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PG&E

INDEPENDENT SAFETY MONITOR STATUS UPDATE REPORT

October 4, 2024

EXECUTIVE SUMMARY

This report provides an update on the safety monitoring of Pacific Gas and Electric Company's (PG&E) operations, as conducted by the Independent Safety Monitor (ISM), for the ISM reporting period covering April 1, 2024 through September 30, 2024. The monitoring focused on PG&E's Electric and Gas Operations. Key findings and developments in both electric and gas operations are presented below.

Electric Operations

The focus for electric operations during this reporting period included Ignition and Reliability Trends, Fast Trip Programs, Risk Models, Distribution Infrastructure, Transmission Infrastructure, and Vegetation Management. Data showed an increase in ignitions in High Fire Threat Districts (HFTD) and High Fire Risk Areas (HFRA) in the first eight months of 2024 as a result of more extreme wildfire conditions, with a 31% increase in ignitions compared to the same period in 2023. Vegetation contact, equipment failure, and third-party contact were identified as the primary causes of these ignitions. In response to the more extreme conditions in 2024, PG&E formed a special Ignition Task Force to explore and implement supplemental mitigation measures to stem the increase in heat-related ignitions which occurred earlier in the year.

In the area of risk modeling, PG&E updated its wildfire risk models and integrated new Fire Science 5.0 into its Public Safety Power Shutoff (PSPS) program. This includes more accurate predictive capabilities to guide decision-making during high-risk fire conditions.

This report also notes PG&E's continued efforts in evolving inspection and maintenance processes within its electric distribution infrastructure. This includes enhancements in drone-based aerial inspections and a revised tagging system aimed at prioritizing and addressing identified infrastructure issues. Vegetation management remains a critical component of these efforts, with the ongoing monitoring of areas at high risk of ignitions due to vegetation contact.

Gas Operations

In gas operations, the ISM focused on PG&E’s updates to the Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) risk models, as well as improvements in leak management, construction quality assurance (QA), and the Maximum Allowable Operating Pressure (MAOP) program.

PG&E’s TIMP risk model assesses the likelihood and potential consequences of failures in its transmission pipeline system. PG&E updated its risk assessments and adjusted its approach to managing threats such as external corrosion and third-party damage. Similarly, updates to the DIMP risk model, which focuses on distribution pipelines, adjusted PG&E’s processes for prioritizing maintenance and inspection activities.

PG&E’s Leak Survey and Leak Management Process underwent changes in detection technologies and staff training. PG&E updated its data accuracy and mapping systems to facilitate the identification of high-risk areas. PG&E revised QA processes related to construction activities, with particular attention to close-out procedures and records management.

PG&E continues its efforts in reconfirming MAOP compliance, with ongoing evaluations of pipeline integrity in high-consequence areas. PG&E expanded its In-Line Inspection (ILI) program to support this process by providing detailed assessments of pipeline conditions.

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) has been 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.

Based on PG&E's electric operations and infrastructure changes, the ISM's findings, and discussions with the CPUC, the ISM's electric operations and infrastructure focus continued to evolve from the previous report. The current ISM reporting period is directed toward 1) Ignition and Reliability Trends, 2) Fast Trip Programs, 3) Risk Models, 4) Distribution Infrastructure, 5) Transmission Infrastructure, and 6) Vegetation Management. These focus areas are likely to continue evolving.

Based on PG&E's gas operations and infrastructure changes, the ISM's findings, and discussions with the CPUC, the ISM's gas operations and infrastructure focus also evolved and during this reporting period was directed toward 1) Risk Model Updates, 2) Construction QA/Quality Control (QC), 3) Leak Survey and Leak Management, 4) Construction Close-Out and Records Management, 6) Damage Prevention, 7) Safety Management, 8) Maximum Allowable Operating Pressure Program, 9) In-Line Inspection Program, and 10) Gas Asset Data Management. These focus areas are also likely to continue evolving.

The ISM's first four reports, hereafter referred to as "ISM Report 1", "ISM Report 2", "ISM Report 3", and "ISM Report 4" (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), and October 1, 2023, through March 31, 2024 (published April 4, 2024) 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 5", covers the reporting period April 1, 2024, through September 30, 2024. It was developed based on the stipulations of the ISM Contract and the reporting directive included within CPUC Resolution M-4855. This ISM Report 5 is designed to summarize the oversight activities performed by the ISM during the reporting period described and the related observations.

This ISM Report 5 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 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 5 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 5. 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.

GENERAL OBSERVATIONS

CORE LEADERSHIP CHANGES

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

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

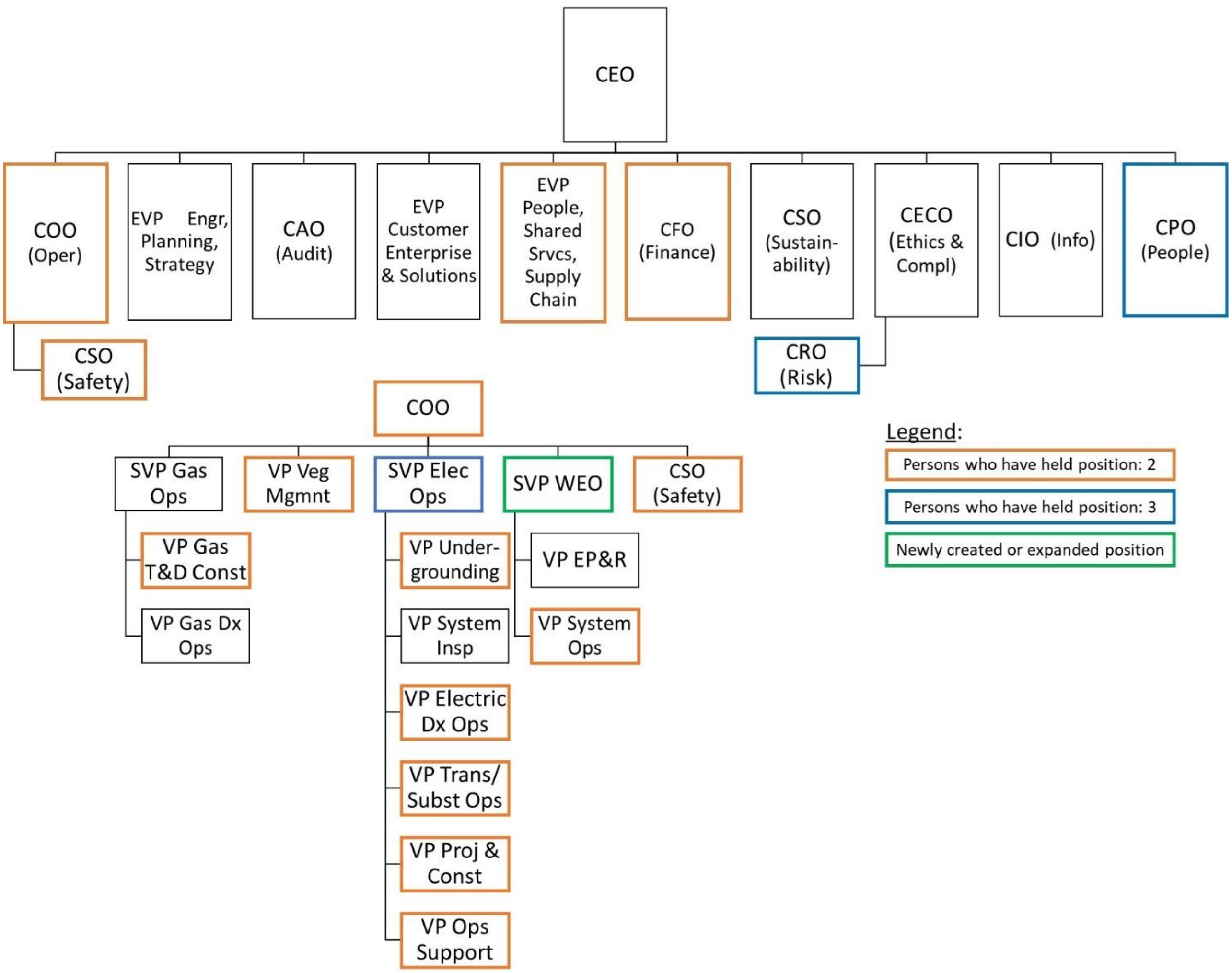

Figure 1: PG&E Senior Leadership Changes Since January 2022

As depicted in the top portion of Figure 1, 30% of the positions reporting to the Chief Executive Officer ("CEO") had two incumbents, and 10% had three incumbents. As depicted in the bottom left portion of Figure 1, 20% of the positions reporting to the Chief Operations Officer had three incumbents, 40% of the positions reporting had two incumbents, 20% were newly created positions, and 20% were expanded.

During each of the respective ISM reporting periods, the ISM interviewed employees, attended meetings, and reviewed data provided by PG&E. Through these monitoring activities, the ISM observed that the frequent leadership changes caused some operational disruption, including a several-month slow-down and re-ramp as the new leaders of work groups determine their strategy and the related actions to achieve that strategy.

During the current ISM reporting period, the ISM observed the following senior leadership changes in areas directly linked to the ISM's purview:

- March 2024, Jamie Martin resigned as Vice President of the Undergrounding Program, and was replaced by Matt Pender (Senior Director, Undergrounding) on an interim basis.
- April 2024, Peter Kenny was selected to lead Electric Operations, which had been led on an interim basis by Sumeet Singh. Peter previously served as the Senior Vice President of Major Infrastructure Delivery (MID).
- April 2024, the programs housed under MID were reassigned as follows:
    - The Undergrounding Program and System Inspections report to Electric Operations.
    - Vegetation Management reports to the Chief Operations Officer.
- Electric Systems Operations, formerly under Electric Operations, reports to Wildfire and Emergency Operations (WEO).
- June 2024, Austin Hastings was selected for the role of Vice President, Gas Engineering, which had been led on an interim basis by Raymond Thierry. Austin previously served as Senior Director Gas Strategy Execution and System Planning.

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

ELECTRIC OPERATIONS OBSERVATIONS

The ISM monitors certain safety and risk aspects of PG&E's electric operations and infrastructure. As outlined in the scope of the ISM Contract and in consultation with the CPUC, the ISM's electric operations and infrastructure focus in this ISM Report 5 is directed toward: 1) Ignition and Reliability Trends, 2) Fast Trip Programs, 3) Risk Models, 4) Distribution Infrastructure, 5) Transmission Infrastructure, and 6) Vegetation Management.

IGNITION AND RELIABILITY TRENDS

Ignitions

In ISM Previous Reports, the ISM presented information on the detailed sources of data received to track ignition totals and suspected root causes, and information on the general downward trend in ignitions linked to PG&E equipment in High Fire Threat Districts (HFTD) and High Fire Risk Areas (HFRA) over the 2017 to 2023 period. During this seven-year period, total CPUC reportable PG&E facility ignitions in these HFTD/HFRA areas (where most of the catastrophic fires occurred) declined from 201 to 65 (a 68% reduction).

As detailed below, PG&E sees the increase in CPUC reportable PG&E facility ignitions above the lower levels experienced during 2023 as a result of more extreme wildfire conditions in 2024. Figure 2 shows that the number of CPUC reportable PG&E facility ignitions in HFTD/HFRA through September 10, 2024 of 71, currently exceeds the 2023 total of 65, but remains below the prior 3-year average for the same year-to-date period.

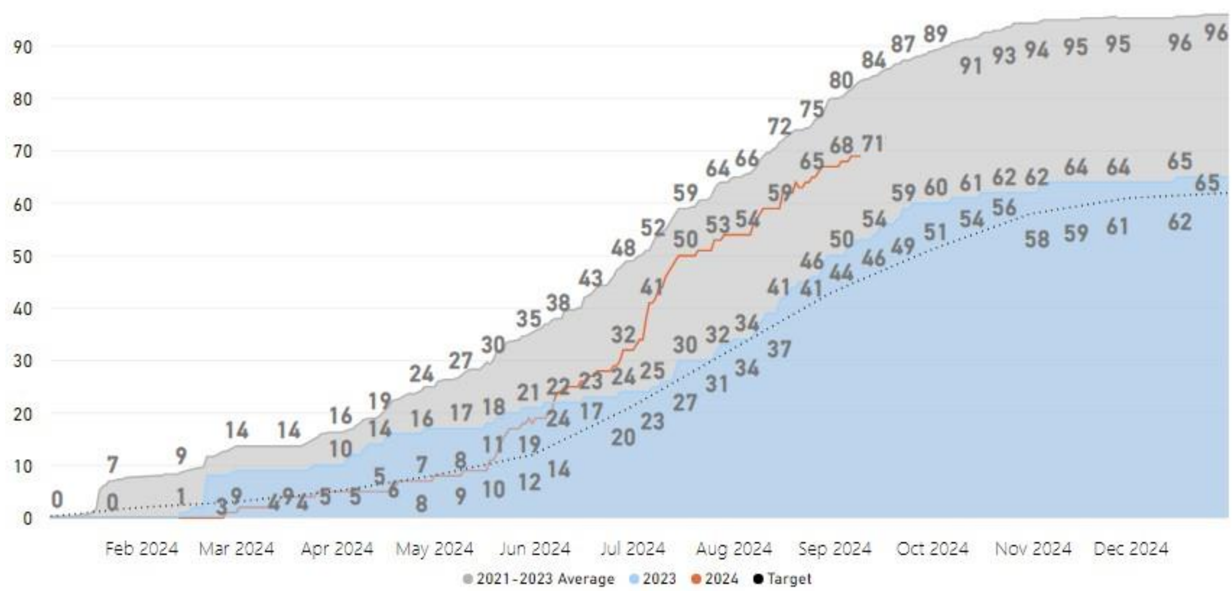

Figure 2: Cumulative CPUC Reportable PG&E Facility Ignitions in HFTD + HFRA

The leading causes of these 71 ignitions were vegetation contact (41%), equipment failure (35%), and 3rd party contact (21%). PG&E noted that the majority of the fires associated with these ignitions were between 1 meter and a quarter acre in size, with only one fire greater than 5,000 acres (under investigation), which principally burned grass, and did not impact any structures or population.

