reported to the ISM that it will ensure that appropriately trained personnel, with access rights to the HMI, accompany CAISO representatives during future AMRs to facilitate access.

General Field Observations

PG&E opened each substation visit with a safety tailboard meeting, during which personnel identified site-specific safety concerns, located emergency equipment, and provided emergency services information. The ISM noted that access to all substations was restricted through fencing, enclosures, or dedicated security infrastructure. One substation was fully enclosed within an urban building, while others were enclosed by masonry perimeter walls. These physical security upgrades were implemented in response to the 2013 attack on PG&E's Metcalf substation.⁵³ A ballistic wall at a substation represented another security upgrade (Figure 19 below). Keycards and access codes restricted access to substation gates and control room doors.

Across the substations visited, the ISM noted oil leaks on transformers and reactors at several facilities. In each case, PG&E stated that the leaks were associated with oil sampling points rather than structural failures and were managed with drip pans and absorbent materials (Figure 19 below). PG&E noted that full repair of these leaks requires draining and degassing equipment; and is therefore deferred to scheduled major maintenance intervals. The ISM observed that this deferral practice is consistent across facilities and appears to be a deliberate maintenance strategy rather than an isolated oversight.

⁵³ In April 2013, attackers fired more than 100 rifle rounds at PG&E's Metcalf transmission substation south of San Jose, disabling 17 transformers and causing approximately \$15 million in damage. In response, PG&E reported significant physical security upgrades across its substation fleet, including the construction of masonry perimeter walls at several facilities, evidence of which the ISM observed at a few of the substations visited during the current reporting period.



Figure 19: (Left) Ballistic wall; (Middle and Right) sample port oil leaks

The ISM also observed significant quantities of spare and surplus equipment stored throughout multiple substations. PG&E indicated that this material varies in status, some is new equipment awaiting deployment, some is being reconditioned, some are designated for disposal, and some are retained for contingency use (Figure 20 below). PG&E noted that formally tracked emergency replacement equipment is managed through its Capital Emergency Material (CEM) system, which covers transformers, circuit breakers, and mobile substation units. However, equipment held informally for contingency purposes is not tracked in any database or inventory system, and PG&E currently relies on informal communication to locate and transfer this material when needed at other locations. The ISM observes that a more formal tracking mechanism for this category of material would improve PG&E's emergency response capabilities and visibility into available spare equipment, a concern also noted in the ORV advisory.



Figure 20: (Left) New spares; (Middle) contingency spares; (Right) designated for disposal

VEGETATION MANAGEMENT

PG&E's VM program is governed by internal VM Standards and Procedures described in ISM Report 7, including Routine and Second Patrols conducted on both 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 Vegetation Management for Operational



Mitigation (VMOM). According to PG&E, FTI, TRI, and VMOM coordinate with Routine and Second Patrols to minimize customer touch points, increase productivity, and maximize effectiveness of the VM budget. Collectively, PG&E's VM programs maintain vegetation across approximately 80,000 miles of distribution and 18,000 miles of transmission.

Effective November 15, 2025, PG&E implemented a consolidation of VM programs. Under the new structure, PG&E performs Routine and Hazard Patrols, FTI, and TRI concurrently. Two distribution programs, Routine Patrol and Hazard Patrol, now encompass Standard and Elevated work categories. PG&E incorporated TRI under the Standard work category on both patrols, while FTI is performed under the Elevated work category. PG&E redesignated VMOM as a "Weather Driven Event Procedure," incorporating PIIRs and pre/post outage investigation. Programs unaffected by consolidation include Transmission, Vegetation Control, Estimating Arborist, and Wood Management.

As reported in ISM Report 7, PG&E's 2026-2028 WMP outlines the following VM commitments:

- Consolidation of Distribution Inspection Programs
- Incorporation of Remote Sensing (Light Detection and Ranging (LiDAR), Satellite, and/or Imagery) to inform or supplement inspections in HFTD
- Utilization of analytics to risk prioritize inspections and work execution
- Continued execution of 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.

PG&E leadership indicated that where system improvement or underground conversion projects are planned or in progress, all VM inspections and tree work activity will continue until overhead electric infrastructure is completely removed.

During the current ISM reporting period, the ISM continued to monitor Routine and Second Patrols, FTI, TRI, and VMOM through November 2025. Beginning December 2025, the ISM transitioned observations to the 2026 Program Consolidation structure, which is detailed later in this section.

Vegetation Management Inspector

PG&E's VM program is executed through a workforce of contracted and internal Vegetation Management Inspectors (VMIs). PG&E tracks VMI credentialing (both contracted and internal personnel) through the Industrial Training Services (ITS) badging system. ITS badging does not capture years of service or credential qualification. PG&E requires VMIs to complete necessary VM training prior to commencement of work, as well as any potential assigned classroom and web-based courses throughout the year. PG&E requires newly hired VMIs to complete VEGM-0500-Vegetation Management Academy; a four day in-person course completed after the VM Basic Curriculum.



VM Contracts

In 2025, PG&E executed an extension of the unit-based VM contract through year-end 2026. In February 2026, PG&E reported the launch of a Request for Proposals (RFP) for a successor contract, which will remain unit-based and permit up to thirty percent sub-contracting, commencing in 2027.

Under the unit-based contract structure, PG&E expects safety and production performance of all vendors; financial incentives are not included in the contract. PG&E implemented “Safe Work Practices” in 2021, including quarterly safety placemats that track line strikes, motor vehicle incidents, and serious injuries. PG&E provides feedback directly to each vendor on a quarterly basis; vendors with positive safety scores may be eligible for additional resources and potential expansion of their contractor footprint.

Per the Safety Performance provisions of the VM contract, PG&E reserves the right to take corrective and enforcement actions when contractor work is determined to be unsafe or has the potential to create unsafe conditions. Potential disciplinary actions include issuance of a stop work order, formal warning, letter of suspension, or engagement of an alternate contractor.

PG&E implemented a “self-reporting” policy under the current unit-based contract to encourage proactive reporting of near misses and hazards. According to PG&E, this approach fosters transparency and an open channel of communication between client and contractor, enabling fair assessment of safety performance. During the current ISM reporting period, PG&E implemented contractual enforcement provisions against four contract vendors following serious safety-related incidents.

2021	2022	2023	2024	2025
<ul style="list-style-type: none"> Assessment Yard Pilot (Dec 2021) 	<ul style="list-style-type: none"> Updated tree work contracts Rolled out approval-to-work team Published tree work safe work practice procedures Established mandatory safety observations and tool Implemented daily high/life threat finding review process/team 	<ul style="list-style-type: none"> Assessment Yard Go-Live Annual Safety Summit implementation Monthly Contractor Safety Forum 	<ul style="list-style-type: none"> Published tree work safe practice procedure V2 Contractor quarterly performance placements (Q3) Monthly oversight teams Ensuring a Safe Workplace alignment meeting Mandatory tree work micro-learnings 	<ul style="list-style-type: none"> Published Assessment Yard Procedure Span of Control implementation Contractor Risk Trend Matrix Updated Safe 3001p-41 Contractor Safety Oversight Procedure
<p>SIF-A: 3 SIF-P: 14 Rate: 0.9</p>	<p>SIF-A: 1 SIF-P: 18 Rate: 1.24</p>	<p>SIF-A: 2 SIF-P: 14 Rate: 1.1</p>	<p>SIF-A: 1 SIF-P: 1 Rate: 0.1</p>	<p>SIF-A: 1 SIF-P: 4 Rate: 0.28</p>

Figure 21: SIF & Tree Work Milestones (2021-2025)⁵⁴

As reported in ISM Report 7, PG&E observed a decrease in safety-related incidents following the implementation of the unit-based contract which included sub-contracting limitations,

⁵⁴ Rate is incidents per 100,000 trees worked



though PG&E stated that concurrent changes to internal safety protocols may also have contributed to this reduction. Figure 21 shows key safety milestones implemented alongside contract changes from 2021 through 2025. As shown, the Serious Injury and Fatality (SIF) rate declined from 1.24 incidents per 100,000 trees worked in 2022 to 0.10 in 2024 and 0.28 in 2025.

Consolidation of Vegetation Management Programs

PG&E published a whitepaper entitled “*Consolidated Vegetation Inspection Model, A Risk-Informed Framework For PG&E’s 2026-2028 Wildfire Mitigation Plan*” in Q1 2026. The VM Program Consolidation became effective Q1 2026, and within the white paper, PG&E states that the consolidation was influenced in part by specific Office of Energy Infrastructure Safety (OEIS) directives. Based on ACI PG&E 23-17 and ACI PG&E 25U-08, PG&E presented a plan to consolidate its vegetation inspection programs, reduce customer touch points, and streamline procedures, and describe the results of the pilot trees previously prescribed for removal to ensure that inventory reflects current conditions and risk. Revision Notice PG&E 26-09 added further expectations, requiring PG&E to identify which elements of TRI and FTI would be preserved in the Distribution Routine Patrols, establish a timeline with measurable milestones, and continue to track quantitative targets for mitigation. PG&E also stated that the consolidated approach aligns with the industry-standard approach of pairing annual routine inspections with a separate, time-offset pass targeting higher-risk areas.⁵⁵

PG&E consolidated five distribution VM programs into three. The previous Routine Patrol, Second Patrol, FTI, and TRI programs merged into two patrol programs, Routine and Hazard, each encompassing Standard and Elevated work categories. Hazard Patrol is scheduled approximately six months after Routine on an annual basis. PG&E redesignated VMOM as a standalone “Weather Driven Event Procedure,” with historical outage data, reliability metrics, and PSPS events embedded into the program structure. Figure 22 summarizes the program consolidation.

PG&E stated that consolidation is expected to reduce the number of scheduled inspections and customer touch points. As part of consolidation, PG&E implemented a distribution LiDAR pilot program utilizing backpack LiDAR systems operated by internal VM personnel. The pilot is designed to capture imagery for both tree health assessment and strike potential evaluation, with the intent of exploring whether the technology can supplement and streamline VM inspection processes.

⁵⁵ PG&E, Consolidated Vegetation Inspection Model: A Risk-Informed Framework for PG&E’s 2026-2028 Wildfire Mitigation Plan, December 31, 2025 (pages 16-18).

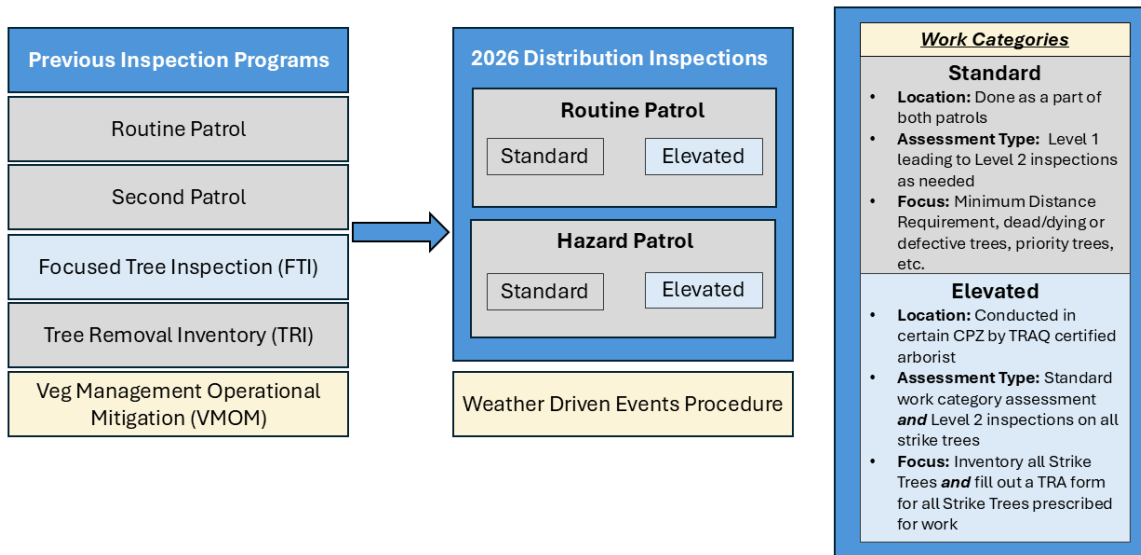


Figure 22: Program Consolidation Overview⁵⁶

2026 VM Distribution Inspections

Under the consolidated structure, VMIs conduct Routine and Hazard Patrols concurrently with Standard and Elevated work categories to minimize customer touch points. Inspection procedures encompass underbuilt spans where transmission facilities are present, as well as idle lines and secondary conductors, including assessment of strain or abrasion on service drops. VMIs consider typical weather patterns for specific geographic areas as part of their assessment processes. Table 26 presents the patrol criteria VMIs apply when prescribing trees for mitigation.

Table 26: VMI Criteria when Prescribing Trees for Mitigation

VM Program	Work Category	Timeframe	Focus
<i>Routine Patrol</i>	Standard or Elevated	Annual (until next inspection cycle)	<ul style="list-style-type: none"> MDR encroachment Hazard trees Likelihood of tree failure Priority trees
<i>Hazard Patrol</i>	Standard or Elevated	6-month offset from Routine	<ul style="list-style-type: none"> MDR encroachment Change in condition⁵⁷ Priority trees

Weather Driven Event Procedure (formerly VMOM)

The Weather Driven Event Procedure is a standalone VM program initiated following vegetation-related EPSS outages or ignitions. The program incorporates PIIRs and pre/post

⁵⁶ Programs unaffected by consolidation: Transmission, Vegetation Control, Estimating Arborists, Wood Management

⁵⁷ A change in condition is a tree that will not maintain compliance until next inspection cycle, dead, dying, or defective trees, and/or likelihood of tree failure.



weather-driven event investigations, utilizing Power BI and informed by Extent of Condition (XoC) findings.

ISM VM Targeted Field Inspections

During the current ISM reporting period, the ISM monitored Routine and Second Patrols, FTI, TRI, and VMOM through November 2025, before transitioning observations beginning December 2025 to the 2026 Program Consolidation structure. The ISM conducted field assessments across FTI and VMOM project areas, performed post-event ignition reviews of vegetation-caused PIIRs, and observed PG&E’s implementation of the Defensible Space Program at substation sites. The ISM also conducted site visits with PG&E VM Transmission staff to gain further insight into transmission corridor management, detailed later in this section. The ISM continues to identify hazard trees, trees breaking Minimum Distance Requirements (MDR) encroachment, and ANSI A300/Best Management Practices (BMP) non-compliance.