PG&E also tracks the number of ignitions which occur when the Fire Potential Index is R3 or higher (a level which PG&E notes accounts for 95% of the acres burned in its historical dataset, and 100% of the fatalities and structures destroyed). Through September 10, 2024, there were 38 reportable fire ignitions during R3+ conditions in HFTD/HFRA versus 21 during the same period in 2023.

One of the reasons for the larger percentage increase in R3+ ignitions is more extreme environmental conditions during the first 8 months of 2024, resulting in a 25% increase in the cumulative number of PG&E circuit mile days during R3+ conditions. These worsened conditions are also reflected in the number of wildland fires and total acres burned across the State, which are higher year-to-date in 2024, than the comparable periods in 2023 and the average over the prior 5-years. PG&E further stated that extensive grass crop and vegetation growth arising from the widespread rainfall in the winter of 2023, followed by the intense heat of June and July, created ample dry fuel capable of turning ignitions into larger fires.

In reaction to these more extreme conditions, PG&E recently formed an R3+ Ignitions Task Force, specifically looking at which supplemental mitigations could be deployed in the near term to stem the rise in these higher risk R3+ ignitions. A total of 20 mitigations are being contemplated, with approximately half in active deployment and half still awaiting the completion of analysis.

One of the programs being implemented by this Task Force is the removal of vegetation around approximately 50,000 electric poles in high fire-risk areas, primarily in the North Coast, North Valley, and Sierra and Central Valley regions. This is additional pole clearing beyond the 70,000 poles PG&E clears three times per year in high fire risk areas to meet state compliance requirements. PG&E implemented this additional pole clearing following the analysis of 2023 and 2024 HFTD/HFRA PG&E CPUC reportable ignitions which indicated that 47% of these ignitions originated within 10 feet of the base of the pole. Vegetation removal efforts, currently undertaken by a team of 463 personnel, include trimming grass and shrubs within 10 feet of the base of electric poles; clearing limbs, foliage and other vegetation up to eight feet or more above the ground; and hauling away all trimmings and debris.

Other mitigations being led by this Task Force include:

- adding approximately 6,000 additional Gridscope sensors (described in ISM Report 4) to the approximately 4,000 previously installed and planned. PG&E stated that these sensors are designed to address mid-span ignitions which the pole clearing program does not catch;
- clearing vegetation under transmission switches;
- conducting supplemental targeted tree removals;
- adding avian guards on transmission poles;
- adding artificial intelligence enabled high-definition cameras;
- proactive replacement of exempt e-fuse equipment; and
- accelerating infrared tag completions.

Reliability

As described in Prior ISM Reports, PG&E's capital expenditures on reliability-oriented projects dropped over the past ten years, with targeted reliability investments shifted to support wildfire risk mitigation since 2017. While this increased wildfire mitigation spending correlates with a decrease in the number of PG&E facility ignitions in high-risk areas, the reduction in targeted reliability capital, combined with the introduction of the PSPS and Enhanced Powerline Safety Settings (EPSS) programs in 2018 and 2021, respectively, have all contributed to substantial increases in the average duration and frequency of PG&E customer outages over the 2017 to 2023 period as seen in Table 1.

While PG&E files an Annual Electric Reliability Report with the CPUC each year that provides additional background on PG&E's reliability statistics, breakdowns by distribution and transmission systems and districts, and provides commentary on major storm events and reliability trends, the ISM has started to track individual components of reliability that are supplemental to what is provided in these annual reports. With PG&E implementing numerous programs over the past few years (which the ISM has previously reported on) that have the stated aim of improving customer reliability, the ISM will continue to track reliability by sub-cause in order to observe the effectiveness of these reliability mitigations over time.

Table 1 provides a breakdown of the various components of PG&E's System Average Interruption Duration Index (SAIDI), which is the average cumulative minutes of sustained power interruptions during the year. SAIDI is calculated by the total minutes every customer was without power due to sustained outages divided by the total number of customers. As seen in Table 1, average system unplanned outages (including EPSS, but excluding PSPS and Major Event Day storm activity) increased by approximately 119% over this seven year period (from 97 to 213 minutes), putting PG&E in the fourth quartile for SAIDI as compared to all other U.S. based electric utilities.

Table 1: System Average Interruption Duration Index (SAIDI, minutes)[1]

		2017	2018	2019	2020	2021	2022	2023
Non-EPSS Unplanned Outages	3rd Party	16.4	20.6	22.8	26.4	28.8	24.0	23.6
	Animal	4.3	6.4	6.2	6.9	10.5	7.7	5.2
	Company Initiated	1.3	1.1	2.1	8.4	3.8	5.8	2.4
	Environmental / External	3.1	3.7	2.8	4.1	8.9	5.5	4.4
	Equipment Failure / Involved	46.0	43.3	48.0	54.8	73.7	69.4	68.7
	Unknown Cause	7.6	9.9	12.9	14.3	34.2	12.9	15.7
	Vegetation	18.7	14.7	22.4	15.4	22.4	20.1	31.7
		97.3	99.8	117.2	130.4	182.3	145.4	151.7
EPSS Outages	3rd Party						6.8	5.5
	Animal						8.4	5.2
	Company Initiated						1.6	4.3
	Environmental/External						1.2	2.6
	Equipment Failure / Involved						12.4	14.8
	Unknown Cause						28.6	21.1
	Vegetation						7.6	7.8
		0.0	0.0	0.0	0.0	0.0	66.6	61.2
Unplanned Outages (excl. PSPS/MED)		**97.3**	**99.8**	**117.2**	**130.4**	**182.3**	**212.1**	**212.9**
Planned Outages		16.1	26.7	31.1	27.4	35.4	42.0	42.2
Unplanned + Planned Outages (excl. PSPS/MED)		**113.4**	**126.5**	**148.3**	**157.8**	**217.7**	**254.0**	**255.1**
PSPS Outages			16.4	1,061.0	241.6	26.9		1.0
Major Event Day Outages		260.9	183.0	1,246.7	327.7	408.1	70.1	455.8
Total Outages		**374.2**	**325.9**	**2,456.0**	**727.2**	**652.8**	**324.2**	**711.9**
Total Major Event Days (Days/Year)		*30*	*7*	*31*	*14*	*25*	*5*	*20*

As seen in Table 1, EPSS is showing an average SAIDI in 2022 and 2023 of approximately 1 hour.[2] While the fast trip nature of EPSS results in more frequent outages than would occur without EPSS enabled, some outages would still have occurred whether EPSS was enabled or not. As a result, some of the reduction in non-EPSS unplanned outages can be attributed to a shift to the EPSS category.

When including planned outages (but still excluding PSPS and MED), the SAIDI increase over this seven-year period is slightly larger at approximately 125% (from 113 to 255 minutes). PG&E's number of sustained planned outages remained relatively steady since 2018 at approximately 40,000 per year, with planned outage SAIDI increasing from approximately 16 minutes in 2017 to 42 minutes in 2023.

[1] Although the EPSS program began in 2021, its reliability contribution is not broken out separately in Table 1, as EPSS was a pilot program in 2021, limited to a few months and covering a smaller number of circuits than are currently EPSS enabled.

[2] Customers experiencing EPSS outages saw average durations of 176 minutes in 2022 and 193 minutes in 2023. When averaged across PG&E's entire system, which includes non-EPSS enabled lines, EPSS's SAIDI impact is reduced to the figures shown in Table 1.

Table 1 also shows the large annual variability in total average outage minutes that can arise with PSPS and MED outages. In 2022, for example, there were no PSPS events, and few major storm events. As a result, MED outages only added a supplemental 70 minutes to the overall SAIDI figure. In 2019, however, numerous storms, combined with more extreme wildfire conditions, led to a supplemental 2,307 minutes being added to the overall SAIDI figure.

In addition to the increase in the average duration of system outages, PG&E experienced a similar increase in its System Average Interruption Frequency Index (SAIFI), which is the average number of sustained power interruptions during the year. SAIFI is calculated by the number of sustained customer outages experienced by all customers divided by the number of customers. As seen in Table 2, the frequency of unplanned outages (excluding PSPS and MED) has increased by 60% (from 0.9 to 1.4 outages per year) over this seven-year period. When including planned outages (but still excluding PSPS and MED) the frequency increased by 62% (from 1.0 to 1.6). Note that the addition of PSPS and MED outages are not as impactful to SAIFI as they are to SAIDI. This is due to PSPS and MED outages generally being much smaller in number, but often having durations that, in extreme cases, can last several days.

Table 2: System Average Interruption Frequency Index (SAIFI, minutes)

	2017	2018	2019	2020	2021	2022	2023
Non-EPSS Unplanned Outages	0.9	1.0	1.0	1.1	1.2	1.1	1.1
EPSS Outages	0.0	0.0	0.0	0.0	0.0	0.4	0.3
Unplanned Outages (excl. PSPS/MED)	**0.9**	**1.0**	**1.0**	**1.1**	**1.2**	**1.5**	**1.4**
Planned Outages	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Unplanned + Planned Outages (excl. PSPS/MED)	**1.0**	**1.1**	**1.1**	**1.2**	**1.3**	**1.6**	**1.6**
PSPS Outages	0	0.0	0.4	0.1	0.0	0.0	0.0
Major Event Day Outages	0.6	0.1	0.9	0.4	0.5	0.1	0.7
Total Outages	1.5	1.2	2.4	1.8	1.9	1.8	2.2

While PSPS and EPSS have been negatively impacting PG&E's reliability, it is important to observe how PG&E views the mitigation cost/benefit relationship between the positive impacts that these two mitigations have on wildfire risk reduction versus the safety and reliability consequences to its customers from these two programs. The ISM obtained Figure 3 from PG&E's 2024 Risk Assessment and Mitigation Phase (RAMP) Report that was filed on May 15, 2024. Figure 3 shows PG&E's projected 2027 risk value with PSPS and EPSS mitigation and consequence. While the derivation and components of each item in the graph can be found within the RAMP report, the key observation from this Figure is that PG&E is projecting that the wildfire risk reduction from its PSPS and EPSS programs are approximately 3.25 times as large as the combined projected customer safety and reliability risk value impacts.

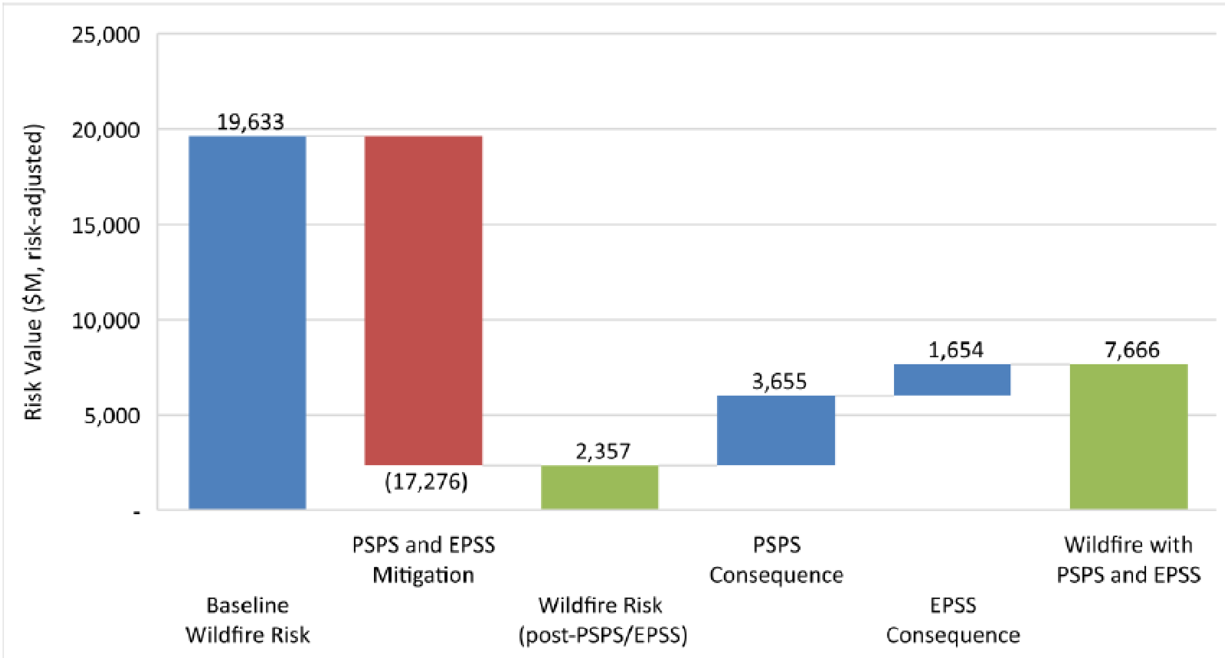

Figure 3: Projected 2027 Wildfire Risk Value with PSPS and EPSS mitigation and consequence

FAST TRIP PROGRAMS

In ISM Previous Reports, the ISM reported on the initiation and maturing of PG&E's distribution Enhanced Powerline Safety Settings (EPSS) program, which includes Downed Conductor Detection (DCD) and Partial Voltage Force-Out (PVFO) enhancements. All of these fast trip mitigations are designed to more rapidly de-energize power lines when conditions that can lead to ignitions are detected. In this Section, the ISM reported its observations related to: (1) reviewing the performance and customer impacts of these fast trip mitigations during the current ISM reporting period versus prior periods, (2) describing PG&E program expansions and modifications, (3) describing PG&E actions that seek to reduce the frequency and duration of fast trip outages, and (4) describing PG&E's new fast trip technologies testing deployment.

Enhanced Powerline Safety Settings (EPSS) Updates

In ISM Report 4, the ISM reported PG&E extended its EPSS coverage to 44,100 distribution miles. This covers 100% of the High Fire Risk Area (HFRA), plus approximately 19,000 buffer area miles selected due to the potential to experience ignitions which could lead to wildfires capable of spreading into the HFRA and to protect system stability. These EPSS enabled lines service approximately 1.8 million customers. PG&E stated that CPUC reportable fire ignitions on EPSS enabled circuits were reduced by approximately 72% in 2023, 68% in 2022 and 74% in 2021, versus the three-year average for the 2018-2020 period, prior to EPSS enablement. For weather normalization, PG&E used historical meteorological data and EPSS enablement criteria to determine which of the circuits during that 2018-2020 period would have been enabled, had EPSS been in effect at that time.

ISM Previous Reports also provided information on the expansion of EPSS capability on certain eligible transmission lines. For the first 8 months of 2024, PG&E enabled EPSS on an additional 8 transmission lines (bringing the total to 56 out of the 75 transmission lines that are eligible for EPSS enablement) with 5 additional installations planned during the final four months of 2024.

Table 3: EPSS Data January to August 2023 vs 2024

	Jan to Aug 2023	Jan to Aug 2024
EPSS Outages	1,236	1,544
Ignitions on EPSS Enabled Lines	12	29
EPSS CAIDI (min)	204	150
Response Time Within 60 minutes	90.0%	93.0%
Average Full Restoration Time (min)	371	421
% Restorations <= 60 minutes	8.7%	11.9%
% Restorations >= 12 hours	16.7%	13.6%
Total Customers Experiencing EPSS Outages	1,150,390	1,270,293
Unique Customers Experiencing EPSS Outages	550,518	626,334
Medical Baseline Customers	76,056	74,465
Life Support Customers	53,871	53,869
Critical Customers	19,356	20,998
Schools	2,549	2,423
Hospitals	148	136
Well Water Dependent Customers	2,444	3,576
Outage Cause (% of total)		
3rd Party	9.0%	9.8%
Animal	12.9%	11.6%
Company Initiated	7.6%	11.8%
Environmental/External	1.8%	1.4%
Equipment	13.9%	13.5%
Unknown	42.6%	39.2%
Vegetation	12.2%	12.6%

Table 3 provides a comparison of certain EPSS performance metrics between January 1 to August 31, 2023 versus the same period in 2024. Table 3 shows an increase in the number of EPSS outages, reportable fire ignitions on EPSS lines, and customers experiencing EPSS outages during the first eight months of 2024 versus the same period in 2023. As noted in the Ignition and Reliability Trend section of this ISM Report 5, the first 8 months of 2024 experienced more extreme fire potential conditions than during the same period in 2023. As such, EPSS circuits were enabled more frequently when minimum threshold conditions were met, with EPSS enablement over the first 8 months increasing from approximately 3.0 million circuit mile days in 2023 to approximately 3.8 million circuit mile days in 2024.

These more extreme weather conditions, combined with the increase in EPSS circuit mile days (where ignitions would have had a greater probability of occurring on lines which were EPSS enabled at the time of the ignition), also led to the increase in ignitions on EPSS enabled lines from 12 in 2023 to 29 in 2024 over the comparable eight month period (compared to 27 as the annual average during the 2022-2023 period). PG&E's average response time for the 2024 ignitions was 37 minutes, versus 47 minutes for the 2023 ignitions for the comparable period. Of the 29 ignitions on EPSS enabled lines in 2024, the most frequent suspected causes were vegetation contacts (16 ignitions) and equipment failures (7 ignitions).

The increase in EPSS enablement in 2024 contributed to an increase in the number of outages. Outages for the first 8 months increased from 1,236 in 2023 to 1,544 in 2024, an increase of approximately 25 percent. However, normalized by the number of circuit mile days EPSS was enabled, the outages increased marginally from 42.6 outages per 100 thousand circuit mile days compared to 43.1 outages per 100 thousand circuit mile days.

The increase in EPSS enablement in 2024 also contributed to an increase in the number of customers experiencing multiple EPSS outages. For the first 8 months of 2024, approximately 626,000 customers experienced one or more EPSS outages, with nearly 36,000 of these experiencing five or more outages (versus approximately 542,000 and 45,000 outages respectively for the comparable period in 2023). The highest number of EPSS outages on a single circuit segment was 7 during 2024 versus 6 for the comparable period in 2023. The average number of customers experiencing each EPSS outage in 2024 was 824, which was below the 2022-2023 average of 881.

Several programs implemented by PG&E aiming to reduce EPSS related customer impacts have been detailed in ISM Previous Reports. One of PG&E's objectives is to reduce the average duration of the EPSS outages. Several metrics show continued improvement in this area, including an increase in the percentage of time PG&E is able to have personnel at the site within 60 minutes of the outage (increased from 90% to 93%), the percentage of full power restorations made within 60 minutes (increased from 8.7% to 11.9%) and the Customer Average Interruption Duration Index (CAIDI) which decreased 26% (from 204 minutes to 150 minutes) for the eight month comparative periods.

One PG&E program aimed at minimizing customer impacts is adding more line sectionalization, which helps isolate an EPSS outage to shorter circuit segments, which in turn allows for faster restoration of service for more customers. In addition to the 209 sectionalizing devices that were installed by the end of 2023, PG&E added an additional 125 devices during the first 8 months of 2024, and plans on installing an additional 101 devices by the end of 2024.

Another approach utilized by PG&E to reduce its customer EPSS impact is through improvements in its workforce planning and resource allocations in response to EPSS events. PG&E detailed these approaches in its 2025 Wildfire Mitigation Plan Update – ACI PG&E-23-13 (April 2024) and includes (1) the use of a Storm Outage Prediction Project model to help stage patrol and restoration resources in advance of anticipated storm events, (2) the staging of helicopter assets throughout PG&E's service territory, (3) a plan to surge staffing when necessary, using internal and contract inspection personnel, and (4) shifting PG&E local teams from planned work to outage response when high volumes of customers are out for extended durations.

PG&E also seeks to reduce the number of EPSS outages caused by animal and vegetation contact through its Animal Mitigation and Vegetation Management for Operational Mitigation (VMOM) programs, which focus on supplemental reliability mitigations on circuit segments which have historically seen higher numbers of EPSS outages by these two causes. Both programs were detailed in Previous ISM Reports, with the VMOM program further detailed in the Vegetation Management section of this ISM Report 5. In addition to the 132 animal mitigations installed in 2023 under this supplemental EPSS program, PG&E added an additional 1,508 during the first 8 months of 2024, and plans to add approximately 330 more by the end of 2024. For the proactive portion of the VMOM program, PG&E completed work on approximately 4,900 trees out of its 5,000 tree WMP commitment for 2024 (versus 8,185 trees worked under this program in the full calendar year 2023). For the reactive VMOM program, which involves conducting extent of condition patrols adjacent to the location of current-year vegetation caused EPSS outages, PG&E trimmed an additional 644 trees in the vicinity of the 207 vegetation caused EPSS outages in the first 8 months of 2024.

Other Fast Trip Program Updates

Downed Conductor Detection (DCD) EPSS Program Enhancement

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

During the current ISM reporting period, the ISM observed PG&E continued installation of additional DCD devices, adding an additional 359 devices in 2024, bringing the total installed devices to 1,305. PG&E's target is to install an additional 81 devices by the end of 2024, which would bring the total number of devices to 1,386, giving coverage to approximately 20,500 miles in HFRA that are DCD capable. PG&E states that this will leave approximately 2,000 HFRA miles still available for DCD expansion in 2025 and beyond, and that the remaining 3,000 HFRA miles will be ineligible, as DCD is currently only possible on 3-wire circuit configurations, which these remaining miles do not have. PG&E's prioritization of the installations was based upon the circuit risk ranking from its Wildfire Distribution Risk Model v3.

During the current ISM reporting period, the ISM observed there were approximately 181 DCD outages through July 25, 2024 (versus 330 in the full calendar year 2023), with the largest causes being 42% Unknown, 34% Company Initiated, 10% Equipment Failure, and 7% Vegetation.

This 34% Company Initiated percentage is comparable to the 37% experienced in 2023. PG&E previously informed the ISM that these Company Initiated trips are mostly "nuisance trips" caused by problems with software algorithms in the devices as the DCD program was scaled over the larger number of devices in 2023. PG&E also informed the ISM in 2023 that it was working with the manufacturer on firmware updates that could be installed into the devices. This firmware upgrading has commenced, with PG&E completing 40 of the 500 installations planned for 2024.

As a result of post-outage patrols, PG&E identified 22 line-to-ground fault-type incidents through July 29, 2024 where DCD likely mitigated ignitions (9 associated with vegetation contacts, 7 with equipment failures and 6 with customer equipment, bird, and vehicle contact).

Partial Voltage Detection (PVD) / Force Out (PVFO) EPSS Program Enhancement

The other EPSS program enhancement PG&E began implementing in mid-2022 was the PVD/PVFO program, which covers approximately 90% of HFRA miles. This SmartMeter™ based program, which can send real time alarms when partial voltage or full/partial loss of phase is detected, was described in ISM Report 3.

PG&E experienced 9 PVFO outages through July 29, 2024 (with 7 field hazards identified), slightly down from the 12 outages (with 11 field hazards identified) that occurred during the same time period in 2023. For comparison, PG&E experienced 25 PVFO outages for all of 2023 and 36 for all of 2022. PG&E's average response time for the 2024 outages was 17 minutes, slightly up from the 15 minutes experienced during the same period in 2023.

New Fast Trip Technologies

During the current reporting period, PG&E continued to advance the development of several new fast trip technologies.

Rapid Earth Fault Current Limiter (REFCL)

PG&E is currently conducting a test of the REFCL system on its 160 mile, 12kv Calistoga line in North Napa. REFCL was originally implemented in Australia, works best with 1 or 2 phase line to ground faults, and attempts to create a system that minimizes arcing to the ground by neutralizing ground faults within a 30-millisecond period. PG&E experienced several challenges in adding this new technology to its legacy distribution system, requiring additional upgrades, tuning, testing, and training. Commissioning delays also included equipment failure, the extended lead time of equipment, and the need to procure additional equipment to further stabilize the system. PG&E informed the ISM that the system has now been tested and is expected to be enabled in trip mode shortly.

PG&E's plan is to test the system at Calistoga only through the balance of 2024, then review the results over the winter period before determining whether to expand the program. PG&E stated that an important outcome would be to validate the estimated ignition mitigation effectiveness of this additional layer of protection (estimated at 65% for EPSS + DCD + REFCL) and to generate implementation costs for any expansion.