Table 27: Summary of ISM Field Observations

Attribute	ISM Report 7	ISM Report 8
<i>Hazard Tree & Radial Clearance (Percentage of Assessments)</i>	32 (1.6%)	7 (0.2%)
<i>Observation Trees (Percentage of Assessments)</i>	9 (0.5%)	0 (0%)
<i>Number of Level 1 Assessments</i>	1,993	4,057
<i>Number of Spans Inspected</i>	4,856	1,591
<i>ANSI-A300/BMP non-compliant spans (Percentage of spans)</i>	205 (4%)	145 (9%)

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). AOC designation incorporates historical outage and ignition data, tree species, failure types, and vegetation density. During the current ISM reporting period, the ISM conducted field assessments across seven AOCs in four regions and four counties within PG&E’s electric service territory. These assessments provided additional insight into FTI implementation and the consistency of inspection practices across the service territory.

The ISM observed AOCs within previous fire footprints, areas with low to no tree density, and locations where overhead-to-underground conversion occurred or was in progress.



Figure 23: (Left to Right) FTI No trees observed; FTI Idle line; FTI Active underground conversion area tree removal in process; FTI Area conversion to underground tree removal and pruning completed.

VM targets enhanced inspections using the wildfire risk model, focusing on both vegetation-related risk and high-consequence areas. This strategy prioritizes inspections in locations where vegetation of any density could contribute to a consequential failure; therefore, these areas warrant closer evaluation.

Additionally, PG&E stated that it expects some overlap between elevated inspections and locations that are ultimately hardened or in the process of being undergrounded. Because PG&E considers these as high-risk areas, continued visibility into the risk, particularly vegetation-related risk, remains important until permanent risk-reduction measures are fully implemented. Accordingly, overlapping inspections in these areas are normal and appropriate.

Within FTI projects, VMIs do not re-evaluate or update existing prescriptions unless a change in condition has occurred; previously prescribed work will be completed. PG&E stated there is limited coordination with Electric Operations on underground projects, but they are actively taking steps to increase coordination on underground projects. All overhead facilities will be inspected and trees mitigated on planned inspection cycles until the infrastructure is removed. PG&E noted that tree work associated with system hardening or underground conversion projects is not capitalized.

Vegetation Management for Operational Mitigation

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

Proactive VMOM

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

Consistent with the prior ISM reporting period, VMOM CPZ selection requires that a circuit meet at least one of the following criteria 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.

PG&E reported that Proactive VMOM efforts mitigated approximately 1,824 trees across 674 circuit segments covering roughly 28 miles, from August 2025 through February 2026.

PG&E noted that reported circuit miles for Proactive VMOM reflect the total miles of CPZs where work occurred; mitigations are not necessarily performed along every mile within a CPZ, as efforts may target specific locations. Proactive VMOM reports miles where inspections occurred rather than where trees were identified; the program target is the number of trees mitigated within CPZs. Proactive VMOM is driven by poor-performing circuits on EPSS-enabled devices with increased outages and reliability challenges.

EPSS buffer zones with sectionalizing equipment may be located outside or adjacent to HFTD. Because switching and other operational changes occur in real time, buffer zone boundaries are not adjusted dynamically and may not reflect the current circuit configuration at any given moment. CPZ boundaries are based on customer interruptions, specifically to areas of reoccurring outages, historical outage data, outage types, species failure or types of failure, and species composition within the zone.

VMI inspection criteria considers inventory reduction, but PG&E does not update existing prescriptions unless there is a change in condition; trees prescribed for work will be mitigated.

During the current ISM reporting period, the ISM observed five Proactive VMOM projects across four counties within three regions of PG&E's electric service territory. The ISM continued to observe CPZs with low tree density, inconsistency in prescriptions, and project areas located outside of HFTD.



Figure 24: Proactive VMOM no trees observed

Reactive VMOM

Reactive VMOM projects are initiated following vegetation-related EPSS outages or ignitions. Projects are informed by PG&E's PIIRs, which may result in the development of CAPs. PIIRs



originate at the subject tree and extend at least five spans in all directions from the incident location. Level 2 assessments are performed on trees associated with outages or ignitions, while surrounding trees receive Level 1 assessments. Where additional defects or site conditions are identified on surrounding trees, Level 2 assessments are conducted as warranted.

PG&E reported that PIIRs do not require investigation by International Society of Arboriculture (ISA) Certified Arborists or Tree Risk Assessment Qualification “TRAQ”-credentialed personnel.

Under the consolidated structure, VMOM functions as a standalone program referred to as the “Weather Driven Event Procedure,” integrated into the XoC process. Additional details are provided in the Consolidation of VM Programs section.

Preliminary Ignition Investigation Reports

As referenced in ISM Report 7, PG&E’s Enhanced Ignitions Analysis Group produces the PIIR as its primary deliverable, a comprehensive investigative analysis of the circumstances and suspected root causes of certain in-scope ignitions. Post-event XoC is conducted by VM representatives and encompasses a minimum of five spans from the incident tree in each direction, or further as field conditions warrant, for mitigation purposes.

During the current ISM reporting period, the ISM conducted field assessments on ten PIIRs across eight counties within four regions of PG&E’s service territory. Three PIIRs occurred within previous wildfire footprints.

The ISM identified additional hazard trees within the XoC of two PIIR locations that were not prescribed for work in the system of record at the time of the post-ignition investigation. At locations within previous fire footprints, the ISM observed instances where site dynamics and tree conditions resulting from the initial fire contributed to the failure of incident trees. The ISM also identified trees prescribed for work that did not present strike potential.



Figure 25: (Left to Right) PIIR within burn area and incident tree (photos 1 and 2); PIIR tree marked for removal during XoC with no strike potential; PIIR Hazard Tree not identified during XoC.



PG&E’s post-event investigation reports acknowledged previous burn footprints and the extent of tree damage as likely contributors to incident tree failure. The ISM observed instances of potential oversight by VMIs during subsequent inspections within post-event fire footprints, where VMIs did not account for the full extent of prior wildfire effects and associated tree damage. PG&E noted that not all trees impacted by fire events have observable impacts until approximately 3 years post-fire, which could lead to new prescriptions once assessed during inspection cycles. The ISM will continue monitoring PIIR incidents through field assessments.

Table 28: Summary of PIIR Observations⁵⁸

Interruption Voltage	HFTD	Existing VP	Constraint Y/N	Tree Species	XoC Veg Description of Failure	Date of Ignition	Last Insp. Date Prior to Ignition	Additional Trees Found from PG&E’s XoC
Primary	T-3	None	N	Tan oak	Roots	3/17/2025	11/18/2024	15
Primary	T-3	Yes	N	Bay	Trunk/Decay	7/18/2025	4/15/2025	8-P2
Secondary & Service	T-2	None	N	Monterey pine	Branch no defects	8/22/2025	6/12/2025	0
Secondary	T-3	No Work	N	Oregon White oak	Trunk/Decay	5/31/2025	10/2/2024	1
Primary	T-3	None	N	Douglas fir	Roots	5/5/2025	3/28/2025	0
Primary	T-3	FTI-no work	N	Douglas fir	Trunk/No defects	5/15/2025	4/15/2025	0
Primary	T-3	None	N	Ponderosa pine	Trunk/No defects	7/2/2025	4/18/2025	39
Primary	T-3	No Work	N	Gray pine	Branch/No defects	5/25/2025	1/27/2025	2-P2
Primary	T-2	None	N	Black oak	Trunk/Decay	8/16/2025	7/25/2025	2
Primary	T-2	None	N	Ponderosa pine	Trunk/Decay	6/21/2025	4/17/2025	23

Tree Removal Inventory

PG&E’s TRI program continues to address vegetation risks associated with trees previously identified under the now-discontinued Enhanced Vegetation Management (EVM) program which began with a total of 416,000 trees in inventory. Trees were originally assessed using PG&E’s Tree Assessment Tool (TAT) or through EVM inspections conducted between 2019-2022. The TRI program will continue until inventory trees are mitigated or reassessed, with a completion target of 2030. Under the consolidated structure, TRI inspections will be integrated into Distribution Routine Patrols beginning in the 2026 cycle, with all relevant inspection and tree work data centralized in the OneVM system. PG&E established cumulative mitigation targets of 40,000 trees in 2026, 85,000 in 2027, and 135,000 in 2028 under this integrated

⁵⁸ All PIIR locations impacted an area of 0.25 acres.



approach.⁵⁹

PG&E distributed approximately 192,000 TRI VPs within various VM programs for assessment during associated inspection cycles. Of these, approximately 142,000 trees were inspected between 2023-2024, and 32,500 trees were mitigated under the TRI program in 2024. In 2025, PG&E mitigated approximately 31,311 trees, exceeding the annual goal by 6,630 trees. Since the discontinuation of the EVM program, PG&E mitigated approximately 100,091 trees under TRI-related efforts through the end of February 2026.

Table 29: TRI Program Activity for 2025

TRI Program Summary	Count
<i>TRI Trees removed in 2025 (includes worked through other VM programs)</i>	29,836
<i>TRI Trees removed in 2025 through TRI program</i>	12,433
<i>TRI Trees reassessed by TRAQ Arborist</i>	22,050
<i>TRI Trees removed "TAT Abate" without reassessment</i>	3,114
<i>TRI Trees removed and reassessed by TRAQ Arborist</i>	597

TRI Pilot Project and Marked Tree Inventory (MTI)

As reported in ISM Previous Reports, 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.

The TRI Pilot Project is supported by the MTI initiative, which will continue until all tree work is completed and is 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 prescribed TAT trees located in HFRA, conducted by ISA Certified Arborists with TRAQ credential or Board Certified Master Arborists (BCMAs), until mitigation or formal delisting is completed.

MTI incorporates system-of-record data including GPS coordinates, assessment dates, reasons for delisting, and an auditing process to ensure traceability and verification.

PG&E indicated that data collected through MTI will inform future TRI reassessment efforts and support broader vegetation risk modeling. As of the current ISM reporting period, PG&E confirmed that the TRI Pilot and MTI will not be migrated into One VM due to the short-term nature of both initiatives. Table 30 shows the TRI Pilot Project summary, which reflects approximately 56% of assessed trees recommended for delisting following reassessment.

⁵⁹ PG&E, Consolidated Vegetation Inspection Model: A Risk-Informed Framework for PG&E's 2026-2028 Wildfire Mitigation Plan, December 31, 2025 (page 12).



Table 30: TRI Pilot Project Summary

TRI Pilot Summary	Count
<i>TRI Trees Reassessed by TRAQ Arborist</i>	8,946
<i>TRI Trees Removed (TAT Abate without reassessment)</i>	525
<i>TRI Trees Removed after Reassessment by TRAQ Arborist</i>	752
<i>TRI Trees Recommended for Delist after Reassessment</i>	5,032
<i>TRI Trees Pruned</i>	240
<i>TRI Trees Removed by other programs at time of reassessment by TRAQ Arborist</i>	2,167

Transmission Vegetation Management

During the current ISM reporting period, the ISM conducted a site visit with PG&E’s VM Transmission staff to gain further insight into the processes and procedures governing management of transmission corridors. The review encompassed NERC and Non-NERC regulated facilities, BMPs, and the application of Integrated Vegetation Management (IVM) principles. VM Transmission is not affected by the 2026 program consolidation.

PG&E’s VM transmission program is staffed by one Director, one Senior Manager, two regional managers, and five VM Supervisors system wide. VM Supervisors are responsible for daily operations, safety, constraints, VMI oversight, and crew productivity. PG&E conducts monthly benchmarking training in both field and office settings for internal and contracted resources. QA/QC activities monitor VMIs and crews, with monthly follow-up on findings and coaching opportunities for corrective action.

PG&E’s transmission system includes approximately 18,000 line-miles, of which approximately 5,600 miles are located within HFTD. PG&E utilizes LiDAR technology for transmission patrols. All corridor routes are inspected once per year during a routine patrol conducted in fall/winter. A hazard tree/grow-in patrol covering the approximate 5,600 HFTD miles is conducted at mid-cycle during summer. A third patrol utilizing orthoimagery is scheduled near-end of summer to detect loss of chlorophyll on trees. Station-to-station patrols are performed by LiDAR flights, while ground patrols are initiated specifically to identify and confirm Points of Interest (POIs) identified by LiDAR. PG&E reported that it utilized LiDAR in VM work planning for approximately twelve years and that the program will continue to evaluate other remote sensing technologies.

PG&E applies ISA BMPs and IVM principles on transmission corridors. IVM principles are incorporated within work scopes where regulation and permitting requirements allow for their use. Herbicide applications are limited and primarily conducted via backpack techniques, with goals to reduce costs, reduce fuel loading, clear tower bases, decrease undesirable species, and enhance low-growing plant communities. PG&E applies wire zone/border zone BMPs in the clearing of transmission corridors.



Figure 26: Non-PG&E Transmission Line (left) PG&E Transmission Line (right) note fuel density on left

PG&E implemented a Right-of-Way (ROW) Expansion Program in 2020, establishing goals to reclaim corridor width by removing incompatible species from the wire zone. PG&E states since inception it completed approximately 1,494 miles through February 2026. Clearing width is established by voltage (120 feet for 230 kV lines) or by defined easement. PG&E partners with United States Forest Service (USFS), Bureau of Land Management (BLM), Sierra Pacific Industries (SPI), and CAL FIRE on ROW expansion projects; however, no cost-sharing or grant funding is available to offset PG&E's expenses. PG&E noted that additional program benefits include creation of firebreaks, safer work areas for crews, improved access, and staging capacity for emergency operations. The ROW Expansion Program is a one-time clearing effort to re-establish the corridor; ongoing maintenance is conducted only on ROWs occupied by energized facilities.

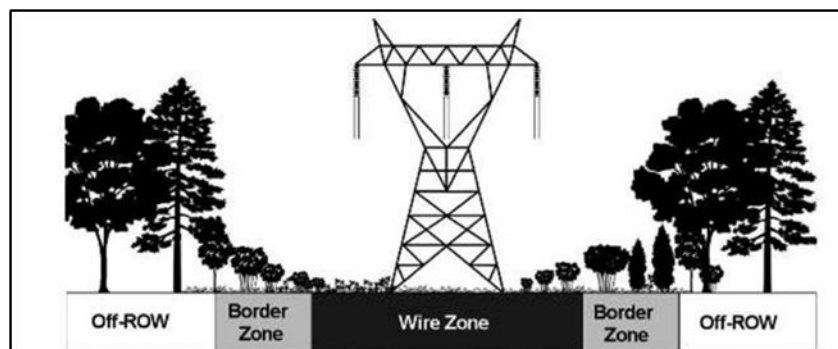


Figure 27: Wire Zone/Border Zone BMP Diagram

Substation and Switchyard Defensible Space

During the current ISM reporting period, the ISM visited four distribution substation sites to observe PG&E's Defensible Space inspection procedure, as outlined in the current WMP commitments. The procedure applies to transmission and distribution substation facilities and power generation switchyards.