Falling Conductor Protection (FCP)

FCP is defined as a protection scheme that attempts to de-energize a broken wire before it contacts the ground (or shortly thereafter) to prevent an ignition. FCP would be a further enhancement to PG&E's EPSS program that seeks to mitigate distribution falling conductor related ignitions through the algorithmic based high impedance ground fault downed conductor detection (DCD) capability and the SmartMeter based partial voltage detection program.

PG&E informed the ISM that it is in the early stages of evaluating this technology, and that the number and location of test circuits have not yet been selected. FCP requires an extensive network of sensing devices and communication links, which PG&E stated can be difficult to implement at scale on a distribution system in highly forested terrain. PG&E also indicated that every lateral branch of a circuit would need a sensing device at the end of the line to be able to detect broken wires before they contact the ground (or shortly thereafter), which PG&E believes would be cost prohibitive. Finally, PG&E stated that the majority of its CPUC reportable ignitions within HFRA occur because of vegetation contact or other external contact, which FCP cannot always mitigate.

Despite these obstacles, PG&E indicated that in certain strategic and high-risk locations, it may be possible to selectively implement FCP to provide coverage for a targeted section of distribution overhead circuitry.

PG&E is currently in the early stages of a pilot initiative to attempt to provide FCP online reclosers over existing cellular connectivity (available in approximately 75% of HFTD/HFRA) to determine the overall feasibility of this type of solution. PG&E will evaluate lessons learned, such as cellular connectivity latency, device compatibility, and ignition mitigation effectiveness as part of this effort.

Early Fault Detection (EFD) / Distribution Fault Anticipation (DFA)

EFD and DFA are risk reduction technologies that are incremental to system hardening, and that reduce risk through the maintenance and replacement of assets identified by the EFD and DFA sensors. Using sensors that monitor the radio frequency spectrum, the EDF system detects the generation of partial discharge (PD) which can be an indicator of equipment electrical degradation or arcing. Using measured accumulation of PD, the system can then identify the location of these issues (such as broken conductors or cracked insulators). DFA looks for current/voltage power flow anomalies to detect faults and abnormal power flow events (such as loose conductors that may be slapping). PG&E indicated that while these are conditions that should also be picked up by field inspections, with continuous monitoring and possible early detection, these technologies may find defects that ground and aerial inspections may miss. PG&E also stated that while EFD and DFA have the capability of identifying the location where an incipient fault may occur, it cannot yet predict when the fault will occur, and minor damage could result in a high number of detections that could last multiple years.

PG&E shifted from pilot evaluation of these technologies to production in 2023, with 103 EFD units installed across two high risk circuits in the North Bay area totaling approximately 240 miles. PG&E plans to install an additional 200 EFD units in 2025 across four additional circuits.

PG&E is also working on a 3-year WMP commitment (with a completion date of December 31, 2025) to perform a feasibility study on the use of EFD/DFA technologies to successfully identify incipient failures as a supplement to field inspections. If feasible, PG&E would then be required to complete a data driven proposal for integrating sensor findings into the inspection program.

RISK MODELS

Distribution and Transmission Risk Model Updates

In the ISM Previous Reports, the refinements of PG&E's wildfire risk models over the past five years were discussed, and details were provided on enhancements incorporated into in the latest version of the Wildfire Distribution Risk Model Version 4 (WDRM v4) and the Wildfire

Transmission Risk Model Version 2 (WTRM v2). To calculate the total wildfire risk associated with each PG&E facility, the ignition probabilities generated by these two models are multiplied against the projected consequences of an ignition occurring at specific asset locations, which are derived from a separate Wildfire Consequence Model Version 4 (WFC v4).

In ISM Report 4, the ISM reported that PG&E was still evaluating how and when these latest versions of the risk models would be used to guide future wildfire mitigation workplans. It was noted in the report that one issue that PG&E needed to consider was the discrepancy between the frequency with which the risk models were being updated (e.g. WDRM v1 (2019), v2 (2021), v3 (2022), v4 (2024)), versus the several years it often took to plan, design, estimate, permit and construct asset enhancements and line rebuild projects (like undergrounding). To address this timing mismatch, to avoid having to accommodate more frequent changes to circuit risk rankings, and to provide for better alignment with its 3-year Wildfire Mitigation Plan (WMP) and general rate case cycles, in August 2024 PG&E leadership approved a plan to have WDRM v4 and WTRM v2 be used to guide the entire 2026 to 2028 WMP cycle.

PG&E stated that these risk models will continue to see improvements in data inputs, added risk factors and refinements of model functionality to improve model accuracy over time, but that the outputs of WDRM v4 and WTRM v2 will be used for its 2026 to 2028 wildfire mitigation planning.

One such set of enhancements to PG&E's transmission risk modeling was also approved by PG&E leadership in August 2024. This involved four updates to its Operability Assessment (OA) model. The OA model focuses on conditional probability of failure in high wind conditions, is used in Public Safety Power Shutoff (PSPS) planning and is a component of the WTRM v2 model.

These updates include:

- modifying the design life reduction factor for poles which have received several different types of gas treatment;[3]
- lowering the modeled remaining strength for reinforced poles from 92% to 67% based on feedback from PG&E's pole test and treat inspectors;[4]
- combining pole test and treat wood strength scores (which rates decay at the base of a pole) with inspection codes that can identify pole strength issues (such as woodpecker damage) higher up in the pole;[5] and
- updating the modeling of outages on transmission tap lines.[6] The updated model uses past wind speed and outages on the main lines to adjust the possibility that outages on

[3] This resulted in a higher probability of failure for approximately 2,000 wood poles.

[4] This resulted in lower remaining strength for approximately 1,900 wood poles.

[5] This resulted in reduced remaining strength for approximately 5,300 poles.

[6] Outages for some tap lines have been charged to the main line, which PG&E stated could result in optimistic model results for these tap lines, since it can appear as if no outages have occurred on the lines (note: 290 of the 540 tap lines record zero outages).

the main line were actually caused by tap lines.

PG&E also reviewed the impact that these OA model changes would have on PSPS guidance. Using what PG&E considers to be a worst-case scenario where PG&E's entire service territory was experiencing high wind speeds and high fire potential index scores, these model changes resulted in approximately 1,800 more structures being included in PSPS scope (note: for scale, PSPS in-scope under these modeled conditions were approximately 39,000 structures out of a total population of approximately 136,000 transmission structures).

Fire Science 5.0 and PSPS 5.0 Guidance Updates

During the current ISM reporting period, enhancements for multiple predictive fire science models and updates to PSPS threshold guidance were approved by PG&E leadership in July 2024, with operational effective dates of August 1, 2024.

The updated fire science models include:

- Fire Potential Index Model (FPI 5.0);
- Outage Probability Weather Model (OPW 5.0);
- Ignition given Outage Probability Weather Model (IOPW 5.0);
- Ignition Probability Weather Model (IPW 5.0) = OPW 5.0 x IOPW 5.0; and
- Catastrophic Fire Probability Distribution (CFP_D 5.0) Model = IPW 5.0 x FPI 5.0

Summaries of each of these models, their usage, and their history of enhancements can be found in PG&E's 2023-2025 WMP, and most recently in PG&E's 2025 Wildfire Mitigation Plan Update (April 2, 2024) in Section ACI PG&E-23-25 – Fire Potential Index and Ignition Probability Weather Enhancements.

Since each of these models are key in setting PSPS and EPSS decision making, in order to minimize the risk of any technical issues prohibiting the use of the new models, PG&E stated that it will continue to keep Version 4.0 of these models active through the end of 2024 as a back-up.

Over the past few years, the ISM observed the creation and expansion of several foundational tools used to support PG&E's fire science programs. In the ISM Previous Reports, the ISM discussed the refinements of PG&E's wildfire risk models over the past few years. PG&E's modeling now incorporates a 35-year historical climatology data set (August 1989 to December 2023), updated annually, with the same 2 x 2 km hourly resolution as used in the forecast models. Weather modeling is now done on a 129-hour forecast horizon and uses eight weather forecast members in the current ensemble configuration.[7] Other inputs for modeling and calibration include satellite fire detection and sub-daily wildfire growth data, PG&E ignitions and outages, CAL FIRE Damage Inspection Program data, Red Flag Warnings, PG&E circuit geometries, and PG&E customer counts.

PG&E also utilizes several fuel moisture models which factor in data on dead fuel moisture and

[7] Four using the National Center for Environmental Prediction GFS model, and four using the European Center for Medium-Range Weather Forecasts (ECMWF) Forecasting model.

herbaceous and woody live fuel moisture. One new fuel metric introduced into the Fire Science 5.0 modeling and the PSPS 5.0 Guidance is the Normalized Difference Vegetation Index (NDVI). NDVI is routinely measured by satellite and tracks the seasonal cycling of the grass-crop. PG&E stated that this index allows them to better differentiate when the grass crop shifts from healthy green to brown/cured, which is a strong signal of the transition to a higher risk wildfire environment.

During the current ISM reporting period, the ISM also observed PG&E's development and use of a new PSPS calibration dashboard, which brings together the large quantities of historical meteorological, fire and ignition data into one visual dashboard. PG&E stated that this dashboard assists in performing more rapid sensitivity and calibration analysis, provides simplified views of customers impacted and circuit miles per event, and allows for the review of historical fire outbreaks and past PSPS events down to an hourly level. This dashboard is also designed to compare the frequency, scope and magnitude of PSPS events, customer impacts and timing, and location of events to past fire events by adjusting various PSPS guidance thresholds.

Key Fire Science 5.0 enhancements observed by the ISM include:

- new soil moisture, solar radiation, fuel bed depth, and fuel complexity inputs into FPI 5.0;
- a five-fold enhancement in spatial resolution in FPI 5.0, going from a 2 x 2 km (4 km^2) grid to 0.7 km^2 hexagons, which adds more granularity for topography, microclimate and vegetation changes;
- added pole age and annual satellite-derived tree heights and canopy cover of strike trees, added wind turbulence to enhance explanations of wind caused outages, and improved the spatial resolution of outages in its OPW 5.0 model;
- recent years exponentially weighted more heavily in the OPW 5.0 model to learn and predict system performance changes, including positive changes from vegetation management and system hardening, and negative changes from asset degradation and tree mortality; and
- added EPSS enablement into the IOPW 5.0 model and expanded its coverage from HFTD to covering all of PG&E's service territory.

PG&E also provided data which showed that each model exhibited an improvement in predictive ability over the 4.0 versions of the models.

In order for a PSPS event to be considered, PG&E first examines whether the certain Minimum Fire Potential Conditions (mFPC) may be met. These mFPC parameters are shown in Figure 4, which highlights the changes that occurred between PSPS Guidance Versions 4.0 and 5.0.

Parameter	Current Protocols (PSPS 4.0)	Proposed Protocols (PSPS 5.0)
Fire Potential Index (FPI)	>0.7 (FPI 4.0 Probability Large or Catastrophic)	**>0.22** (FPI 5.0 Probability Catastrophic)
Wind Speed Sustained (mph)	>19	>19
Relative Humidity	<30%	<30%
Dead Fuel Moisture 10hr	<9%	<9%
Dead Fuel Moisture 100hr	<11%	**<12%**
Dead Fuel Moisture 1000hr	<11%	**Not Used**
Live Fuel Moisture - Chamise	<90%	**Not Used**
NDVI (Vegetation Health)	**Not Used**	**<0.36**

Figure 4: Minimum Fire Potential Conditions Required to Consider PSPS Event

PG&E indicated that the larger change in the FPI threshold between PSPS 4.0 and PSPS 5.0 is due to the values between the two FPI 4.0 and 5.0 models not being equivalent. This is due to the new FPI 5.0 model incorporating more fire size classifications and being calibrated against the wind driven catastrophic class.[8] Although PG&E removed two fuel moisture metrics (dead fuel moisture 1,000 hour, and live fuel moisture (chamise)) from the mFPC in PSPS 5.0, PG&E indicated that these two metrics continue to be used in the distribution and transmission models themselves, but that the new NVDI metric is a much stronger guide to vegetation health and condition.

In its presentation to PG&E leadership, the fire science team provided benchmarking on the mFPC set by other utilities as part of their PSPS guidance and provided graphs highlighting the PSPS 5.0 Guidance levels for each metric against the conditions that existed during larger historical fires. In most instances, the PSPS 5.0 thresholds would have triggered PSPS events for historical catastrophic fires. The exception is for minimum sustained wind speed, where PG&E stated that many large fires started under low wind speed conditions, and that sensitivity studies show that several weeks of PSPS events per year would be required to mitigate these incidents since the conditions are quite common.

PG&E will consider calling a PSPS event if the mFPC in Figure 4 are met, and if any of the three conditions in Figure 5 for a minimum event size are also met. A PSPS event will typically not be considered until guidance is met for a minimum size of approximately 100 km^2. PG&E stated that the floor on event size was set to avoid small geographic areas with short durations that can arise. During fire season, for example, PG&E noted that small areas routinely meet mFPC and PSPS criteria in localized areas (typically due to afternoon sea-breeze in the interior where it's hot and dry).

[8] The wind driven catastrophic class is the most dangerous class in the model.

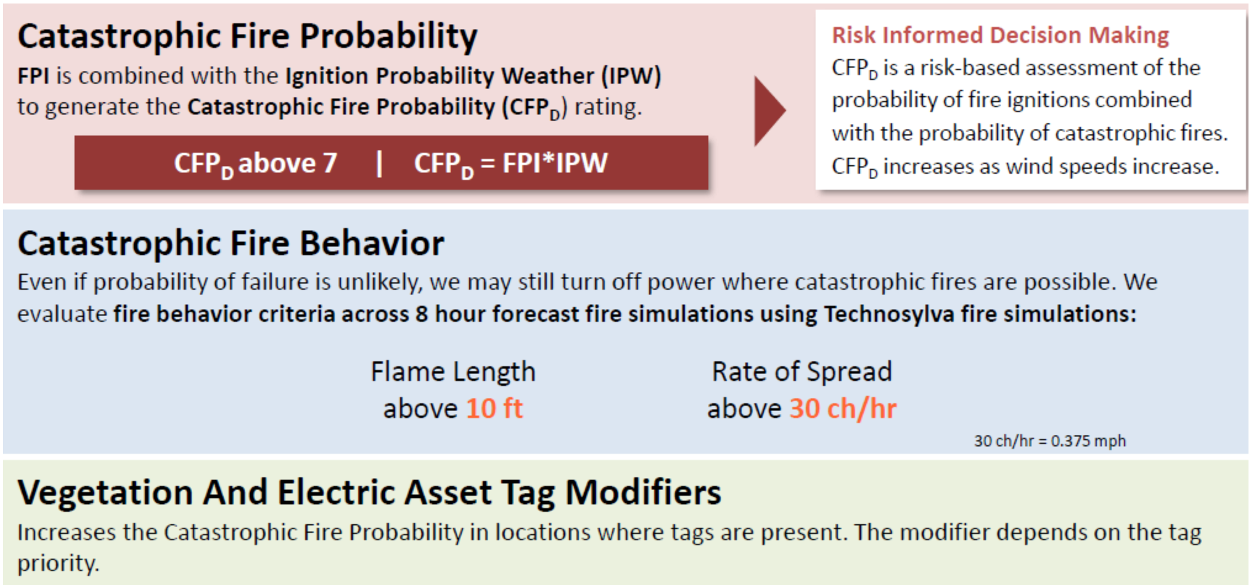

Figure 5: PSPS Guidance 5.0 Criteria

The key changes from PSPS 4.0 to PSPS 5.0 for the three criteria shown in Figure 5 are:

- Catastrophic Fire Probability: shift from CFP_D from greater than 9 to greater than 7 to factor in FPI 5.0 modeling changes and to capture more wind driven fire risk;
- Catastrophic Fire Behavior: shift from 2-hour to 8-hour fire simulations (which provides more consistent modeling output), resulting in the minimum flame length shifting from 8 to 10 feet, and the rate of fire spread increasing from 20 chains/hour (equivalent to 0.25 mph) to 30 chains/hour. PG&E also expanded the historical simulation climatology from the 600 worst fire weather days to greater than 2,000 worst fire weather days; and
- Vegetation and Electric Asset Criteria Considerations: In the original versions of PSPS guidance, PG&E adjusted its CFP_D upwards by adding a tag modifier that factored in higher priority asset- and tree-tags that may exist within a modeled cell. In PSPS 4.0, this modifier was then expanded to cover whether any tags existed within a modeled cell. Since approximately 95% of all hexagons contain tags, for PSPS 5.0, PG&E elected to further adjust the modifier, so that the hexagon receives an upward adjustment, the magnitude of which is dependent on the priority level of the highest priority asset or tree tag in that hexagon.

In reviewing the impact of these PSPS 5.0 guidance changes, and to guide the setting of the various guidance levels, PG&E conducted more than sixty sensitivity studies to analyze wildfire risk mitigation and customer impacts of PSPS on an hour-by-hour basis at the finest resolution of the model. PG&E also modeled the PSPS event circuit frequency over a 16-year historical period (2008-2023) and found that the areas most frequently impacted by PSPS 5.0 guidance are consistent with the highest wildfire risk locations in offshore wind events, and are generally matching previous PSPS 4.0 models and guidance. Further, PG&E did a side-by-side comparison of the largest 15 back-casted PSPS events over this same 16-year period, comparing the customer count and event duration of PSPS events that would have occurred using the PSPS 4.0 and PSPS 5.0 guidance levels. During this back-casting, PG&E found that the largest historical PSPS events remained approximately the same size and duration between the two guidance levels, while the smaller events incurred larger percentage variations, both positive and negative between the two. Overall, PG&E stated that between the improved predictive ability of the Fire Science 5.0 models, the enhanced FPI model granularity, and the adjusted PSPS Guidance, PSPS 5.0 is better at mitigating wildfire risk for a given PSPS event size.

Equipment Failure Models

Over the past two years PG&E examined whether additional machine learning models could be developed using existing utility data sets to predict electric distribution equipment failures and outages so that corrective action could be taken before either could occur.

PG&E stated that its base model was found to have a strong ability to successfully identify voltage related anomalies with the transformer. PG&E also indicated that while it could identify transformers operating outside of operational standards, the base model struggled to precisely predict when a transformer would fail, making it difficult to properly prioritize replacement of transformers that have a high risk of failure.

In 2023, PG&E continued to make improvements to the model to improve its predictive accuracy. These improvements included:

- incorporating transformer oil temperature and transformer aging calculations;
- incorporating additional years of data for model training; and
- labeling more transformer outages to provide additional input to the training model.

PG&E is continuing to test the accuracy of the model's ability to predict transformer failures, and if the accuracy level enables PG&E to achieve beneficial risk spend efficiency, it has stated that it will look to operationalize this model.

DISTRIBUTION INFRASTRUCTURE

In 2024, PG&E introduced several key changes to its distribution inspection and maintenance processes, streamlining its checklist to five broader questions, amending inspection standards through an updated Job Aid, and providing related training to its inspection workforce. PG&E continues to expand the use of drone-based aerial inspections, particularly in High Fire Threat Districts, and has continued its implementation of the Comprehensive Pole Inspection program. The following discusses the ISM's distribution infrastructure observations.

Distribution Inspection Training

In 2024, PG&E reported that distribution ground inspections are performed solely by PG&E employees, with no contract support being utilized in non-High Fire Threat Districts (non-HFTD) and select HFTD. Inspector training in 2024 focused on the California Public Utilities Commission's General Order 165 (GO 165) inspection requirements. The ground inspections this year will primarily take place in non-HFTD, as PG&E already inspected assets in HFTD regions within the five-year window required by GO 165. However, as mentioned in the ISM Report 4, inspections will continue in HFTD areas using a mix of contract and PG&E employees on a risk-based approach. PG&E will conduct almost all inspections of assets in HFTD utilizing its drone inspection program in 2024.

PG&E trained its inspectors on the revised distribution inspection checklist for 2024 discussed in the ISM Report 4. The revised checklist puts more focus on poles, crossarms, conductors and equipment. Guy wires and associated anchors, as well as Vegetation Management ("VM") issues, are not specifically called-out on the checklist but PG&E expects these items to be accounted for under "Additional Conditions" issues. The iPad-based checklist starts with broad questions that expand to include more detailed questions based on inspector response to questions. For example, if the inspector checks that a transformer is present, the checklist will expand to include more detailed questions regarding transformers. PG&E's inspector's iPad include interactive access to the PG&E Overhead Assessment Job Aid - Rev 12, effective February 1, 2024 (Distribution (D_x) Job Aid), discussed below, so inspectors can refer to the D_x Job Aid as needed in the field.

Distribution Inspections

PG&E adjusted its distribution inspection program to incorporate an amended checklist and updated Dx Job Aid. According to PG&E, the new criteria, such as the "X Tag," and more flexible tag prioritization are intended to better address infrastructure risks, as summarized in the following.

Changes to PG&E's Inspection Checklist

PG&E significantly changed the distribution inspection checklist from 2023 to 2024. The 2023 checklist contained detailed questions which were categorized by structure, conductor, equipment, anchors and guys, hardware and framing, vegetation, and other. Each question within these categories was defined with acceptance criteria in the D_x Job Aid. The D_x Job Aid is periodically updated to reflect any changes in inspection requirements or regulatory requirements. The 2023 form of checklist is similar to the checklists used beginning with the Wildfire Safety Inspection Program which started in 2019.

The 2024 checklist was streamlined to contain only five questions as follows:

- Structure – Is the structure damaged, broken, rotten, cracked outside what would be considered normal, leaning beyond 10% or presenting any other compelling abnormal structure conditions?
- Crossarm – Are there any compelling abnormal crossarm, insulator or cutout conditions?
- Conductor – Are there any compelling abnormal conductor conditions?
- Equipment – Are there any compelling abnormal equipment conditions?
- Additional Conditions – Are there any other compelling abnormal conditions or progression of known compelling abnormal conditions?

While these questions are general in nature, the checklist is provisioned to include additional "sub-questions" to provide additional detail for potential tag conditions. Additionally, the inspectors are required to follow the provisions of the current D_x Job Aid. The D_x Job Aid has evolved since 2019 with more content, examples and photographs with some examples detailed below. While the actual inspection checklist is only 5 questions, inspectors are still required to inspect at the same level of detail as previous years and consider the detailed requirements of the 292-page Job Aid.

Job Aid Revisions

During the current ISM reporting period, the ISM reviewed the changes that occurred between the 2023 D_x Job Aid and the 2024 D_x Job Aid. Certain items included in the 2023 D_x Job Aid, such as Raptor Concentration Zone (RCZ) Guidance and PCB Transformer guidance, were not carried over to the 2024 version. In contrast, new items were introduced, including:

- Introduction of an "X Tag" designation.
- Clarification on whether certain equipment on a pole is inspected by ground or aerially.
- Guidance on flashed insulators on transformers.
- Criteria for poles with significant reduced circumference.

Most sections of the 2024 D_x Job Aid allow for inspections to be carried out via both ground and aerial.

Changes in Tag Prioritization

The most notable change between the 2023 and 2024 D_x Job Aids is the adjustment in priority for various tags. The D_x Job Aid provides many specifics for what is required for a minimum tag to be assigned but the tag priority may also be adjusted based on level of exposition, for example:

- Tree Growth: In 2023, trees growing into bare open wire secondary or service lines when no strain or abrasion is present received an "E Tag." In 2024, this condition no longer qualifies for an “E Tag.” PG&E based this change on a PG&E analysis, in which PG&E shows minimal ignition risk from tree contact with secondary open wires.
- Broken Pole: A pole broken at the middle section received a "B Tag" in 2023, but in 2024, the same condition may now warrant a lower priority "E Tag," depending on exposure.[9]
- Loose Lashing: Loose lashing of a third-party cable, which could whip into power lines, was previously assigned an "A Tag" in 2023. In 2024, this was downgraded to a lower priority "X Tag," depending on exposure.[10]

The 2024 D_x Job Aid allows for flexibility in adjusting tag priorities based on conditions observed in the field. While the ISM observed that the minimum tag assigned for some of these conditions may have been given a lower priority, PG&E gives its inspectors the latitude to increase tag priority depending on exposure. Such factors include public exposure, ignition risk, environmental concern, or other extenuating circumstances the inspector deems worthing of increasing tag priority.

Shift to Aerial Inspections

As was detailed in ISM Report 4, PG&E is transitioning from distribution ground to aerial

[9] See PG&E’s 2024 Distribution Job Aid, pg. 49.

[10] See PG&E’s 2024 Distribution Job Aid, pg. 281.

inspections as part of its broader strategy to increase efficiency in its infrastructure assessments, specifically in High Fire Threat Districts. This shift leverages drone technology to capture high resolution images of poles including crossarms, conductors, equipment and insulators, allowing inspectors to review potential issues from a desktop environment. Drones are equipped with high-resolution cameras that take between 7 and 30 photos per distribution inspection, which are then reviewed by Qualified Electrical Workers (QEWs) followed by Inspection Review Supervisors (IRS) within a few days after the photos are captured. In speaking with some of the inspectors, they indicated that this transition helped reduce inspector fatigue in the field. While aerial inspections provide other advantages, such as reducing the need for property access and improving customer relations, there are limitations. Drones are more challenged at capturing tree connections, anchors, or ground-level issues, which are critical for ensuring comprehensive safety assessments. For compliance purposes, PG&E plans to complete a GO 165 ground inspection every five years to meet the 5-year requirement. Additional information can be found in the ISM Field Inspection section.