Defensible Space procedures address potential fuel conditions requiring mitigation in accordance with PRC 4291. PG&E evaluates fuel conditions to confirm that acceptable



vegetation thresholds are maintained to reduce the potential for ignitions. Where conditions are identified, PG&E performs mitigation activity to address declining, dying, and dead vegetation. Ongoing maintenance includes mowing to reduce flash fuels and pruning to reduce ladder fuels.

PG&E's depth-in-defense strategy establishes a buffer distance between electrical infrastructure and surrounding vegetation to enhance firefighting capabilities, prevent the spread of ignitions from substations and switchyards, and protect facilities against incoming fire.



Figure 28: (Left to Right) Recent removal of vegetation to create buffer, erosion occurred; Vegetation buffer created wood framing on substation fence and wooden signage; Hardscape/Fencing, ladder fuels right side of entry drive; Tall vegetation removed, conversion to turf for buffer zone.

The Natural Resource Management (NRM) group began managing the execution of inspections and mitigations, under “Electric Substation and Power Generation Powerhouse and Switchyard Defensible Space” (LAND-5201P-01) procedure, on behalf of Electric Operations since 2018. The NRM group is a separate entity and operates outside of PG&E's VM Department. This program was initially incorporated within the Wildfire Safety Inspection Program (WSIP) and currently is in the 2026-2028 WMP targets. NRM manages three WMP commitments; Distribution Substations (VM-05), Transmission Substations (VM-06), and Powerhouse and Switchyards (VM-07) within HFTD and HFRA.

Constraints Process

As reported in ISM Previous Reports, PG&E's VM constraints process is designed to identify and manage conditions that prevent timely execution of prescribed vegetation work. A constraint is initiated when a VMI creates a prescription, or shortly thereafter, and remains active until resolved or until a change in condition escalates the priority of the work. PG&E leadership indicated that a change in condition to Priority 1 or Priority 2 prompts expedited resolution. PG&E maintains five constraint categories: Biological & Cultural, Environmental Permitting, Encroachment Permitting, Customer, and Operational.

During the current ISM reporting period, the ISM reviewed PG&E's constraint tracking and resolution practices, including coordination between the Constraints Management Team and PG&E's operational regions. As of 2/5/2026, PG&E's active constraint inventory totaled 167,185.5 constraints across all VM programs. Environmental Permitting represents the largest category at 58,098 constraints (35% of the total), followed by Operational at 38,944



(23%) and Encroachment Permitting at 36,225.5 (22%). Table 31, Table 32 and Figure 29 detail active constraints by program, age, and annual creation and resolution activity from 2023 through 2025.

Table 31: Active Constraints by Program and Constraint Group as of 2/5/2026⁶⁰

Constraint Group ⁶¹	FTI	Other ⁶²	Distribution Routine & 2nd Patrol	Transmission Routine & 2nd Patrol	TRI	VMOM	Grand Total
Biological & Cultural	555	7,335	3,217	1,378	3,812	12	16,309
Customer	567	2,194	5,765	292	8,748	43	17,609
Encroachment Permitting	1,151	713	30,486.5	318	3,504	53	36,225.5
Environmental Permitting	4,167	6,260	30,796	1,013	15,054	358	58,098
Operational (Elec. Ops)	635	12,477	4,418	809	20,476	129	38,944
Grand Total	7,525	28,979	74,682.5	3,810	51,594	595	167,185.5

Of the 167,185.5 total active constraints, approximately 49,026 (roughly 29%) are fewer than 60 days old; however, approximately 40,606 constraints (roughly 24%), have been active for more than 360 days. PG&E noted that the majority of approximately 86% of constraints aged over 360 days are associated with TRI and are not tied to Routine or Hazard patrol programs.

Table 32: Active Constraints by Constraint Group and Age as of 2/5/2026

Age	<60	60-89	90-119	120-239	239-360	>360	Grand Total
Biological & Cultural	3,629	137	627	2,051	1,007	8,858	16,309
Customer	4,291	885	1,212	2,062	1,776	6,763	17,609
Encroachment Permitting	12,543	2,595	3,464	9,550	3,619	4,454.5	36,225.5
Environmental Permitting	10,068	4,556	4,007	23,618	5,184	10,665	58,098
Operational (Electric Ops)	17,865	1,868	2,065	6,288	966	9,865	38,994
Grand Total	49,026	10,043	11,392	43,577	12,542	40,605.5	167,185.5

Annual constraint data from 2023 through 2025 show increasing constraint creation that outpaced resolution, though 2025 represents a reversal at the aggregate level. Total constraints created grew from approximately 229,000 in 2023 to 358,000 in 2025, an increase of approximately 57% over three years. Over the same period, constraints resolved grew from

⁶⁰ The decimals in this table represent units of “brush” trees in constrained status.

⁶¹ Biological & Cultural (riparian areas boarding bodies of water, bird nests, cultural resources if tree work is within 100 ft), Customer (concerns or refusal of tree work), Encroachment (Caltrans, Railroads, City/County), Environmental (agency managed lands, wildlife and vegetation habitat impact issues/concerns involving tree work), Operational (tree work requiring PG&E Electric Operations assistance)

⁶² PG&E states that reporting improvements were made to better isolate the TRI constraints and which were previously included in the “Other” Program.



approximately 132,000 in 2023 to 369,000 in 2025, an increase of approximately 180%. In 2025, resolved constraints exceeded created constraints for the first time in the three-year period, producing a net resolution of +10,928 at the system level. Figure 29 below shows the year-over-year creation and resolution of constraints.

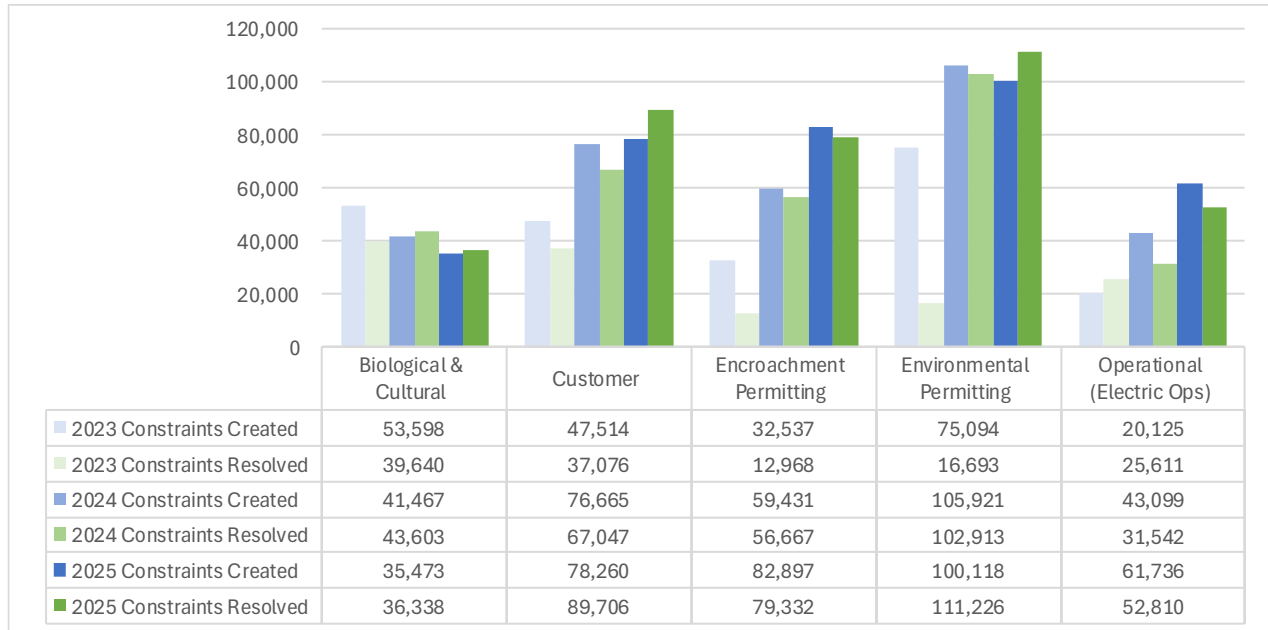


Figure 29: Constraints Created and Resolved by Year (2023-2025)



GAS OPERATIONS OBSERVATIONS

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 8 is directed toward five major categories: (1) Safety Culture Surveys and Workforce Engagement Initiatives (2) Gas Business Planning, (3) Gas Transmission & Distribution Planning, (4) Damage Prevention, and (5) Kettleman Corrective Action Status.

SAFETY CULTURE SURVEYS AND WORKFORCE ENGAGEMENT INITIATIVES

PG&E engaged the National Safety Council (NSC) to administer Safety Barometer employee perception surveys to Gas Operations personnel in 2020, 2022, and 2025. The NSC is a nonprofit safety advocacy organization with the mission to eliminate preventable injuries and deaths in the workplace and everyday life. NSC conducted employee safety perception surveys for over 30 years and maintains a benchmarking database of approximately 1,400 organizations, which allows PG&E to compare their safety culture performance against industry peers. The NSC database includes millions of employee responses from businesses across various countries and industries, including utility, chemical, food, construction and others. Respondents to the NSC surveys tend to be high performing businesses with a focus on safety culture.

These surveys assess employee perceptions of safety culture through responses to 50 statements addressing safety practices across six categories: Management Commitment, Supervisor Engagement, Employee Involvement, Safety Support Activities, Safety Support Climate, and Organizational Climate. Responses are benchmarked against NSC’s database and are given percentile scores for each question, category, and an overall response rank.

Across the three survey cycles, PG&E’s overall percentile ranking improved in each category. The chart below summarizes the overall percentile scores and category-level results for the three surveys.

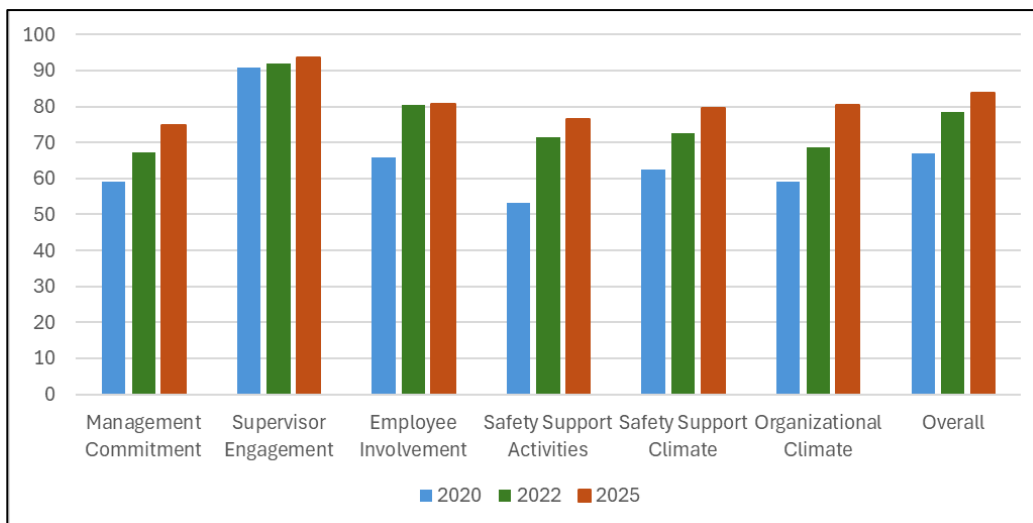


Figure 30: PG&E's Percentile Score Trends



As shown in Figure 30, the results indicate continuous improvement across all six safety culture categories between the 2020 and 2025 surveys. Supervisor Engagement remained the highest-scoring category in each survey cycle. Some categories that showed notable improvement over the three survey periods include Management Commitment and Organizational Climate.

The survey results identify areas of strength and areas of improvement. NSC notes that more neutral scores may reflect limited employee knowledge or awareness of programs rather than deficiencies in the programs themselves. The survey results provide insight into PG&E management practices where additional communication, engagement, or reinforcement may be warranted. PG&E uses these surveys to identify two to three focus areas requiring improvement, and to create and implement action plans to address related areas for improved communication, employee engagement, and operational initiatives.

Following the 2020 survey, PG&E initiated numerous initiatives to strengthen employee engagement within safety culture development. Among these multiple initiatives were employee-led Gas Safety Culture Guidance Teams, or “Safety Culture Villages.” These cross-functional teams include employees and management, and are intended to facilitate discussion of safety culture topics and drive improvements at the local level.

According to PG&E, the Gas Safety Culture Villages take action to address local issues identified using culture tools including Cycle of Mistrust and Iceberg. Examples discussed with the ISM include efforts to increase awareness of some safety procedures such as wearing personal protective equipment, reinforcing behaviors for reporting hazards and near misses, and promoting open dialogue regarding safety concerns.

PG&E indicated that the Safety Culture Villages are intended to operate as a bottom-up, culture based continuous improvement rather than a one-time program. The company indicated that Safety Culture Villages grew over time organically, with employees showing significant interest in starting a local village when they learned more about the program. In addition to the Safety Culture Villages, ongoing initiatives continue to address employee engagement and additional safety improvements.

GAS BUSINESS PLANNING

PG&E manages gas infrastructure investment through a framework in which Asset Family Owners (AFOs) are responsible for developing AMPs, identifying asset risks, and translating investment needs into work programs. Planning occurs across three layers: rate case planning, annual investment cycles, and execution-level planning. The Vice President of Engineering for PG&E’s gas organization provides governance oversight of the asset management system and participates in forums including risk committee meetings.

Business Deployment Process

Capital allocation across PG&E’s operating organizations is managed through the Business Plan Deployment (BPD) process. Enterprise wide capital and expense targets are established by executive leadership and allocated across business units, including electric and gas operations (Energy Delivery). Within the gas organization’s allocation, AFOs evaluate a bottoms-up



forecast, and determine which risks to mitigate and which work programs to fund. For PG&E, compliance obligations are a non-negotiable priority. Data-driven compliance programs are funded first, with remaining dollars allocated across other risk mitigation and reliability programs.

PG&E reported that gas and electric work programs are collectively reviewed by Asset Family Owners (AFOs) to assess highest-priority program risk mitigations proportional to planned electric or gas program funding. Gas AFOs and PG&E executive leadership may collectively agree to reprioritize originally planned gas program work, in order to fund higher-priority work in other functional areas. PG&E reported that there are no enterprise limitations to prevent reprioritization of allocated program funds moving between gas and other functional organizations or work programs within PG&E; however, underlying gas or electric program revenue streams may represent different rate classes which may introduce regulatory considerations.

Risk Management

PG&E reported that work program risk categories evaluated within its enterprise risk management standard process include safety, financial, environmental, and reliability risk, with safety risk carrying significantly greater weight than reliability risk. When tradeoffs must be made, PG&E reports that reliability considerations can be modified to ensure all safety obligations are fulfilled.

During the 2024 rate case cycle, the ISM observed that the adjustment to Gas Operations expense work program funding for gas distribution and gas transmission & storage represents an approximate 28% and 23% reduction, respectively compared with General Rate Case (GRC) adopted funding. Capital work program funding for gas distribution was approximately 2% over for gas distribution and 14% under compared with GRC.⁶³

PG&E also noted that AFOs have not applied common risk tolerance metrics to the work program risk allocation funding review process. PG&E acknowledges that reprioritizing work program funds across functional areas may result in an increase of specific program risk, while reducing overall enterprise risk.

PG&E also reported that gas asset unplanned downtime and customer interrupted minutes are not currently incorporated as inputs into their enterprise risk, nor monitored or reported as part of work program risk reduction analysis presented to senior leadership. PG&E did indicate that counts of gas customer outages are reflected on the consequence side of its loss-of-containment risk models.

GAS TRANSMISSION & DISTRIBUTION PLANNING

PG&E is required to file an annual RSAR with the CPUC. The RSAR provides a comparison of actual recorded expenditures compared with adopted work program funding from the most recent GRC cycle across safety, reliability, integrity management, and operational programs.

⁶³ PG&E's 2024 Risk Spending Accountability Report: Table 1-1 lines 1 & 2 and Table 1-2 lines 1 & 2.



Where actual spending differs materially from adopted GRC program funding, PG&E is required to provide explanations for program funding variances documented within the RSAR.

Gas Transmission and Storage (GT&S) was incorporated into PG&E’s GRC framework with the 2023 GRC cycle. Prior to 2023, GT&S revenue requirements were governed under a separate GT&S rate case proceeding and were not subject to GRC-based RSAR reporting. As a result, comparable RSAR data for GT&S are currently available for 2023 and 2024 only. For expense spending over those two years combined, PG&E reported approximately \$894.9 million in actual GT&S expense, which reflected a funding variance of approximately \$263.6 million, or roughly 22.8 percent below adopted levels as shown in Table 33. Interviews with PG&E and explanations contained with the 2024 RSAR attribute the variance to changes in inspection timing, lower than anticipated transmission leak repair and direct examination dig volumes, higher electricity costs and usage at electrically powered gas compressor stations, and reprioritization of work programs in response to enterprise-level financial targets.

Table 33: Gas Transmission and Storage RSAR Expense Spending Summary (Thousands of Dollars)

Year (GRC Cycle)	Category	Adopted (\$K)	Actual (\$K)	Variance (\$K)	Variance (%)
2023 (2023 GRC)	Gas T&S	\$575,614	\$471,341	\$104,273	18.1%
2024 (2023 GRC)	Gas T&S	\$582,924	\$423,628	\$159,296	27.3%
2023-2024 Combined		\$1,158,538	\$894,969	\$263,569	22.8%

For capital spending during 2023 and 2024 combined, PG&E reported approximately \$1.4 billion in actual GT&S capital spending, which reflected a funding variance of approximately \$227.5 million, or roughly 13.7% below adopted levels as shown in Table 34. PG&E’s RSAR explanations attribute the variance to changes in accounting guidance for previously tested Non-Integrity Management Driven footage and their respective costs, a lower volume of Hydrostatic strength testing needed and project cancellations.

Table 34: Gas Transmission and Storage RSAR Capital Spending Summary (Thousands of Dollars)

Year (GRC Cycle)	Category	Adopted (\$K)	Actual (\$K)	Variance (\$K)	Variance (%)
2023 (2023 GRC)	Gas T&S	\$830,998	\$683,509	\$147,489	17.7%
2024 (2023 GRC)	Gas T&S	\$835,756	\$755,721	\$80,035	9.6%
2023-2024 Combined		\$1,666,754	\$1,439,230	\$227,524	13.7%

Additional RSAR spending observations are discussed in the section entitled Work Activity Trends below.

Gas Transmission Infrastructure and Asset Condition

PG&E’s transmission system includes approximately 7,000⁶⁴ miles of pipeline, with approximately 1,500 miles located within federally defined High Consequence Areas (HCAs). The backbone system transports gas to California customers from receipt points near Malin, Oregon and Topock, Arizona. The Redwood Path (Oregon interconnection) provides

⁶⁴ <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>,



approximately 70% of PG&E’s transmission supply capability and the Baja Path (Arizona interconnection) provides the remaining approximately 30%, with a firm design capability of approximately 945 million standard cubic feet per day (MMcfd) for the Baja system and approximately 2,200 MMcfd for the Redwood system. During the current ISM reporting period, the ISM’s review of gas transmission infrastructure focused in particular on the asset condition and capital investment needs of compression facilities along the Baja Path, the regulatory framework governing significant gas infrastructure investments, and the work activity and spending trends that inform PG&E’s ability to maintain and replace aging transmission assets over time.

General Order 177 and Gas Infrastructure Investment

The CPUC adopted General Order 177⁶⁵ (GO 177) in December 2022 to establish application, notification, and reporting requirements for significant gas infrastructure investments. Under GO 177, gas utilities are required to obtain a Certificate of Public Convenience and Necessity (CPCN) before commencing construction of any gas project with estimated costs exceeding \$75 million, or any project located within 1,000 feet of a sensitive receptor that requires an air quality permit. The CPCN process requires the utility to demonstrate project necessity, evaluate non-pipeline alternatives, assess environmental impacts, and provide public notice. GO177 provides a limited exemption from the CPCN requirement for emergency projects necessary to prevent conditions that could impact safe and reliable gas supplies, consistent with California Environmental Quality Act (CEQA) emergency project definitions.

GO177 requires utilities like PG&E to file an annual report identifying planned gas infrastructure investments over a ten-year forecast period that meet or approach the CPCN threshold. PG&E’s GO177 annual report,⁶⁶ filed February 28, 2025, identifies five projects in its forecast period, summarized in Table 35 below. Collectively, these projects represent an estimated capital investment of approximately \$733 million, and address aging compressor stations, pipeline integrity upgrades, and terminal rebuilds across PG&E’s gas transmission backbone.

Table 35: PG&E Planned Gas Infrastructure Projects — GO 177 Annual Report (As of February 28, 2025)

No.	Project	Location	Est. CapEx	Est. In-Service
1	ILI Upgrade	Napa/Sonoma County	\$64.4M	May 2025
2	Terminal Station Rebuild	Contra Costa County	~\$212M	2026–2032 (phased)
3	Compressor Station Electrical Upgrades	San Bernardino County	\$93.5M	February 2027

⁶⁵ https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/general-orders/go_177_gas_infrastructure.pdf

⁶⁶ PG&E’S (U 39 G) Annual Report of Planned Gas Investments - In Compliance with General Order 177, February 28, 2025.



4	Compressor Replacement	Contra Costa County	\$75.6M	August 2029
5	Compressor Station Rebuild	San Bernardino County	~\$288M	TBD
Total			~\$733M	

The scale of this investment pipeline reflects the cumulative effect of aging infrastructure replacement across PG&E’s gas transmission system. Several of these projects address equipment that has reached or significantly exceeded its intended service life, with components described in PG&E’s project documentation as obsolete, approaching failure, or no longer supportable by original equipment manufacturers. The Terminal Station rebuild (No.2), for example, involves a major transmission terminal where equipment obsolescence and age pose ongoing reliability risks, with a full replacement program extending through 2032. The Compressor Station rebuild (No.5), PG&E’s single largest identified GO177 project at approximately \$288 million, would replace nine reciprocating compressor units installed in the early 1950s, all operating well beyond design life.⁶⁷ Compressor Station No.5 project schedule remains to be determined, in part because the Environmental Protection Agency (EPA) Good Neighbor Plan regulation that accelerated its need is subject to legal challenges.

Compressor Station No.3 Emergency Project

Compressor Station No.3, located on PG&E’s Baja Path backbone transmission lines 300A and 300B in San Bernardino County, is reported to operate almost continuously using up to twelve reciprocating compressor units, ten of which were originally installed between 1951 and 1953. The station provides approximately 19% of the total Baja Path compression horsepower and is reported by PG&E personnel to be critical to reliably meet its system-wide demand on a “1-in-10-year peak winter day”, a condition that would require the Baja Path to operate near its maximum capacity of 888 MMcfd.

In April 2025, PG&E filed an application with the CPUC (Application No. 25-04-004) for a CPCN to replace the station’s electrical distribution equipment, including switchgear, motor control centers (MCCs), and load centers, which reached the end of its useful life. The projected cost of the project was \$93.5 million, triggering the GO177 CPCN requirement. A Commission decision on the CPCN was expected in the third or fourth quarter of 2026.

PG&E reported that the pace of equipment failures at Compressor Station No.3 accelerated materially during the summer and fall of 2025.⁶⁸ For example, one generator failed due to an obsolete component and went out of service. On July 20, 2025, a failed breaker on a motor controller caused an unplanned trip of the entire station. By late 2025, PG&E had only three

⁶⁷ FERC’s Cost-of-Service Rates Manual uses a 25-year depreciable life for natural gas pipeline compressor station facilities. While robust maintenance programs can extend the life of compressor stations, units installed in the early 1950s would be approximately three times their implied design life. FERC Cost-of-Service Rates Manual, Federal Energy Regulatory Commission, available at <https://www.ferc.gov/sites/default/files/2020-08/cost-of-service-manual.pdf>.

⁶⁸ Information presented to the ISM during site visits to Compressor Station No.3 and No.5 in 2025.



operational generating units, with limited spare parts available for critical components, some of which had no direct replacement due to obsolescence. PG&E determined that the station's electrical distribution equipment might not remain functional through the CPCN review period, and that an additional unreparable failure could result in loss of gas supply along the Baja Path.

On January 20, 2026, citing a G0177 exemption for emergency projects necessary to prevent conditions that could impact safe and reliable gas supplies, PG&E commenced the Compressor Station No.3 upgrade project. On February 4, 2026, PG&E submitted an advice letter notifying the CPUC of the claimed exemption and submitted a motion to withdraw its pending CPCN application.⁶⁹ The project is currently underway, with PG&E expecting construction completion by January 2028. PG&E reported that temporary natural gas generators have been deployed on site to power the station's ancillary support systems during construction.

Interviews with PG&E personnel indicated that the pace of equipment deterioration at Compressor Station No.3 did not allow sufficient time for the standard CPCN review process to be completed before construction became necessary. As noted in the site visit observations and work activity trend analyses that follow, asset age and deferred investment are recurring themes across PG&E's gas transmission infrastructure.

Baja Path Compressor Stations: Site Visit Observations

The ISM conducted site visits to Compressor Stations No.3 and No.5 along the Baja Path during the current ISM reporting period, both of which are identified in PG&E's G0177 annual report as requiring significant capital investment. The ISM observed that both stations contain a combination of legacy and modern equipment. As noted above, a component is considered obsolete when the original equipment manufacturer (OEM) no longer provides support or when spare parts are scarce or unavailable; once obsolete, equipment is more vulnerable to operational failures and longer repair times.

At Compressor Station No.3, multiple integral reciprocating compressor units were originally installed in 1951, with additional units added through 1967, ranging from approximately 2,400 to 7,250 horsepower. Per the Compression and Processing Asset Management Plan (CP AMP), the station's gas compressors, control systems, and electrical systems are aging, and in some cases, obsolete. Control systems associated with the unit compressors require upgrades due to reliability concerns, with control panel upgrades planned for 2025–2027. The station currently operates with a hybrid emergency shutdown (ESD) system; a standalone project to convert to a fully electrical ESD configuration has been identified but is not currently funded. As described in the preceding section, the Compressor Station No.3 electrical upgrade project is currently underway with a target completion date of January 2028. Photos of the Compressor Station No.3 are shown in Figure 31.

⁶⁹ PG&E's (U 39 E) Motion to Withdraw Application No. 25-04-004, Dated February 4, 2026. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K280/602280052.PDF>



Figure 31: Photos of Compressor Station No.3

At Compressor Station No.5, multiple compressor units date to 1951 installations, and are rated at approximately 3,500 horsepower each. A capital project completed in 2022 replaced the station control system and addressed electrical improvements to resolve issues associated with previously obsolete control equipment. As identified in Table 35 (No.5) above, a full station rebuild is listed in PG&E's GO177 annual report at an estimated cost of approximately \$288 million, with a planned in-service date still to be determined pending resolution of the EPA Good Neighbor Plan litigation. Photos of Compressor Station No.5 are shown in Figure 32.



Figure 32: Photos of Compressor Station No.5

As described in PG&E's Asset Management Plan, across the compression asset family, certain programmable logic controllers (PLCs) are obsolete, with a replacement program expected to be proposed in a future rate case. Spare parts for some installed gas generators are increasingly difficult to procure due to limited OEM and aftermarket support. While PG&E may have some spares, they are no longer available from OEMs, and must be obtained from cannibalizing other station equipment or ordered from resellers. These conditions, taken together with the GO177 project pipeline described above, are consistent with the work activity trends and spending patterns discussed in the sections that follow.

Gas Transmission & Storage Capital Investment

Within the overall Gas Transmission & Storage capital programs, the ISM reviewed spending under GT&S Station Reliability (MWC 76 in the 2024 RSAR), which covers capital investment in PG&E's compressor stations, metering and regulating stations, gas terminals, and



underground storage facilities. This program is related to the asset condition concerns noted by PG&E at Compressor Station No.3 and No.5 (above). For the 2023-2024 GRC cycle to date, MWC 76 recorded actual capital spending of approximately \$313.9 million against adopted levels of approximately \$381.9 million, an underspend of approximately \$68 million or 18% over the two-year period (2024 RSAR Table 2-8, row 12).

Within MWC 76, the ISM noted several program-level observations particularly relevant to compressor station reliability. Routine station capital work (MAT 76N), which funds a broad range of “find and fix” projects at compressor and processing facilities, recorded actual spending of approximately \$75.4 million against an adopted two-year level of approximately \$116.7 million, an underspend of approximately 35% (2024 RSAR Table 2-10, row 95). PG&E’s RSAR explanation attributed this variance to gas prioritization in support of higher risk and compliance work. Compressor control upgrades (MAT 76T), which cover control system modernization at compressor stations, were underspent by approximately 16% over the two-year cycle (2024 RSAR Table 2-10, row 100) and recorded zero completed station upgrades in 2024 against an adopted target of one; PG&E cited delays attributable to the CPCN permit approval process, directly referencing the GO177 regulatory timeline discussed above. Electrical upgrades at Compressor Station No.3 and No.5 (MAT 76P) were on track in aggregate, though the Compressor Station No.3 project ultimately transitioned to an emergency exemption as described in the preceding section.