PG&E began its HFTD distribution aerial inspection in March 2024, and through mid-August completed approximately 140,000 of the 220,000 inspections planned for 2024. Information on PG&E's risk-informed annual aerial inspection workplans and multi-year aerial inspection cycles in HFTD was provided in ISM Report 4.

X Tag Implementation

ISM Report 4 provided an overview of PG&E's plans for introducing new "X Tags" to its maintenance tag priority classification system in 2024. These new "X Tags" are for Level 2 conditions that require completion within 7 days and are situated in priority between A and B tags. Unlike a Level 1 "A Tag", which requires PG&E staff to remain on site until the repair is initiated, PG&E stated that the longer repair time allowed for lower priority and less urgent "X Tags" helps prevent work crews from being diverted from ongoing projects for immediate "A Tag" repairs. PG&E also stated that "X Tags" provide flexibility and greater efficiency by allowing the "X Tag" work to be bundled with other work that may be related to the same assets or in the same area, and by providing customers with more advance notice of planned de-energizations.

PG&E initiated its new "X Tag" program with a pilot starting on March 15, 2024 to ensure that the reporting technology was functioning properly, before the full go-live on March 25, 2024. The total "X Tag" count through August 16, 2024 was 3,142 tags, with an average time to compete of 2.4 days.

During this initial period, PG&E reported to the ISM that twenty-two of the "X Tags" missed their 7 day required completion date. Sixteen of these were late (with an average completion time of 17 days and a maximum of 54 days) due to an IT synchronization issue that occurred between inspector iPads and PG&E's SAP IT system. PG&E reported that the iPad synchronization issue was first reported on June 25, 2024, and that the issue occurred when the iPads were in areas of low- or no-network, or in airplane mode. PG&E further stated that a synchronization fix (which locks out inspectors from further inspections the next morning if the synchronization has not occurred) was created, tested and put into production in late August 2024. The remaining six late "X Tags" had an average completion time of 9 days, and a maximum of 10 days. PG&E provided the ISM with information on each overage, which included issues relating to workforce coordination, work starting late on the final day due to scheduling delays and continuing into the following morning, and issues surrounding load coordination during the July 1 heat event.

Tag Reassessment Programs

Following the implementation of PG&E's Wildfire Safety Inspection Program in 2019 and the build-up of PG&E's unaddressed distribution tag backlog, PG&E implemented the Field Safety Reassessment (FSR) program in 2020. PG&E initiated the FSR program as a containment measure to identify any maintenance tags whose condition may have escalated in severity, and which may require more urgent remediation. Under this FSR program, time-dependent notifications were reviewed annually to see if any escalations in tag priority were required, and separate FSR ground inspections were performed on assets with existing tags that were not scheduled to have any inspections performed on them in that year.

In April 2024, PG&E leadership approved (1) a measure to replace the existing distribution FSR program with an enhanced version of the Comprehensive Pole Inspection (CPI) program, (2) the criteria for the enhanced CPI program, including the expanded tags eligible for CPI and (3) the annual requirement to perform CPI on eligible tags in Extreme, Severe and High consequence locations.

As part of its justification for the retirement of the FSR program, PG&E stated that since the growth of its tag backlog beginning in 2019, PG&E implemented multiple programs that enable its assets, including those with open tags, to fail more safely. These include PSPS, EPSS, and DCD. In addition, PG&E stated that it already carries out many patrol activities outside of CPI, and detailed inspections that also have an ability to "put eyes on assets" with open tags. These include vegetation management patrols, PSPS patrols, EPSS patrols, GO 165 patrols, and a 2024 aerial patrol pilot (covering approximately 20,000 structures in Medium and Low consequence areas).

The ISM detailed PG&E's original CPI program in ISM Report 4, with the initial purpose to leverage the new drone inspections as a means of re-evaluating whether any of the backlogged 118,000 pole tag notifications in HTFD in 2023 (created from ground inspections) could be canceled as a result of viewing the pole from an aerial perspective. If a CPI inspection finds that a pole does not require a repair/replace tag, then it must receive an intrusive test to determine the pole's remaining strength (unless a prior pole test and treat inspection had been done within the prior 2 years). For its 2024 program, PG&E estimated conducting 60,000 CPI inspections, with approximately 15,000 intrusive tests expected.

With the enhanced CPI program, PG&E identified a select set of 76 triggering tag conditions correlated with high asset failure rank, where, if an open tag contained any of these conditions, the tag would be eligible for CPI. PG&E noted that once a tag receives an enhanced CPI, all noted conditions on the tag (not just those CPI triggering conditions) that can be reassessed are evaluated, and the aerial portion of CPI is identical to an aerial WMP inspection.

The 2024 CPI workplan of approximately 60,000 structures was created as a blend, starting with the 2024 tag workplan which included the 2024 mega-bundle circuits (detailed later in this ISM Report 5), incorporating 2023 CPI work not previously completed, then covering all of the Extreme, Severe and High consequence eligible tags, and approximately 50% of the

Medium consequence tags. PG&E indicated that the CPI workplan for 2025 has not been finalized, although approximately the same number of CPI inspections are expected.

Through August 10, 2024, PG&E completed approximately 34,000 CPI aerial inspections for the year, completed approximately 11,000 CPI intrusive inspections, and canceled approximately 1,900 pole tags. In addition to the cancellations, the CPI program also led to PG&E escalating the priority of 1,420 pole tags (49 "A Tags", 94 "X Tags", and 1,277 "B Tags").

During the current ISM reporting period, PG&E reiterated to the ISM that the enhanced CPI program would only be replacing the FSR program for its distribution assets, and that PG&E would continue to perform FSRs on past due transmission notifications with time dependent conditions. Since transmission lines continue to use aerial and ground inspections for multiple vantage points to identify conditions, PG&E indicated that it does not need to rely on a separate enhanced aerial CPI equivalent program. During the current ISM reporting period, the ISM reviewed PG&E documentation that indicated PG&E currently performs approximately 10,000 FSR reviews on its transmission system each year, where tags exist for assets not scheduled for inspection in that year. Escalation rates from transmission FSR reviews range from 1% to 4%, and the transmission Centralized Inspection Review Team (CIRT) reviews the FSR results prior to making any changes. PG&E noted that performing an FSR does not extend the notification compliance due date, and if tags are upgraded in priority, repairs must be undertaken in accordance with the accelerated timelines of the new priorities.

ISM Field Observations

Distribution Field Inspections

Consistent with previous ISM reporting periods, during the current ISM reporting period the ISM conducted field observations on PG&E's inspections, particularly focusing on HFTD and areas with increased ignitions, outages, and open notifications. A significant distinction in this cycle of inspections is PG&E's use of aerial methods, primarily through drone surveillance. In contrast, the ISM conducted ground-based inspections and supplemented them with aerial observations using drone photography from PG&E. This two-pronged approach enabled the ISM to provide observations from both perspectives, enhancing the detection of issues that might be missed by one method alone.

The ISM submitted observations from its inspections which PG&E's inspectors did not identify to PG&E. The ISM noted a reduction in the number of observations submitted to PG&E in comparison to previous ISM reporting periods. For example, year-to-date nearly 3,000 structures were ground inspected using PG&E's 2024 D_x Job Aid where issues not previously identified by PG&E was less than 5% compared to approximately 5,000 structures inspected in 2023 where issues not previously identified by PG&E was approximately 20%.

Ground-based inspections have revealed that some hazards are less visible in drone photography depending on the perspective of the photos taken, particularly, exposed grounds and loose hardware, as shown in Figure 6. In some cases, the perspective of the drone photos does not provide a good view of structural damage. Accordingly, a portion of the decrease in the percentage of issues not previously identified by PG&E likely stems from the limitations of aerial perspectives in detecting ground-level issues. To address these missed photo perspectives, PG&E discussed the possibility of including additional criteria in the "required shot sheet" to capture multiple perspectives in aerial photos. Alternatively, in some cases, the aerial inspections found conditions which would not have been visible from the ground. The ISM will continue to monitor the utilization of aerial inspections.

Figure 6: Left: Photo taken by the ISM of loose hardware; Right: Drone photo of the loose hardware identified in the left photo.

Pole Condition Assessment

The PG&E 2024 D_x Job Aid provides specific conditions for identifying a pole condition which would result in issuing a repair tag. In addition to identifying those conditions, the D_x Job Aid also provides the inspectors with some considerations for elevating the priority of the repair tag depending on the condition of the pole and exposure. During the current ISM reporting period, approximately 525 poles were identified that had sufficient damage to justify the issuance of a repair tag. Based on a review of the PG&E inspections of these poles, PG&E issued repair tags on 483 of the 525 assets. In addition, the ISM identified 6 poles while in the field that PG&E previously identified as a lower priority E tags that the ISM submitted to PG&E to consider reevaluation of the repair priority.

Post field inspection the ISM performed a comparative review of drone and ground-level photos related to these 525 poles. During the ISM's review, the ISM identified several instances of structural damage, such as daylight visible through deteriorated poles, that were not identified via drone images for the same poles as seen in Figure 7 below. To address vantage point misalignments, PG&E discussed the possibility of including additional criteria in the "required shot sheet" to capture multiple perspectives in aerial photos. The ISM will continue to monitor the utilization of aerial inspections.

Figure 7: Left: ISM captured photo from the field; Right: PG&E Drone captured photo

E-Notification Review

During the current ISM reporting period, the ISM performed a targeted review of poles that PG&E had identified with E-tags. To assess whether PG&E's tag assignments were categorized consistent with the PG&E D_x Job Aid, the ISM conducted inspections using PG&E's drone photos, specifically evaluating whether any of the poles should be elevated to a higher-priority tag, such as a B tag, which requires more urgent maintenance using PG&E's D_x Job Aid.

A total of 160 poles marked with at least one E tag were reviewed as part of this analysis. After an examination of the drone photos, the ISM determined that none of poles reviewed exhibited elevated issues that warranted an elevation to a higher-priority tag, such as a B tag. The ISM noted a wide variation among the subset of E tags that were identified and several that need to be repaired within their specified due dates. The ISM will continue to monitor PG&E's tag priority level.

CPI Tag Cancellations

As part of its ongoing monitoring, the ISM conducted an analysis of the approximately 1,900 CPI cancelled pole tags that were described earlier in this ISM Report 5. During the current ISM reporting period, the ISM reviewed a sample of 40 poles were flagged by CPI for cancellation. Of the 40 poles reviewed; 2 poles were flagged with potential issues by the ISM's ground inspection teams due to structural issues including splitting around the pole hardware shown in Figure 8.[11] While reviewing the aerial inspection, which is what PG&E uses in the CPI process, the ISM noted that these poles may not have captured the side or angle of the pole where the potential issue is visible. Of note, PG&E made the recommendation to cancel the

[11] Second pole submitted for additional review (not shown in figure below) displayed a similar condition with splitting around the pole hardware.

Pole/Replace Notification due to existing installed anti-split bolt and through bolt mitigating any further splitting along with a PASS from Pole Test & Treat intrusive test resulting in 100% pole strength.

Figure 8: Left: ISM ground photo taken showing hardware (blue arrow) through split (red arrow) in pole; Middle: PG&E Drone Photo from opposite side of pole. Red arrow shows location of the split on the opposite side of pole. Right: PG&E Drone photo showing top view of pole. The red arrow shows the location of the split. PG&E did not have an aerial photo of the side of the pole which showed the split in the ISM photo.

Of the 38 other poles the ISM examined, the ISM's inspections of these canceled poles did not identify significant structural damage from the ground. Figure 9 show some examples of poles cancelled under the CPI program.

Figure 9: Distribution poles cancelled under the CPI Program

Maintenance

During the current ISM reporting period, the ISM held general discussions with PG&E regarding bundling different priority tags and maintenance items. Through bundling, PG&E's intent is to reduce unit costs and increase repair tag efficiency as PG&E reduces its backlog of maintenance repair tags. Information on the growth of PG&E's distribution maintenance tag backlog, and its risk-informed WMP commitments to clear its tag was provided in ISM Report 4. PG&E states that the tag backlog within HFTD locations will be within compliance by 2029 using a risk-based approach per WMP requirements. Below is an overview of PG&E's bundling programs for its transmission and distribution maintenance tags.

Transmission Bundling:

PG&E bundles Transmission tags during PG&E's annual planning process. PG&E uses a SQL-based database for work allocations, which allows for visibility into the annual plan and can bundle Tag ID's within the database. For Q3 2024, PG&E is developing a visual version of the database that will be map-based, similar to the distribution tool already in use.