The RSAR data for MWC 76 is consistent with the broader pattern observed across GT&S capital spending: PG&E has not fully executed adopted investment in station reliability, with routine and planned maintenance work deprioritized in favor of compliance-driven programs. PG&E’s RSAR explanations cite gas prioritization decisions as a recurring factor across multiple station reliability subprograms, underscoring the funding issues identified in the gas business planning discussion earlier in this section.

Work Activity Trends

The ISM reviewed work activity trends across five program areas: leak repair, preventative maintenance, atmospheric corrosion inspection and repair, and meter protection. This analysis drew on multiple sources, including MAT-coded work activity data from PG&E’s RSAR tables covering 2019 through 2024, responses to ISM data requests, PG&E interviews, and publicly available Pipeline and Hazardous Materials Safety Administration (PHMSA) data. The analysis examined work volume and unit cost trends within each category over the review period. Declining work volumes within a given program may reflect a range of factors including reduced underlying risk exposure, operational efficiencies, or changes in inspection findings as well as reprioritization in response to resource constraints. For instances where unit costs increased and total spending remained relatively stable, PG&E indicated that fewer work units are completed within the same funding level. The following sections present the ISM’s observations across each program area.

Leak Repair Trends and Outstanding Leak Backlog

Leak repair programs address the identification and remediation of leaks across PG&E’s gas distribution systems. These activities include main leak repairs, service leak repairs both above and below ground, repairs associated with excavation damage and rechecks performed to



confirm the condition of previously identified leaks. Leaks are classified by grade based on the level of hazard they present in accordance with PHMSA requirements, with Grade 1 leaks representing an immediate hazard requiring emergency response, Grade 2 leaks representing non-immediate hazards requiring scheduled repair, and Grade 3 leaks representing non-hazardous conditions that require periodic monitoring and reevaluation. Because these activities are often triggered by field conditions but executed within resource constraints, the volume of open non-hazardous leaks awaiting repair can increase if repair activities are postponed or if available repair resources are insufficient to address all identified work.

MAT categories for Main Leak Repairs (FIG) and Below Ground Service Leak Repairs (FIP) show steady work volumes whereas Above Ground Service Leak Repairs (FIH) show declining work unit volumes from 2019 to 2024, while cost per unit has increased over the same period. As shown in Table 36, the number of main leaks (MAT FIG) and below ground service leaks (MAT FIP) repaired remained relatively steady from 2,144 and 4,537 in 2019 to 2,459 and 4,024 in 2024 respectively, while cost per unit increased from \$7,729 to \$13,307 and from \$3,392 to \$6,918 over the same period due to paving, materials, and internal labor. Above Ground Service leak repairs under MAT FIH declined more sharply, from 5,087 above-ground repairs in 2019 to 1,726 in 2024, with cost per unit increasing from \$273 to \$1,560 primarily from labor cost increases in addition to materials and paving cost increases.⁷⁰

Table 36: Loss of Containment on Gas Distribution Main or Service (costs shown in Thousands unless otherwise stated)

MAT		2019	2020	2021	2022	2023	2024
FIG⁷¹	<i>Adopted Costs</i>	\$20,803	\$19,755	\$20,331	\$20,555	\$35,096	\$35,680
FIP⁷²	<i>Adopted Costs</i>	\$18,073	\$13,936	\$14,343	\$14,501	\$31,649	\$32,177

⁷⁰ PG&E reported the main drivers for the increase in unit cost for above ground service leak repairs from 2019-2025 were labor, material and paving cost increases. PG&E reports that labor accounts for 35 percent of the total cost increase whereas materials and paving account for 13 percent and 6 percent respectively. There were also changes to the Leak Grading Procedure that shifted the above ground riser thread gradable leaks to MAT FIS that could require 2-man crews.

⁷¹ MAT FIG – Main Leak Repair – Expense repair of non-dig-in leaks less than 100 feet on any distribution main and appurtenances (flanges, valves, etc.). Includes leak pinpointing. Includes repair of service leak by replacing a portion of main (100 feet or less). Includes repair of leak on existing cut-off service tee (24 inches or less). Does not include: If a suspected leak is excavated and downgraded to a 3 or 0 that will not be repaired, non-PG&E gas, and if service tee is cut off within 12 inches of main and no service exists. Below ground Grade 3 leak repairs are recorded under Leak Abatement MAT LWG. This program relates to safety and/or reliability and/or maintenance as it involves expense repairs of non-dig-in leaks less than 100 feet on any distribution main and appurtenances (flanges, valves, etc.). It includes leak pinpointing, repair of service leak by replacing a portion of main (100 feet or less), and repair of leak on existing cut-off service tee (24 inches or less). (From PG&E’s RSARs Gas Distribution MAT Descriptions)

⁷² MAT FIP – Service Leak Repair, Below Ground – Leak pinpointing and repair of non-dig in leak on below ground section of any service (includes curb valves) from tee to where riser breaks ground. Includes: (1) above ground leak that requires below ground repair (i.e., must replace section of below ground pipe or riser); and (2) riser replacement including section of below ground service. Does not include if a suspected leak is excavated and downgraded to a 3 or 0 or non-PG&E gas. Below ground Grade 3 leak repairs are recorded under Leak Abatement



FIH⁷³	<i>Adopted Costs</i>	\$4,786	\$5,713	\$5,879	\$5,944	\$4,098	\$4,166
FIG	<i>Actual Costs</i>	\$16,570	\$26,022	\$33,469	\$40,283	\$35,104	\$32,722
FIP	<i>Actual Costs</i>	\$15,388	\$22,731	\$26,238	\$29,111	\$27,893	\$27,837
FIH	<i>Actual Costs</i>	\$1,389	\$4,101	\$3,234	\$3,106	\$2,699	\$2,693
FIG	<i># of main leaks repaired</i>	2,144	3,211	3,719	3,526	2,592	2,459
FIP	<i># of service leak repairs, below ground</i>	4,537	6,092	5,604	4,746	4,509	4,024
FIH	<i># of service leak repairs, above ground</i>	5,087	9,036	6,147	3,911	2,044	1,726
FIG	<i>Cost/Unit (\$/repair)</i>	\$7,729	\$8,104	\$9,000	\$11,425	\$13,543	\$13,307
FIP	<i>Cost/Unit (\$/repair)</i>	\$3,392	\$3,731	\$4,682	\$6,134	\$6,186	\$6,918
FIH	<i>Cost/Unit (\$/repair)</i>	\$273	\$454	\$526	\$794	\$1,320	\$1,560

The presence of outstanding leaks does not indicate regulatory non-compliance, as leak classification and repair timelines are governed by the grade of the leak as governed by PHMSA; however, the volume and trend can provide an indicator of repair work remaining in the system. PG&E reported the average days to repair Grade 2 leaks increased from 113 days in 2023 to 119 days in 2024, and the number of Grade 2 leaks open more than 180 days increased from 180 to 305 over the same period. The open, end-of-year leaks are shown in Figure 33 for 2023 and 2024.

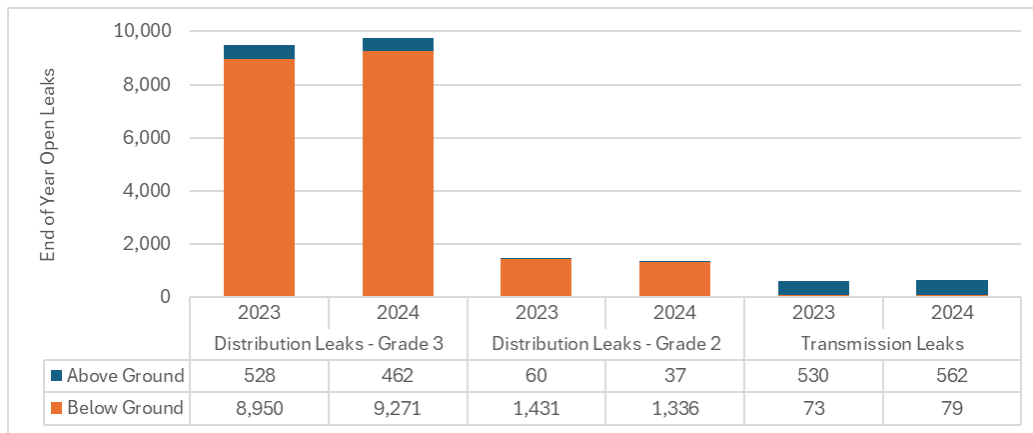


Figure 33: End-Of-Year Open Leaks (2023 and 2024)

MAT LWH. This program relates to safety and/or reliability and/or maintenance as it involves leak pinpointing and repair of non-dig in leak on below ground section of any service (includes curb valves) from tees to where risers breaks ground. It includes: (1) above ground leak that requires below ground repair (i.e., must replace section of below ground pipe or riser); and (2) riser replacement including section of below ground service. (From PG&E’s RSARs Gas Distribution MAT Descriptions)

⁷³ MAT FIH – Gas Service Leak Repair, Above Ground – Leak pin-pointing and repair of non-dig-in leaks below the service valve on the above ground portion of the service. Does not include: If a suspected leak is excavated and downgraded to a 3 or 0 that will not be repaired, or non-PG&E gas. This program relates to safety and/or reliability and/or maintenance as it includes leak pin-pointing and repair of non-dig-in leaks below the service valve on the above ground portion of the service. (From PG&E’s RSARs Gas Distribution MAT Descriptions)



Preventive Maintenance Work Volumes

Preventive maintenance programs for gas mains and other infrastructure are designed to identify and address developing asset conditions before they result in operational failures or safety incidents. These programs are typically performed on defined recurring cycles and represent a category of proactive work that is distinct from emergency or corrective repairs. Because preventive maintenance activities generally do not address an immediate regulatory compliance obligation, they are among the work programs most susceptible to deferral or reduction when operational budgets are constrained.

Several MAT-coded preventive maintenance programs show declining work volumes over the review period. As shown in Table 37, the number of gas mains maintained (MAT FHA) declined from 686 in 2019 to 165 in 2024, while actual spending remained relatively flat across the same period, ranging from approximately \$1.1 million at its low to \$1.8 million annually. PG&E reported a unit cost increase due to labor and contract costs such as paving, traffic control, and environmental contracts which resulted in the observed increase in cost per unit, rising from \$2,553 per main in 2019 to \$7,150 in 2024.

Table 37: Preventive Maintenance (costs shown in Thousands unless otherwise stated)

	2019	2020	2021	2022	2023	2024
<i>Adopted Costs</i>	\$701	\$1,201	\$1,235	\$1,243	\$2,855	\$2,912
<i>Actual Costs</i>	\$1,752	\$1,516	\$1,153	\$1,262	\$1,067	\$1,180
<i># Mains Maintained (MAT FHA⁷⁴)</i>	686	368	414	278	192	165
<i>Cost/Unit (\$/repair)</i>	\$2,553	\$4,119	\$2,785	\$4,540	\$5,557	\$7,150

Atmospheric Corrosion Inspection and Repair Programs

Atmospheric corrosion monitoring and repair programs address a known deterioration mechanism affecting above-ground metallic gas infrastructure, including exposed piping, fittings, and station components subject to weathering and coating degradation. These programs encompass four MAT-coded activity types: corrosion inspections (FHK), atmospheric corrosion repairs on gas distribution mains (FHL), atmospheric corrosion repairs on gas service risers (FHM), and atmospheric corrosion repairs at regulator stations (FHN). Because inspection activities generate repair work orders that must subsequently be executed,

⁷⁴ MAT FHA – Preventative Maintenance, Gas Mains – Includes: (1) non-leak repairs to distribution gas mains; (2) rewrap, lower, or paint gas distribution mains; (3) replace cover; protect shallow pipe; (4) replace/repair pipe hangars; (5) replace/relocate less than 100 feet of gas distribution main; (6) identify pipe; and (7) install Electrolytic Test Station (ETS) for the purpose of locating the main. Does not include: (1) main leak repairs; (2) any work related to gas transmission; (3) any work caused by work or alteration by a customer or third party; (4) pothole gas facilities for potential conflicts with third-party work; (5) third-party damage; (6) AC; (7) install ETS for purposes of corrosion prevention; (8) fire valve repair or replacement; (9) main or service alterations due to “sewer cross-bores”; and (10) any corrective work related to sunk trenches or sunk bell holes. This program relates to safety and/or reliability and/or maintenance as it includes: (1) non-leak repairs to distribution gas mains; (2) rewrapping, lowering, or painting gas distribution mains; (3) replacing cover or protecting shallow pipe; (4) replacing/repairing pipe hangars; (5) replacing/relocating greater than 100 feet of gas distribution main; (6) identifying pipe; and (7) installing ETS for the purpose of locating the main. (From PG&E’s RSARs Gas Distribution MAT Descriptions)



a lag between inspection findings and repair completion can develop when repair resources are constrained or work is reprioritized within the broader gas portfolio. However, all remediations must be completed within 39 months of identification, in accordance with federal regulations. Two additional MAT codes, atmospheric corrosion inspections on gas transmission facilities (JOZ) and atmospheric corrosion repairs on gas transmission mains (GJB), are also tracked under this program. However, as noted previously, transmission was not reported until the 2023 GRC.

As shown in Table 38, inspection volumes under FHK fluctuated from 340 in 2019 up to 597 in 2023. PG&E noted that the varying costs are largely due to time factors such as access, and changing conditions between inspections which take place once every three years. Repair activity across the three repair MAT codes shows mixed trends. Distribution main repairs under FHL declined from 143 spans remediated in both 2022 and 2023 to 73 in 2024, while cost per unit ranged from \$12,633 in 2021 to \$21,566 in 2024. PG&E attributes variable costs in the repairs due to the complexity and safety conditions for each location.⁷⁵ Gas service riser repairs under FHM show significant year-to-year variation, peaking at approximately 25,947 repairs in 2021 before declining to 18,607 in 2024, with cost per unit remaining relatively stable across the past 4 years at approximately \$154 to \$296 per unit. PG&E reported the main variation in cost is due to the scope of work to be performed. Regulator station repairs under FHN show a declining trend in unit volumes, from 89 stations mitigated in 2019 to 30 in 2024, while cost per unit increased from \$12,073 in 2019 to \$41,537 in 2024.

Table 38: Atmospheric Corrosion Inspections and Repairs (costs shown in Thousands unless otherwise stated)

MAT		2019	2020	2021	2022	2023	2024
FHK ⁷⁶	Adopted Costs	\$0	\$1,035	\$1,064	\$1,071	\$145	\$149
FHL ⁷⁷	Adopted Costs	\$1,847	\$245	\$252	\$254	\$3,243	\$3,330
FHM ⁷⁸	Adopted Costs	\$0	\$401	\$412	\$415	\$12,499	\$12,832
FHN ⁷⁹	Adopted Costs	\$0	\$578	\$594	\$598	\$1,051	\$1,079
FHK	Actual Costs	\$220	\$500	\$146	\$102	\$201	\$108

⁷⁵ An example of project differences includes the removal and application of coating on a ten-foot section for a 2” pipe versus a thirty-foot section of a 6” pipe.

⁷⁶ MAT FHK – AC Monitoring – Inspect exposed gas mains and services, for AC. This program relates to safety and/or reliability and/or maintenance as it involves inspecting exposed gas mains and services for AC. (From PG&E’s RSARs Gas Distribution MAT Descriptions)

⁷⁷ MAT FHL – AC Main Repairs – Perform expense repair of AC on mains. This program relates to safety and/or reliability and/or maintenance as it involves performing expense repairs of AC on mains. (From PG&E’s RSARs Gas Distribution MAT Descriptions)

⁷⁸ MAT FHM – AC Service Repairs – Expense repairs of AC on services to below the shut-off valve. Does not include: AC repairs of customer gas regulators, HPRs, and meter sets. This program relates to safety and/or reliability and/or maintenance as it involves expense repairs of AC on services to below the shut-off valve. (From PG&E’s RSARs Gas Distribution MAT Descriptions)

⁷⁹ MAT FHN – AC Distribution Regulator Station Repair – Expense repairs of AC on distribution district regulator stations. This program relates to safety and/or reliability and/or maintenance as it involves expense repairs of AC on distribution district regulator stations. (From PG&E’s RSARs Gas Distribution MAT Descriptions)



<i>FHL</i>	<i>Actual Costs</i>	\$981	\$544	\$1,023	\$2,407	\$2,414	\$1,574
<i>FHM</i>	<i>Actual Costs</i>	\$665	\$1,169	\$3,997	\$3,240	\$3,701	\$5,509
<i>FHN</i>	<i>Actual Costs</i>	\$1,075	\$788	\$1,077	\$1,438	\$1,747	\$1,246
<i>FHK</i>	<i># of inspections completed</i>	340	346	520	454	597	454
<i>FHL</i>	<i># of distribution spans remediated</i>	62	28	81	143	143	73
<i>FHM</i>	<i># of gas service risers repaired or re-coated</i>	999	1,845	25,947	17,763	13,229	18,607
<i>FHN</i>	<i># of regulator stations mitigated</i>	89	43	45	55	51	30
<i>FHK</i>	<i>Cost/Unit (\$/inspection)</i>	\$648	\$1,444	\$281	\$225	\$336	\$238
<i>FHL</i>	<i>Cost/Unit (\$/remediation)</i>	\$15,815	\$19,432	\$12,633	\$16,829	\$16,879	\$21,566
<i>FHM</i>	<i>Cost/Unit (\$/repair)</i>	\$666	\$633	\$154	\$182	\$280	\$296
<i>FHN</i>	<i>Cost/Unit (\$/mitigation)</i>	\$12,073	\$18,314	\$23,933	\$26,142	\$34,247	\$41,537

Meter Protection Program

The meter protection program addresses the installation of protective equipment at gas meter sets to reduce the risk of damage from vehicle impact. PG&E’s meter protection installations are tracked as a compliance-driven program with a large system-wide population of potential installations. As of the end of 2023, PG&E classified this program as expense work, funded with MAT EXB. Beginning in 2024, PG&E classified bollard installations as capital work, funded with MAT 27A. In 2024, PG&E completed 2,817 units at a unit cost of \$1,162.

As shown in Table 39, RSAR data indicates a reduction in meter protection program installations (MAT EXB) beginning in 2022, declining from approximately 16,400 completions in 2020 to zero reported completions in 2024. Actual spending followed a similar trajectory, declining from approximately \$11.5 million in 2020 to \$77,000 in 2024, against adopted levels of approximately \$12.7 million in 2023 and \$13.1 million in 2024. Although EXB units were zero in 2024, meter protection units under MAT 27A in 2024 were 2,817 and increased to 30,626 in 2025. During interviews, PG&E described this program as a compliance-driven initiative with a large installation population but relatively modest per-unit risk reduction benefit and noted that work has been subject to risk-based prioritization given limited funding availability.



Table 39: Meter Protection Program (costs shown in Thousands unless otherwise stated)

	2019	2020	2021	2022	2023	2024
<i>Adopted Costs</i>	\$839	\$8,198	\$8,428	\$8,489	\$12,709	\$13,133
<i>Actual Costs</i>	\$8,451	\$11,471	\$7,556	\$1,721	\$1,005	\$77
<i># of Locations (MAT EXB⁸⁰)</i>	10,425	16,429	9,192	1,709	1,255	0
<i>Cost/Unit (\$/Location)</i>	\$811	\$698	\$822	\$1,007	\$801	N/A

Gas System Reliability and Unplanned Downtime Risk

PG&E’s gas transmission system supports a diverse customer base including approximately 286 non-core large-volume customers, which collectively consumed approximately 320.4 billion cubic feet (BCF) of natural gas in calendar year 2024. The transmission system also supplies gas-fired electric generation facilities within the CAISO PG&E planning area, which includes approximately 13,258 megawatts (MW) of installed gas-fired generation capacity. These facilities received approximately 224.4 BCF from PG&E in 2024. PG&E’s system has an estimated annual delivery capability of approximately 1,100 BCF.

The natural gas and electric systems are operationally interdependent. Gas-fired generation provides dispatchable capacity that supports grid stability, particularly when renewable output is limited or electric demand rises rapidly. Unplanned outages or capacity reductions affecting the transmission system from equipment failure, control system malfunction, or deferred maintenance can reduce available generation capacity during periods of peak electric demand, potentially requiring emergency grid operations. This interdependency is relevant when evaluating the condition and maintenance trajectory of aging transmission assets, including those along the Baja Path corridor.

During the current ISM reporting period, the ISM reviewed PG&E's gas transmission risk framework and observed that gas asset unplanned downtime and customer interrupted minutes are not currently incorporated as inputs into its gas risk modeling process, though counts of gas customer outages are reflected on the consequence side of its loss-of-containment risk models. The ISM also noted underspending against adopted GT&S levels, aging compressor infrastructure, and declining work volumes in certain maintenance categories.

DAMAGE PREVENTION (THIRD PARTY DAMAGE)

As part of the ISM’s ongoing review of the Damage Prevention Program, the ISM interviewed PG&E Damage Prevention teams and analyzed PHMSA data on dig-in damages and locate tickets from 2010 to 2024. PG&E's Damage Prevention framework is comprised of operational controls, public outreach, and risk-informed decision-making, and integrates with PG&E's

⁸⁰ MAT EXB – MPP Protection – Includes installing barrier posts in order to protect above ground gas facilities (meters and risers) from damage by vehicles. Does not include: relocation requiring re-running the service from the main, which is under MWC 27. This program relates to safety and/or reliability as it involves installing barrier posts in order to protect above ground gas facilities (meters and risers) from damage by vehicles. (From PG&E’s RSARs Gas Distribution MAT Descriptions)



Transmission Integrity Management Plan (TIMP) and Distribution Integrity Management Plan (DIMP). PG&E's Damage Prevention framework consists of these core elements: public awareness (impressions⁸¹), 811 One Call participation, Locate and Mark response, Standby Governance team, contract engagement and enforcement, and risk modeling and prioritization.

PG&E management reported that current focus areas of excavation damage risk are no-notification (no 811 call), repeat-offender contractors,⁸² data quality and mapping gaps including unlocatable facilities.⁸³ As mentioned in ISM Report 7, data provided by PG&E shows that excavation damage remains one of the gas utility's highest-consequence, time-independent threats.

PHMSA Data Trends

From 2010 to 2024, the ISM observed that PG&E had a downward trend in distribution dig-in damages. Due to the small sample size, no clear trend was apparent for transmission damages over the same period. PG&E attributes the long-term decline in distribution damages with the multi-year program investments in risk-informed locate strategies, contractor enforcement, and training improvements described below.

⁸¹ 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, webpage banner, a mailed notice, or other campaign content.

⁸² When a dig-in incident involves a repeat-offender contractor, DiRT conducts an incident-level factual investigation, identifies root causes, and feeds findings back into contractor outreach, enforcement, and corrective actions.

⁸³ PG&E described addressing unlocatable facilities through field controls, including communication of risk to excavators, application of advanced locating tools and techniques where standard methods are insufficient, and defined escalation paths. As a last resort, when uncertainty cannot be resolved through standard or advanced locating practices, PG&E procedures require coordination with PG&E construction crews to physically expose and verify the facility location before third-party excavation proceeds.

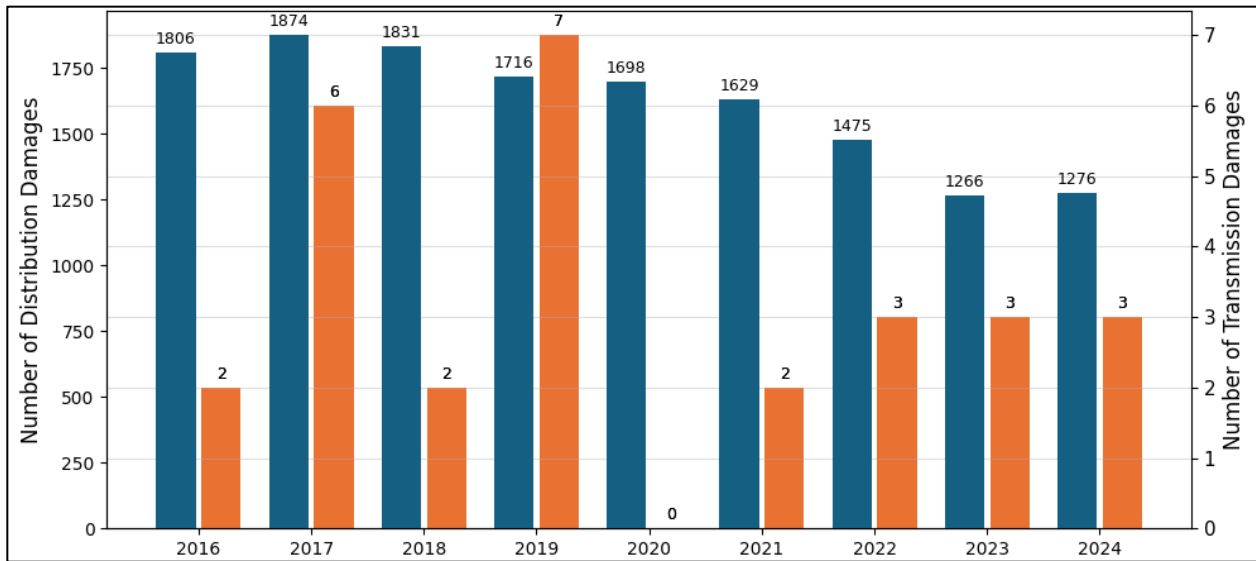


Figure 34: Excavation Damages by Year (2016-2024) (Distribution in blue, Transmission in orange)

From 2015 to 2024, PG&E reduced distribution damages across all cause categories.

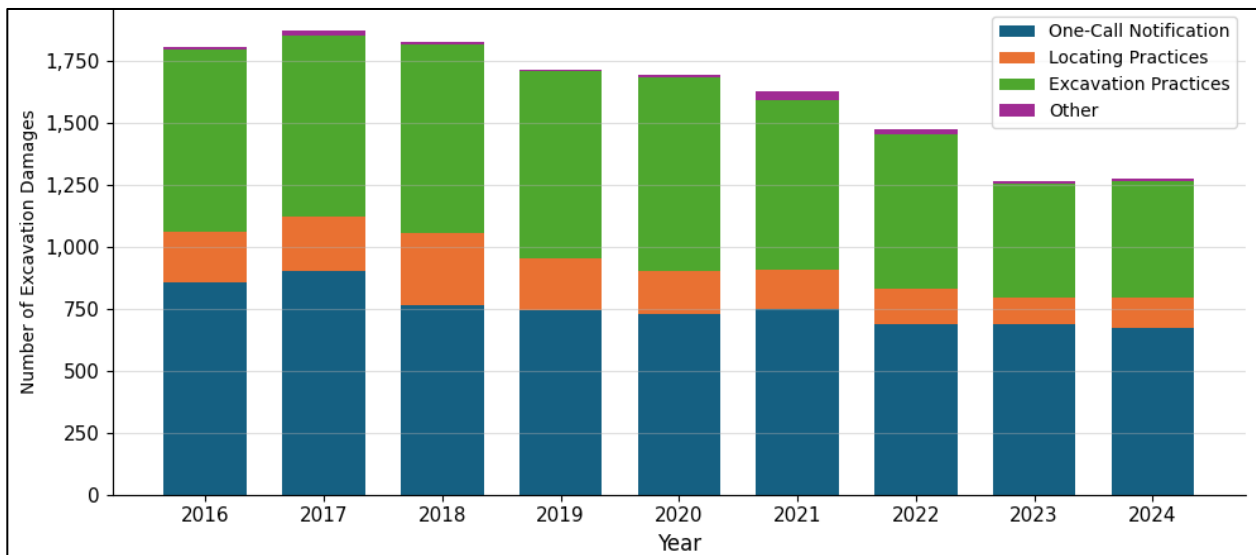


Figure 35: Distribution Excavation Damages by Cause (2016-2024)⁸⁴

⁸⁴ PHMSA categorizes excavation damage causes into the following areas: 1. One-Call Notification Practices Not Sufficient: Failure to notify the local One-Call center (e.g., 811) prior to excavation, failure to wait the required time for operators to locate and mark lines or excavating after the locate ticket has expired. 2. Locating Practices Not Sufficient: facility operator provides wrong information about the location or depth of the pipe, pipe marked incorrectly or not at all by the operator, or locating technician fails to mark the entire area covered by the ticket. 3. Excavation Practices Not Sufficient: Failure by excavator to use care (not using hand tools or "soft digging" techniques to confirm the exact location of the pipe after spotting it), digging into or through marked lines, or failing to properly support pipes after exposing them. 4. Other Causes: Damage by a party not directly involved in



Locate ticket volumes (distribution only) saw an increase from 2016 to 2021, driven in part by rising construction activity and expanded 811 utilization. However, ticket volumes have decreased in recent years driven by various factors. PG&E reported that a contributor to the spike in ticket volumes observed from 2019 to 2022 was second-party pole testing activity, which accounted for a disproportionate share of tickets submitted to the USA North 811 notification center during that period. Figure 36 show the distribution of excavation ticket volumes by party from 2020 to 2025, based on data provided by PG&E.