For the last two years, PG&E utilized the bundling program. PG&E's asset strategy group assigns maintenance tags based on risk ranking. Transmission maintenance work in HFTD and GO 95 related areas is planned annually to provide time for CAISO's 60 days prior approval for line outage clearances, and to support the completion of all work on time. Bundling efforts have been very effective under these constraints. For example, PG&E recently completed maintenance on the circuit Lakeville No. 1 where several poles were replaced. As part of the bundling process, CAISO was notified in advance of 60-days, Customer Service coordinated with customers (door knocking), a daily schedule was developed, and dependency groups were kept informed.

Distribution Bundling

In 2024, PG&E initiated a "Mega Bundle" program, aimed at bundling all known maintenance work on an entire circuit to improve efficiency and resource management. This includes addressing E and F tags, unless constrained by other factors. PG&E treats Mega Bundles as large-scale projects, where thousands of tags may be involved, and manages Mega Bundles through a Request for Proposal (RFP) process to secure cost-effective contractor services. PG&E indicated that the process helps optimize pricing and minimize the impact on PG&E staffing resources. PG&E identified 20 circuits for Mega Bundles projects in 2024, with several already underway.

During a site visit in Auburn, CA, the ISM observed a Mega Bundle project in progress. Three contractor crews were simultaneously replacing poles and hardware and coordinating customer outages. The site visit provided insight into the overall efficiency of the program, including improved crew productivity, enhanced safety awareness, and streamlined permitting and inspection processes. Additionally, the crews worked closely with PG&E personnel, allowing for efficient staging of materials and quick response to hazards.

Mega Bundles are initially selected based on Risk Spend Efficiency analyses. The program began with 13 circuits, with an additional 7 circuits added by operations, bringing the total to 20 circuits. While the intent is to address all open tags in a Mega Bundle, budget constraints have led to some deferrals, including a recent project where 1,700 pole replacements were postponed.

In addition to Mega Bundles, PG&E utilizes "Operational Bundles," which focuses on bundling tags within specific isolation zones to limit planned outages. These projects, typically managed by local crews as part of annual maintenance, do not require the RFP process and PG&E funds and PG&E executes these projects with employee or contractor crews.

PG&E developed a visual tool to track and manage all bundling programs. This tool allows teams to visualize funded jobs by category and location, helping to coordinate efforts across circuits. In cases where unfunded tags are identified alongside funded projects, teams can propose that the unfunded tags be included through an escalation process, although budget limitations have made it difficult to address unfunded work in the current year.

TRANSMISSION INFRASTRUCTURE

In 2024, PG&E revised its transmission contractor inspector training to improve inspection accuracy by incorporating QA/QC feedback. The training introduced new camera equipment to enhance photo documentation and included plans to integrate Job Aids with inspection checklists on iPads by 2025. PG&E's transmission inspections are undergoing a 24-month pilot program aimed at refining inspection procedures. These observations are detailed in the following sections.

Transmission Contractor Inspector Training

PG&E continues to enhance its transmission contractor inspector training with a strong emphasis on safety. The current contractor workforce is made up of IBEW-qualified journeymen linemen involved in PG&E's transmission inspections for the past three years as part of a contract cycle.

In 2024, PG&E's training focused on enhancing areas of past underperformance, such as missed critical issues, improper photo documentation, and insufficient corrective actions. However, this training did not include a formal examination to evaluate inspectors' knowledge. PG&E expects familiarity with the T_x Job Aids, which guide the inspection process, to be self-taught by the inspectors. For 2025, PG&E plans to link the T_x Job Aids directly to the inspection checklists on the inspectors' iPads. This integration will undergo a trial period and be incorporated into future training sessions.

The training incorporated insights from PG&E's QA/QC reviews, with a particular focus on reducing critical misses. As background, all inspections are desktop reviewed within 7 to 14 days by QC. In 2023, 36,750 transmission inspections were reviewed, with 301 critical misses identified, resulting in a 99.19% pass rate. Training sessions emphasized common issues, such as broken bond wires, connectors against insulators, and loose guy wires, with the goal of further improving the pass rate and reducing inspection corrections.

Additionally, inspectors were trained on the use of new Nikon cameras, provided by PG&E, to ensure quality inspection photos. This equipment is expected to improve photo clarity and support the identification of issues more effectively.

Transmission Inspections

PG&E divides Transmission inspections into three programs: visual climbing, footings & structural, and unmanned aerial systems (UAS or drones). PG&E is revising its visual climbing and footings & structural programs and will evaluate them over a 24-month pilot period.

- Visual Climbing Inspections: This program focuses on 500kV transmission lines, where inspectors physically climb the structures to visually detect defects.
- Footings & Structural Inspections: This program includes both engineering assessments and corrosion evaluations. The engineering assessment covers the structural integrity of transmission towers, soil conditions, and environmental factors, while the corrosion evaluation focuses on below-grade inspections for towers without concrete footings. A new structural rating system will help guide maintenance activities to issues that need immediate remediation.
- UAS Inspections: These inspections are conducted by a two-person team, with a pilot flying the drone and an asset inspector operating the high-definition camera to perform visual assessments.

ISM Observations and Training Review

On March 6, 2024, the ISM observed PG&E's transmission ground inspector training in San Ramon. Approximately 50 IBEW-qualified linemen attended the training. The first day covered environmental, personal, and roadway safety, while the second day focused on inspection checklists and Job Aids. On the third day, the emphasis was on proper camera use, missed infractions, and field review practices. Inspectors also received training on inputting safety-related threats, such as security concerns and dogs, into the Inspect app.

Key topics discussed during the training included "Compelling Abnormal Conditions" (CAC), Centralized Inspection Review Team (CIRT) protocols, line corrective actions (LC) in HFTDs, Field Damage Action (FDA) procedures, and the use of Job Aids. The importance of QA/QC processes, record-keeping, and desktop reviews was highlighted. The training also covered proper photo angles and quality expectations, with the same inspector required to reassess the asset if a follow-up inspection was necessary.

Although no formal assessments were given to trainees, field observations and reviews were conducted. The training placed significant emphasis on safety and QA/QC processes, but less time was dedicated to standards and Job Aids.

VEGETATION MANAGEMENT

PG&E has implemented a number of programs designed to inspect, trim, remove, and manage trees and vegetation in its rights-of-way ("ROW") and near its facilities and infrastructure. In ISM Previous Reports, the ISM reported on changes and updates in PG&E's Vegetation Management ("VM") program(s). In the Q1 2024 ISM Report, the ISM provided observations on three programs that succeeded PG&E's Enhanced Vegetation Management ("EVM") Program: Vegetation Management for Operational Mitigation ("VMOM"), Focused Tree Inspections ("FTI"), and Tree Removal Inventory ("TRI"). During the current ISM reporting period, the "Routine" VM program, a fundamental component to PG&E's overall VM program, continued to be a focus for the ISM, as well as continuing to monitor and report on the VMOM, FTI and TRI programs.

During the current ISM reporting period, the ISM performed targeted VM field assessments, deployed field personnel to review impacts associated with the February 2024 atmospheric river events, conducted field interviews of PG&E and contractor personnel, and observed PG&E programs related to "Tree Connects." The ISM's observations are discussed below.

Vegetation Management (VM) Program Descriptions and Updates

During this reporting period, the ISM reviewed PG&E's key programs related to VM: routine, VMOM, TRI, and FTI. The following provides a summary of the ISM's observations.

Routine

"Routine" vegetation management is one component of PG&E's overall VM Program. Per PG&E's Distribution Vegetation Management Procedures (DVMP) Utility Standard: TD-7102, the Routine VM activities include an annual or Routine Patrol and a Second Patrol[12] that occur based on two annual utility arboriculture cycles: an Inspection Cycle and a Work Cycle.

PG&E's VM crews are expected to perform vegetation work activities and prescriptions[13] to ensure compliance with regulatory requirements and PG&E VM procedures and standards. Per

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[12] The purpose of the Second Patrol is similar to the Routine Patrol - perform scheduled inspections on all overhead distribution facilities to maintain minimum distance requirements between vegetation and conductors in accordance with regulatory requirements and PG&E procedures. The Second Patrol occurs at approximately six months offset from the Routine Patrol on distribution facilities in HFTD and HFRA.

[13] Prescriptions refer to a unique plan for work on an individual property and typically describes in detail the trees to be pruned, removed, treated, etc., and are created by inspectors for each property/site.

ISM discussions with PG&E VM leadership, PG&E stated it intends to complete work associated with dead and dying trees within 180 days for HFTD areas and within 365 days for non-HFTD areas. PG&E has referenced industry Best Management Practices ("BMPs") in its procedures that include the American National Standards Institute ("ANSI") A300 standards,[14] and Wood Management standards.[15]

Figure 10: Left: Inconsistent brush prescriptions; Middle: Topping brush in Right-of-Way; Right: Apparently health tree prescribed for removal

However, as noted in ISM Previous Reports, PG&E's VM Routine practices are not always consistent with ANSI A300 and BMPs. Similar observations were made during the current ISM reporting period as seen in Figure 10 above. During ISM Routine field assessments, the ISM observed brush being inconsistently prescribed for removal in utility ROWs, brush with similar characteristics and within the same span were not always prescribed, and certain brush was topped rather than removed. PG&E's VM system of record did not contain notes or indications of other constraints that would cause a deviation from BMPs. Additionally, the ISM observed instances where healthy black oaks were prescribed for removal associated with a "Reactive" VMOM incident. PG&E stated that species, tree conditions, and tree attributes are considerations to target during "Proactive and Reactive" VMOM.

The ISM will continue to monitor and review PG&E's routine VM activities and the impacts of future changes to relevant procedures.

Vegetation Management for Operational Mitigation (VMOM)

As reported in ISM Previous Reports, VMOM is one of the three replacement programs succeeding PG&E 's EVM program. PG&E created VMOM to help reduce outages and potential

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[14] ANSI A300 standards present performance standards for the care and maintenance of trees, shrubs, and other woody plants, and are intended as guides for federal, state, municipal and private authorities including property owners, property managers, and utilities in the drafting of their maintenance specifications. Integrated VM ("IVM") is a component to ANSI A300.

[15] PG&E Wood Management Standards are published in Best Management Practices (TD 7102P 01 JA01) and Wood Management (TD 7102P 26).

ignitions based on historic vegetation outages on EPSS-enabled circuits. VMOM is comprised of two key components: Proactive and Reactive. The VMOM "Proactive Project" patrols the entire Circuit Protection Zone (CPZ) identified by the Vegetation Assets Strategy and Analytics (VASA) team. Proactive projects address historic vegetation-caused outages and are determined by the tree failure history for the circuit.

PG&E indicated that "reactive" measures will be implemented within the VMOM program to evaluate circuits post-EPSS outage incidents. In such instances, an inspector will examine the circuit for at least 5 spans in each direction from the point of ignition or outage. PG&E's VM leadership notes that not all post-inspections are conducted by an ISA Certified Arborist or an ISA TRAQ credentialed arborist. These inspections and investigations may be performed by personnel with "arboriculture" or related experience.

The ISM observed inconsistencies with prescribed and completed tree work within the system of record. As shown on the left in Figure 11, observations of limb wood, trunks, and stumps from the prescribed and removed trees under VMOM program appeared to be unwarranted removals when compared to trees in the surrounding vicinity of similar health, vigor, and vitality. Further, as shown on the right in Figure 11, the ISM observed vegetation points lacking consideration for degree of lean and deflection potential to the strike target, which is a documented consideration included in the PG&E Vegetation Management Distribution Inspection Procedure (VMDIP) protocol when making assessments during the inspection process.

Figure 11: Left: Black oak VMOM removal with similar trees in vicinity that were not removed. PG&E conductor is across the street; Right: Gray pine in the same span as VMOM removals leaning towards the line on the right side of photo that was not prescribed for removal.

During field assessments, the ISM observed trees that were prescribed and removed due to "fall-in risk" where the system of record did not denote the tree condition as dead or dying, so the ISM is unsure why these trees were removed. As depicted in Figure 12 below, the ISM observed inconsistent VMOM and Routine prescriptions within the same span.

For example, the ISM observed two trees marked for removal under VMOM program and approximately fifteen trees within the same span exhibiting similar health, vigor, and vitality were not marked for removal, but were pruned under the Routine program. The system of record did not contain any noted constraints for this location implying inconsistency in the method of assessment for VMOM or Routine within spans and parcels.

Figure 12: All trees in figure are in located in the same span. Left: VMOM trees marked for removal; Right: Gray pine not marked for removal. The ISM was unable to ascertain why the trees on the left were marked for removal while the tree on the right was not.

The ISM will continue to monitor and review the evolution of PG&E's VMOM activities and the impacts of future changes to relevant procedures.