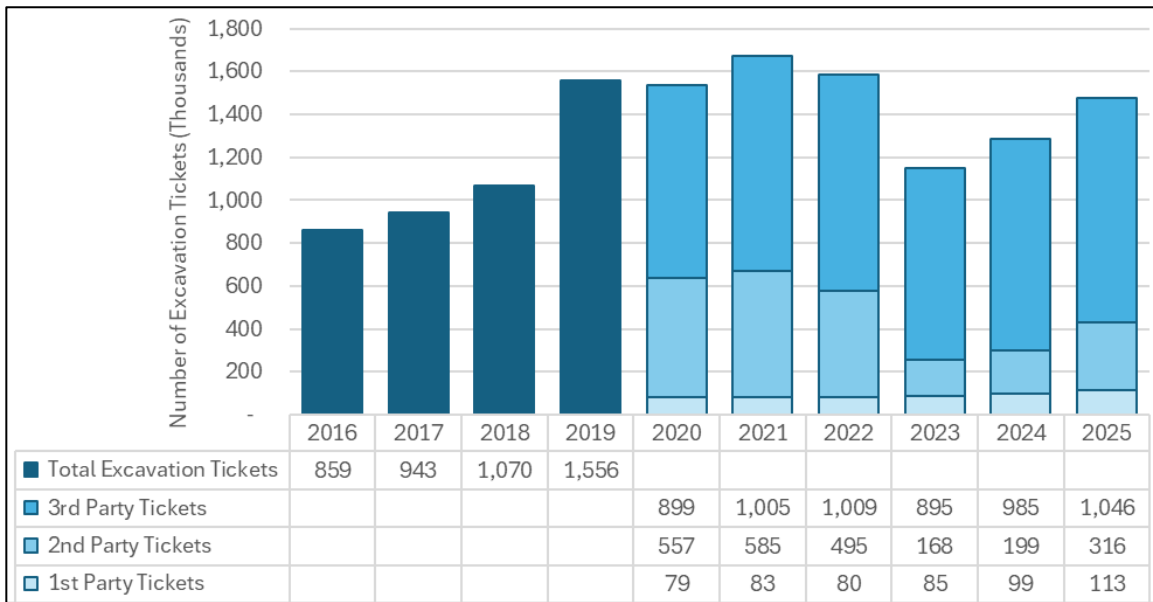


Figure 36: Distribution Excavation Tickets by Year (2016-2024)⁸⁵

The ratio of damages per 1,000 locate tickets declined from 2016 to 2019, and show minimal change from 2019 to 2024. PG&E benchmarks this metric against the industry through the American Gas Association (AGA) and has indicated that PG&E ranks within the top 10%–25% industrywide.⁸⁶

the construction activity, such as traffic accidents or extreme natural occurrences, damage resulting from incorrect official maps of the area, or instances where facilities exist but were never registered with the One-Call system.

⁸⁵ These figures may not match PHMSA-reported totals. PG&E reports that minor differences are attributable to timing misalignments between PG&E's Pacific Standard Time systems and the 811 system's Greenwich Mean Time timestamps, as well as instances where remarks or returns associated with the same ticket ID are captured separately in reporting extracts.

⁸⁶ AGA benchmarking participation is voluntary and subject to a confidentiality agreement between AGA and its members. Year-over-year variation in the total number of participating utilities reflects changes in voluntary participation rather than methodology changes. PG&E ranked as follows among AGA participating utilities: 2019: 18th of 96 (top 19%); 2020: 8th of 85 (top 9%); 2021: 12th of 83 (top 14%); 2022: 8th of 88 (top 9%); 2023: 9th of 78 (top 12%); 2024: 11th of 82 (top 13%).

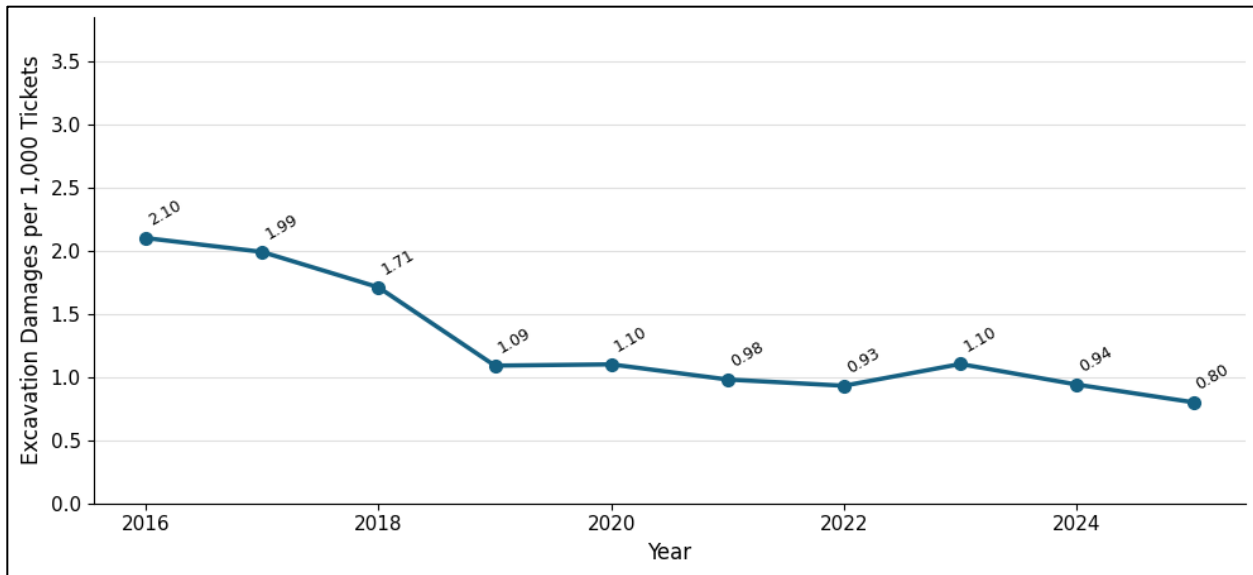


Figure 37: Distribution Excavation Damages per 1,000 Locate Tickets (2016-2024)

The proportion of distribution damages attributable to locate errors declined from 2018 to 2024, as shown in Figure 38; note that the figure displays the 2018–2024 period only, as pre-2018 data reflects differences in organizational structure and investigation practices limiting a direct comparison. These proportions largely reflect 3rd party damages per 1,000 locate tickets, with 1st party damages per 1,000 locate tickets remaining below 0.048 and 2nd party damages per 1,000 locate tickets remaining below 0.078. In January 2018, PG&E named a Director of Field Services and Locate & Mark. In 2019, PG&E formally established the Damage Prevention organization, introducing greater consistency and independence in damage investigation and cause classification. Prior to these changes, PG&E did not categorize comparative fault events between excavators and PG&E solely as locate errors, and PG&E did not conduct damage investigations uniformly for all damages. Dig-in Reduction Team’s (DiRT's) damage investigations scope expanded incrementally following its formal launch in April 2015.⁸⁷

The post-2018 trend is reported to be a result of PG&E's investment in National Utility Locating Contractors Association (NULCA) accreditation Locate & Mark training (implemented as the standard for internal locator qualification beginning February 2017) and introduction of Field Training Outline (FTO) in 2021-2022, which included specific elements to target gas main continuity issues at steel to plastic transitions. These trainings addressed location challenges

⁸⁷ DiRT was formally launched on April 1, 2015. Investigation coverage: initial scope covered third-party contractor damages on gas facilities only, then expanded to third- and second-party contractors and homeowners on gas facilities, then added electric dig-in investigations, and ultimately expanded to full coverage across all parties and commodities. As a result, pre-2016 data does not reflect comprehensive, consistent investigations across all damage events.



at plastic-to-steel transitions and contributed to the reduction in locate errors observed in later years.⁸⁸

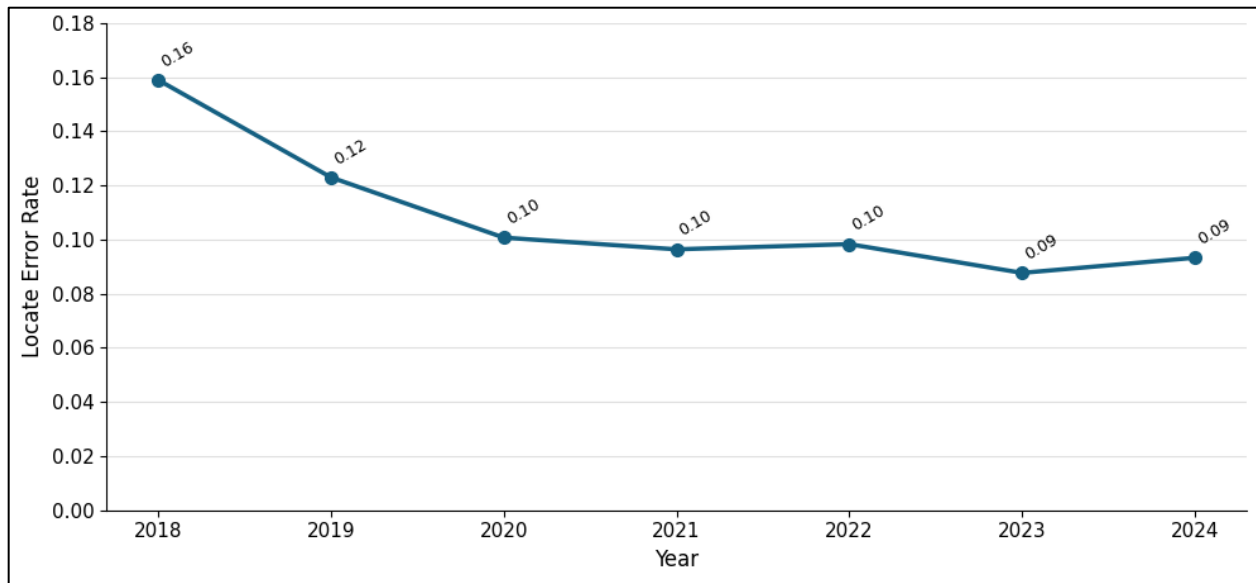


Figure 38: Distribution Proportion of Damages with Locate Issues (2018-2024)

PG&E’s Assessment of Damage Prevention Initiatives

As part of the ISM's damage prevention review, the ISM asked PG&E management to identify the initiatives it considered most effective in reducing excavation damages over the past decade. The following reflects PG&E's self-reported assessment of those programs, which the ISM considered alongside independent field observations and dig-in data trends.

PG&E management identified Standby Governance ("Watch-and-Protect") as one of its most effective damage prevention strategies over the past decade. Standby Governance is a service provided to excavators by PG&E in which Standby inspectors serve as an objective representative of the utility on site to observe and protect PG&E facilities. Standby Governance evolved substantially during this period, beginning as a non-risk-based strategy that PG&E states was less effective due to over-deployment in support of low-risk excavations. PG&E subsequently shifted to a risk-informed Standby Governance strategy, using excavator history, risk model outputs, and asset criticality to target high-risk excavations. Following this shift, PG&E reported a reduction in damage rates to high-priority facilities and a reduced backlog in scheduling.

In addition to this shift to risk-informed Standby Governance, PG&E stated that its DiRT

⁸⁸ PG&E implemented NULCA-accredited Locate & Mark training as the standard for internal locator qualification in February, 2017. In 2020–2021, PG&E analysis identified Gas Main Continuity, which is the loss of electrical continuity at plastic-to-steel transitions, as a recurring factor contributing to locate challenges. In October 2021, PG&E initiated a formal Corrective Action Plan addressing this risk, and in 2021–2022 developed an enhanced training through the Field Training Outline and a dedicated Gas Academy module. Refreshed training materials were deployed in 2023–2025.



investigations and root cause follow-up process, and its Targeted Contractor Enforcement and Cost Recovery strategy, have been effective in reducing dig-in damages caused by repeat-offenders. DiRT was formally launched on April 1, 2015, and investigation coverage expanded incrementally. DiRT initially covering third-party contractor damages on gas facilities only, and subsequently expanding to second-party contractors, homeowners, and electric facilities. DiRT investigations and root cause follow-ups supported the Targeted Contractor Enforcement and Cost Recovery team's repeat-offender identification and targeted interventions.

The Targeted Contractor Enforcement and Cost Recovery program reduced repeat-offender damages by expanding damage recovery claims and pursuing lower-value recovery actions, which increased contractor attention to compliance. PG&E reported that the number of repeat-offender contractors⁸⁹ declined from 121 in 2019 to 63 in 2023, a reduction of approximately 48%. PG&E noted that the most significant reduction occurred between 2022 and 2023 and reflects the sustained application of long-standing damage prevention strategies, including customer education, targeted outreach, Damage Prevention workshops, and DiRT. The number of repeat-offender contractors increased slightly from 63 in 2023 to 78 in 2024, though activity levels remained lower than those observed prior to 2023.

PG&E reported that the integration of the Damage Prevention program with Integrity Management (TIMP/DIMP) has also been an effective strategic development, with risk models being used to inform patrol frequency, mitigation planning, and CAP development. Overall, PG&E improved its damage prevention performance by shifting to a more risk-informed approach, focused on reducing repeat-offender and high-risk excavator damages.

PG&E also identified effectiveness through internal process improvements. PG&E stated that NULCA Accreditation training and continued training development improved the accuracy of field locate markings, reducing locate-error dig-ins. PG&E observed improved effectiveness through the Digital Ticket Management System (TMS/"Locate App") initiative, reflected in a reduction in late workable tickets and a reduction in damages attributed to procedure non-compliance.

PG&E management identified broad and untargeted public awareness campaigns, voluntary 811 workshops, and non-risk-based Standby Governance as the least effective damage prevention strategies over the same time period. PG&E indicated that these strategies limited effectiveness because they tend to reach primarily low-risk parties and fail to influence high-risk excavators. Through the 811/ "Call Before You Dig" Public Awareness & Outreach initiative, PG&E observed large year-over-year increases in workshop attendance. However, PG&E indicated that the voluntary workshops produce lower effectiveness at reducing excavation damage risk because high-risk excavators and repeat offenders do not tend to attend. PG&E is reducing reliance on voluntary workshops in favor of programs that demonstrated greater effectiveness

Of the initiatives implemented over the past decade, PG&E is not currently able to observe program specific improvements directly attributable to AI-Based Ticket Duration Modeling,

⁸⁹ In this context, the term "repeat offender" is defined as a licensed contractor with two or more at-fault damages within a single calendar year, based on PG&E's Damage Prevention Dashboard data available from 2019 onward.



Third Party Excavator Certification (Gold Shovel → DPI), GIS & Asset Data Enhancements, or Independent Audits (Ticket Timeliness + Field Compliance), as these programs were incorporated to collectively enhance overall program performance rather than as standalone measurable interventions.

Emergency Response

PG&E established procedures for responding to incidents that result in gas releases, including third-party damage events such as excavation-related dig-ins. These procedures focus on rapid mitigation of hazards, public safety, and gaining control of the situation. Once notified of such an event, PG&E field personnel are deployed and directed to secure the site, assess event conditions, and coordinate with emergency responders as needed. Initial actions taken include restricting access to the site, eliminating potential ignition sources, and evaluating the extent of the gas release.

If hazardous gas concentrations are detected, PG&E reported that its personnel immediately initiate evacuation protocols and establish controlled safety zones. Field personnel use gas detection equipment to determine the presence and concentration of gas and continue to perform surveys of the surrounding area. A perimeter will be established and maintained based on the gas measurements, and access will be restricted to the area and structures. PG&E coordinates with emergency responders to remove people from affected areas and prevent re-entry. Conditions in the area are to be continuously monitored, and the safety zone adjusted as needed if measurements indicate changes in gas levels and/or potential migration of gas. PG&E stated that additional assessments of adjacent infrastructure (subsurface pathways, structures, and utility corridors) will be performed to evaluate gas migration risks and confirm that conditions have been made safe prior to restoration activities.

Concurrently, PG&E reported that personnel will take action to isolate and control the release and stop any leaks, which include field activities such as closing valves, or restricting flow (squeezing) in a pipeline where required. PG&E personnel investigate and grade the leak to determine the severity of the event, with hazardous leaks requiring immediate mitigation and repair. Additionally, DiRT (mentioned above) performs post-incident investigations to identify root causes and determine and employ appropriate corrective actions.

PG&E tracks key performance indicators associated with emergency response, including time to arrive on-site, and time to isolate and shut-in the gas supply following hazardous leaks or unintended gas releases typically caused by dig-ins. This is reported to the CPUC in PG&E's Safety and Operational Metrics Report (SOM), with the latest semi-annual update being posted on September 30, 2025.⁹⁰ PG&E reported the following emergency response times in its September 2025 SOM,⁹¹ which covers the time period from January through June 2025 and represents the most recent publicly available data:

- *Time to Respond to Emergency Notification:* Average response time of 19.8 minutes, and

⁹⁰ PG&E's (U39M) Safety and Operational Metrics Report, September 30, 2025 Chapter 4 for the period from Jan

⁹¹ Available at <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2025-mid-year-som-report---september-2025.pdf>



a median response time of 18.3 minutes compared against 2025 targets of 21.3 minutes for average and 19.6 minutes for median response times.

- *Gas Shut-In Time, Mains*: Median shut-in time 71.5 minutes compared against a 2025 target of 87.4 minutes.
- *Gas Shut-In Time, Services*: Median shut-in time 31.3 minutes compared against a 2025 target of 39.8 minutes.
- *Time to Resolve Hazardous Conditions for Grade 1 Leaks*: Median resolution time 124.5 minutes compared against a 2025 target of 173.9 minutes.

PHMSA requires operators to reply promptly to emergency notifications, and take immediate action to protect life and property. While a direct comparison to industry average response times is not readily accessible in the public domain, PG&E, SoCalGas, and SDG&E are all required to submit annual Safety Performance Metrics Reports⁹² to the CPUC. These reports also include emergency response time metrics, however, the SPMRs were only available through 2023.

KETTLEMAN CORRECTIVE ACTION STATUS

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). During the current ISM reporting period, the ISM reviewed documentation provided by PG&E, including responses to ISM data requests, and held interviews with PG&E personnel responsible for implementation of the corrective actions. The ISM also reviewed updates regarding revised procedures, training development, and other process changes associated with the corrective actions. The following summarizes the status of each corrective action and notable changes to policies, procedures, and operational practices reported by PG&E.

- **RCCAPR1 – Develop Safety and Culture Achievement Plan (In Progress)**
PG&E reported that work continues on the development of a Safety and Culture Achievement Plan. The plan is intended to strengthen safety culture and leadership development within Gas Operations. PG&E indicated that this effort includes analysis of SIF data trends and development of leadership training and human-performance initiatives. PG&E reported that human-performance tools are being integrated into daily operations, including daily operating reviews and safety summits. Despite the five-year timeline for this corrective action, PG&E forecasts accelerating plan completion.
- **RCCAPR2 – Establish Exclusion Zones (Complete)**
PG&E reported that exclusion-zone requirements for blowdown and purging activities were formalized through issuance of its utility procedure: Blowdown and Purging Operations for Gas Pipelines.⁹³ The procedure establishes exclusion-zone guidance

⁹² 2023 SoCalGas SPMR dated March 2024, 2023 SDGE SPMR dated March 2024 downloadable at <https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/wildfire-and-safety-performance/safety-performance-metrics-reports>

⁹³ Blowdown and Purging Operations for Gas Pipelines (TD-4800P-03)



based on pipeline pressure, pipe type, and blowdown configuration. PG&E reported that it communicated the procedure through live training sessions with field and engineering personnel.

- **RCCAPR3 – Install and Stage Vent Stacks (In Progress)**

PG&E reported that gas engineering developed a standardized vent stack design intended to support blowdown operations during gas purging activities. Prototype units are being fabricated and tested, with a current prototype being prepared for field testing and evaluation during a future gas clearance operation.

- **RCCAPR4 – Implement Risk Identification and Readiness Reviews (Complete)**

PG&E reported that it implemented recurring Risk Identification and Readiness Reviews to evaluate complex gas clearance operations prior to execution. Clearances are reviewed based on factors such as operational complexity and system conditions. PG&E also reported that it is using SAP to flag clearance projects based on complexity to enhance visibility, tracking, and reporting.

- **CC1CA1 – Develop Configuration Control Devices (Complete)**

PG&E reported that it evaluated potential Enhanced Configuration Control Devices (ECCDs) through internal programs as well as benchmarking with peer utilities. Based on this evaluation, PG&E determined that ECCDs would not provide measurable safety benefits due to the different pipeline configurations encountered during gas clearance operations. PG&E reported that existing lockout/tagout (LOTO) practices will remain in place and that it has planned an external review of lockout procedures and field implementation practices.

- **CC1CA2 – Evaluate Clearance Supervisor Roles and Responsibilities (Complete)**

PG&E reported that it conducted a review of regulatory requirements, gas standards, and operational responsibilities associated with clearance execution, and developed a Work Jurisdictional Matrix to clarify responsibilities of the parties responsible for gas clearances. PG&E reported that it communicated the matrix to operational groups through leadership briefings and team meetings.

- **CC1CA3 – Implement Clearance and Tagging Event Monitoring Process (Complete)**

PG&E reported that it made modifications to SAP to identify and flag all clearance-related events. PG&E indicated that the Gas Clearance Committee reviews these events to identify trends, potential procedural improvements, and opportunities for corrective action.

- **CC2CA1 – Implement Training for Clearance Operations (In Progress)**

PG&E reported that it developed training curricula for Clearance Supervisor II roles. The course is intended to provide a higher level of training for personnel to supervise high complex clearances. PG&E indicated that it expects to complete development and implementation of the training program by December 2026, with training activities continuing thereafter as part of ongoing Clearance Supervisor training requirements.

- **CC2CA2 – Develop A-38 Job Aid and Purging Training (Completed)**

PG&E reported that it revised the original job aid concept to develop a new Utility Procedure (TD-4800P-03), "Blowdown and Purging Operations". The procedure document establishes standardized guidance for blowdown, purge out of service,



purge into service, and restore natural gas systems.

- **CC3CA1 – Implement Trending and Performance Monitoring (Complete)**

PG&E reported that it implemented a monitoring program to collect and review operational data from gas clearance activities. PG&E indicated that data are collected through field visits conducted by internal teams and external quality-assurance personnel and compile the results into dashboards used to support performance monitoring and continuous improvement.

- **CC3CA2 – Establish Quality Improvement for High-Risk Programs (Complete)**

PG&E reported that it implemented a Quality Improvement Plan framework to support continuous improvement within high-risk programs in Gas Operations. The framework includes tracking of key program metrics and integration with broader quality-assurance processes.

PG&E reported that, with the exception of the development of the Safety and Culture Achievement Plan, it completed and implemented the majority of corrective actions associated with the Kettleman RCE through updates to procedures, internal processes, training programs, and operational practices. The ISM will continue to monitor PG&E's progress on the Safety Culture and Achievement Plan and may provide updates on that effort in subsequent reports as appropriate.



APPENDIX: KRI SUMMARY TABLE

Risk Name	KRI Name	KRI Description
Electric Transmission System-Wide Blackout	Transmission System-Wide Restoration Readiness	a) Black-start Resource Availability b) Availability of 2 or more river systems to support Blackstart Resources required for response to a Transmission Systemwide Blackout
Climate Change	Q1 Major Storms and High Precipitation Events	Tracking of the number of Atmospheric River events that occur in PG&E's service territory.
Climate Change	Q2 Hydrology Condition Drought/Flooding – Drought Status	Tracking of the State's hydrology conditions to indicate whether or not the State is in a state of drought or flooding and to compare those metrics to the range indicated based on climate projections.
Climate Change	Q2 Hydrology Condition Drought/Flooding – Reservoir Levels	Tracking of the State's hydrology conditions to indicate whether or not the State is in a state of drought or flooding and to compare those metrics to the range indicated based on climate projections.
Climate Change	Q3 High Temperature (Reported Annually)	Tracking of the Average of Five Regions' Highest Daily Temperature for that Year against the climate projections for a 1-in-2-year and 1-in-10-year maximum daily temperature projection for each PG&E region.
Climate Change	Q4 Sea Level Rise & Coastal Flooding	Tracking of the number of coastal flooding events that occur in PG&E's service territory.
Failure of Electric Distribution Overhead Assets	Distribution Aging Work Following Inspection of Vegetation	Distribution Routine Annual inspection and Second Patrol - Annual Routine and Second Patrol are in scope for this KRI which tracks the tree work completion date from date of inspection, including constrained units. Timeliness of tree work completion
Failure of Electric Distribution Overhead Assets	Just-In-Time Detection Distribution Asset Findings (Inspections)	The KRI measures the percent of just-in-time findings (priority A- and X-tags identified by inspections) over all failures (just-in-time findings + in-service failures). This percentage reflects the effectiveness of the inspection program in catching just-in-time findings, thus preventing the negative consequences of in-service failures.



Risk Name	KRI Name	KRI Description
Failure of Electric Distribution Overhead Assets	Just-In-Time Detection Distribution Asset Findings (Volume)	The KRI measures the total volume of all failures (just-in-time findings and in-service failures) in the preceding 12 months. This provides the trend of overall system health.
Failure of Electric Distribution Substation Assets	Distribution Substation - % Just-In-Time Detection Emergency Replacement	The measure of the asset failure risk containment plan effectiveness by tracking the % Just-In-Time (JIT)/Imminent emergency replacements initiated out of total emergency replacements initiated.
Failure of Electric Distribution Underground Assets	Isolation Zones with Open COE Notification	The KRI measures the number of customers on isolations zones impacted by cable and switch COE notifications. This number reflects the number of isolation zones with equipment that is not functioning as designed or directly downstream from said equipment, thus reducing the redundancy in the system and increasing the risk of larger sustained customer interruptions.
Failure of Electric Distribution Underground Assets	Open COE Notifications	The KRI measures total number of open cable and switch COEs. The number of COE notifications open at any given time is indicative of amount of degradation in the system. A decrease in the number of COE notifications is indicative of the system as a whole operating as intended and therefore a reduction in risk of a larger sustained outage.
Public Contact with (Intact) Energized Electrical Equipment	3rd Party Caused Outages	A third-party caused outage that is due to an interaction with an intact PG&E asset. Outages caused by third party that were car pole related or resulted in a SIF are excluded from this metric.
Public Contact with (Intact) Energized Electrical Equipment	Electric Distribution Dig In Rate	Rolling 12 month average of Electric Distribution Dig-ins per 1,000 ED miles of pipe. Dig-ins are defined in this metric as either reportable or non-reportable.
Failure of Electric Transmission Overhead Assets	Just-In-Time Detection Transmission Asset Findings - JITD Percentage	The KRI measures the percent of just-in-time detection failures (A priority notifications identified by inspections) over all failures (just-in-time failures + in-service failures).



Risk Name	KRI Name	KRI Description
Failure of Electric Transmission Overhead Assets	Just-In-Time Transmission Asset Findings – Total A Tags	The KRI measures the total volume of all failures (just-in-time failures and in-service failures) in the preceding 12 months.
Failure of Electric Transmission Overhead Assets	Transmission Aging work following Inspection of Vegetation	This KRI measures time delays in completing the vegetation work and highlights work status when vegetation work is aged 12 months or greater post inspection date. Transmission Annual Routine (including orchard and substation) and Hazard Patrol programs are in scope.
Failure of Electric Transmission Substation Assets	Transmission Substation - % Just-In-Time Detection Emergency Replacement	The measure of the asset failure risk containment plan effectiveness by tracking the % Just-In-Time (JIT)/Imminent emergency replacements initiated out of total emergency replacements initiated.
Failure of Electric Transmission Underground Assets	Average Outages per Cable Circuit (AOCC)	The average number of times an underground cable circuit in the PG&E electric transmission system is unavailable due to an automatic operation of a protective device such as a circuit breaker.
Wildfire	Weather Normalized CPUC RFI in HFRA	The number of ignitions in R3+ conditions divided by the number of miles in R3+ conditions times 100,000. Rate: $(R3+ \text{ Ignition} / R3+ \text{ Circuit Miles}) * 100,000$
Failure of Electric Distribution Underground Assets	Network Failures	This KRI measures the failures including all equipment and cable in service failures. Excludes failures caused by third party.
Failure of Electric Distribution Underground Assets	Network Transformer Oil Testing Results	This KRI measures the percent of transformers with oil issues ($\#$ of oil filled transformers with oil issues requiring action / Total $\#$ of oil filled transformers on network system).