Tree Removal Inventory (TRI)

As reported in ISM Previous Reports, the TRI program focuses on trees which were previously assessed for EVM using PG&E's Tree Assessment Tool (TAT) or during EVM inspections prior to the use of TAT. Trees within the TRI inventory that have mitigation status of "other than Abate" will be reassessed by a VMI. If the VMI does not believe that the tree is likely to impact the facilities, then the tree must be inspected by an ISA Tree Risk Assessment Qualification (TRAQ) VMI. PG&E's VM leadership stated that under the TRI program, any tree previously assessed as "TAT Abate" will be removed without reassessment if the overhead conductor is still present.

During the current ISM reporting period, PG&E advised the ISM that PG&E is conducting a limited "pilot" re-assessment project on TRI trees with the status of "Abate". The re-assessment is intended to confirm the accuracy of the TAT and introduce changes to correct the mitigation prescriptions. The pilot project began on June 28, 2024. An ISA Certified Arborist with the

TRAQ credential is currently reassessing trees listed with a "TAT Abate" or "other" result.

The ISM performed observations on a sampling of random TRI trees during its field inspection activities. As shown in Table 4, the ISM's TRAQ credentialed arborists' independent assessments aligned with the original TAT recommendations when the recommendation was "other than Abate." However, the ISM observed that the reasons for TAT recommendations of "Abate" were not readily apparent based on Level 2 inspections, and that such trees may require additional assessment to confirm the Abate recommendations.

Table 4: ISM TRI tree observations during the current reporting period.

ISM Observed Tree Condition(s)	TAT Recommendation		ISM Observation	
	Other than Abate	Abate	Confirmed TAT Recommendation*	Not able to confirm TAT Recommendation **
Not Strikable (27)	0	27	0	27
Located Under Conductor (11)	5	6	5	6
Leaning Away from Infrastructure (7)	0	7	0	7
Mitigated by Pruning	3	2	3	2
No Work Required (strikable, not Hazard Tree)	0	9	0	9
Totals	**8**	**51**	**8**	**51**

**All "other than Abate" TAT recommendations were confirmed*
*** None of the Abate TAT recommendations were confirmed.*

Based on the trees inspected by the ISM during the current ISM reporting period compared to the TAT results from the EVM program, the TAT system led to a prescription to "abate" more than the ISM's inspections were able to confirm. The ISM will continue to monitor the TRI program and report on the results of the new pilot project.

Focused Tree Inspections (FTI)

The FTI program prioritizes vegetation management efforts to address miles based on areas of concern, particularly those miles associated with increased outages caused by vegetation or specific tree species. The FTI program established an inspection target of 1,500 circuit miles for completion in 2024. PG&E's VM leadership indicated that during these inspections, Level 2[16] assessments are performed on any tree that could strike PG&E electric facilities (excluding

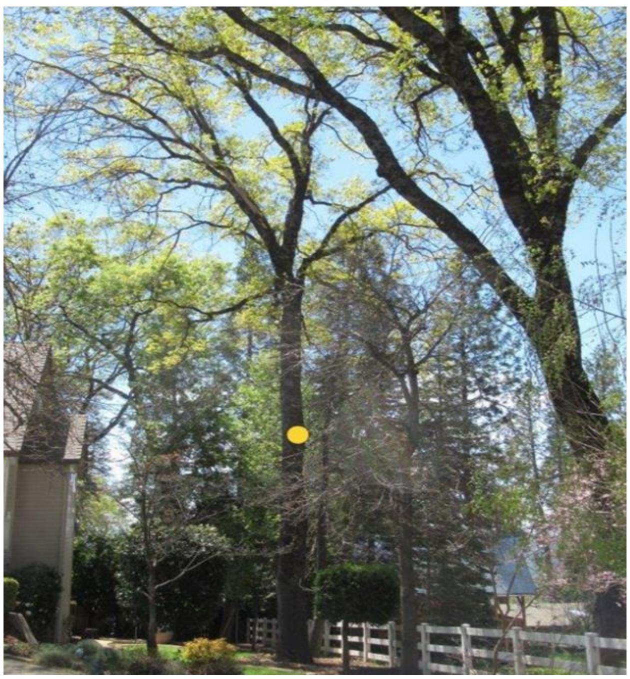
[16] There are 3 levels of inspection associated with ISA TRAQ tree risk assessments. A Level 1 assessment is a "Limited Visual Assessment" (one-sided). A Level 2 assessment is a "Basic Assessment" 360 degrees around the tree and typically utilizes hand tools such as binoculars, magnifying glass, mallet, and or probes. A Level 2 Assessment includes a detailed visual assessment from the base to the crown of the tree. A Level 3 Assessment is an "Advanced Assessment" where specialized equipment, data collection, and analysis and/or expertise is required.

service drops). The ISA TRAQ credential is a prerequisite for personnel to qualify for the FTI and VMI role.

Vegetation Management Inspectors (VMIs) began utilization of the ISA TRAQ Form[17] in its paper format and electronically uploaded. PG&E digitalized the ISA TRAQ Form; however, PG&E suspended use of the electronic form pending updates within OneVM to accommodate both "prescribed" and "inventoried" trees.

As background, within the FTI Program, a "prescribed" tree requires mitigation, and any tree with strike potential is "inventoried" as a Vegetation Point (VP) in the system of record. Strike trees include trees that lean away from the conductor if the height meets the criteria to strike or can be deflected from strike potential.

The ISM observed inconsistencies and discrepancies with prescribed and inventoried trees contained in the system of record. These inconsistencies included 1) prescriptions for the removal of healthy trees, 2) trees inventoried and prescribed that would be deflected from striking PG&E electric facilities, if failure occurred, and 3) trees leaning away from PG&E electric facilities.



[17] The TRAQ Form is a tool for arborists to record and categorize information while performing a basic tree risk assessment using methodology outlined in ISA's Best Management Practices. (https://wwv.isa-arbor.com/education/onlineresources/basictreeriskassessmentform).

Figure 13: Upper Left: Healthy black oak marked as fall-in risk with one dead limb present at time of observation (~50ft from conductor, whole tree failure unlikely); Upper Right: Healthy incense cedar marked as fall-in risk; Lower Left: Healthy tree leaning away from conductor; Right: 35ft tree located 40ft from conductor marked as fall-in risk.

The ISM will continue to monitor and review the evolution of PG&E's FTI activities and the impacts of future changes to relevant procedures.

ISM VM Targeted Field Inspections & Interviews

During the current ISM reporting period, the ISM continued performing targeted VM field assessments in areas experiencing the highest number of vegetation caused interruptions and the highest number of ignitions (based on ten years of data provided by PG&E). The ISM's targeted assessments included the FTI and VMOM programs, transmission inspections, and the February 2024 Atmospheric River Event Interruptions. These field inspections build on the observations presented in ISM Report 4, as depicted in the following table.

Table 5: ISM Targeted VM Inspection Summary of Data Collection

Attribute	ISM Report 4	Current ISM Reporting Period	Totals
Number of Observations (Radial Clearance or Hazard Tree)	4	44	48
Wood Management non-compliant (#of spans)	19	4	23
ANSI-A300/BMP non-compliant (# of spans)	122	357	479
Number of Level 1 Assessments	1,890	13,222	15,112
Number of Spans Inspected	136	791	927
Percentage of spans with ANSI-A300/BMP (non-compliant conditions)	90%	45%	52%

During field observations related to the FTI and VMOM Programs, the ISM was periodically approached by PG&E customers with questions, concerns, and comments. PG&E acknowledges that the various programs and inspection processes create numerous touchpoints with customers in the field, and that customer communication and outreach has been challenging. A common theme experienced by PG&E's field staff is customer dissatisfaction with the number of property incursions and lack of communication. PG&E recently created a customer coordination position to help facilitate customer outreach and communicate VM program activities.

Atmospheric River Event – February 2024

The February 2024 "Atmospheric River Event" impacted customers in Placer and El Dorado counites. Using data provided by PG&E, the ISM performed observations and assessments at various locations impacted by the event to confirm if known or existing vegetation points were the cause of service interruptions during the event period. The following table summarizes the number of points and findings associated with the observations and assessments conducted.

Table 6: ISM findings from after an Atmospheric River Event

# of Vegetation Points (VP)	VP in System of Record YES	VP in System of Record NO	Whole Tree Failure	Branch/Trunk Failure
9	1	8	6	3

As shown in the table above, one tree reviewed by the ISM that had an existing vegetation point failed during the event. PG&E previously prescribed the dead tree for removal on October 5, 2023. It was a partial tree failure showing signs of bark slipping which suggests that the tree had been dead for an extended period of time prior to the prescription. The tree failed prior to work execution. During the field assessments, the ISM observed tree-caused interruptions resulting from saturated soils, wind for sustained periods, and heavy rain. The event's "abnormal" conditions likely contributed to an increased tree failure potential.

During field observations of the "post-event", the ISM observed prescriptions for the removal of healthy black oaks proactively identified by PG&E after the event. The ISM also observed four dead ponderosa pine Hazard Trees with the potential to strike multiple line segments. These trees were not identified during post storm investigation conducted by PG&E.

Figure 14: Left: Dead ponderosa pine not identified as a hazard tree in post storm investigation; Right: Wood management deviations from ANSI BMPs

The mortality of the dead ponderosa pines was not likely due to the event, based on the advanced stage of bark slippage and needle casting shown on the left of Figure 14. Related ISM observations of logs and stumps exhibited signs of being dead for an extended period based on the bark slippage and the discoloration of wood. Additionally, the ISM observed wood management deviations from PG&E's procedures and ANSI A300 BMPs shown on the right of Figure 14, where logs were cut and placed in roadside drainage areas.

Vegetation Management – PG&E VM In-Field Interviews

During the current ISM reporting period, the ISM conducted interviews with PG&E's field VM staff located in two divisions. The interviews were related to the Routine VM Program, the role of Vegetation Operations Inspectors ("VOI"), the FTI Program, and VM Quality Assurance/Quality Control. Personnel interviewed included Directors, Managers, Supervisors, VOIs, Senior Vegetation Management Inspectors (SVMI), Vegetation Management inspectors (VMI), tree crew vendors, and the QAVM-P (Distribution audit process) teams.

The ISM's interviews occurred during ongoing work activities. The following provides a summary of the ISM's interviews and related observations.

Routine VM Program Interviews

The ISM interviewed VMIs in two divisions regarding procedures, standards, and training. The topics discussed included customer notifications and system of records, and the use of arboriculture tools. The ISM also interviewed VMIs performing Second Patrols.

Routine – Customer Notifications

The ISM discussed the customer contact and notification process to perform tree-related work.

As background, PG&E procedures[18] require at least three attempts to notify customers regarding prescribed tree work on their property - describing the work to be performed. Acceptable methods of contact include direct, phone, email, door hanger, and letters.

In the first division, PG&E indicated that strong easement language exists in customer agreements, which is utilized should customer interference occur. One contracted VMI indicated that the process for customer contact has changed:

- PG&E no longer asks for permission for VM work, but rather informs the customer as a courtesy notice.
- The VMI marks trees with paint and then notifies the customer of identified work by either leaving a door card, attempting a phone call, or speaking in-person to the customer.

The VMI reported that only one attempt to contact the customer is performed. This appears inconsistent with the PG&E customer notification procedures and associated training (PG&E's 2024 Execution Kick Off and Training), as more fully discussed in ISM Report 4.

In the second division, the following process was reportedly used for customer contact:

- Three attempts are made to contact the customer (in person/door card/voicemail) prior to the VM prescription.
- Pictures are taken of the door card with date and time.
- Documentation from voicemails, in-person contact, and other contact is documented in the system of record.
- Automated telephone calls ("Robo calls") and texts are initiated informing customers of upcoming VM work activities prior to commencing work.

Interference letters are sent to educate customers on PG&E's VM activities as well as to promote the "Right Tree Right Place" program.[19] PG&E management stated that the objective of the newly implemented "Right Tree Right Place" program is customer communication and community engagement.

Since the time that the ISM informed PG&E regarding customer notification discrepancies, PG&E reported that the VMIs have been re-trained to follow established procedures that include at least three customer notification attempts.

Routine – System of Record

The ISM discussed PG&E's use of systems of record with the VMIs. As discussed in detail in previous ISM Reports, PG&E began the transition to OneVM in 2023 with the intention of consolidating all VM programs onto a single platform. The transition is expected to occur over multiple years. The following interview observations were noted.

The transition to OneVM is still in process, and the VMIs stated that multiple systems of record

[18] Vegetation Management Distribution Inspection Procedure (VMDIP) TD-7102P-01.

[19] PG&E's "Right Tree, Right Place" resources provide planting guidelines to ensure that the trees do not interfere with overhead or underground electric or gas lines.

continue to be utilized to accomplish work tasks. For instance, OneVM does not currently provide for EVM prescriptions, therefore Field Maps is referenced. The Priority Tag Tool (PTT) is also on a different system of record. The ISM will monitor the transition to OneVM and will report on its progress in subsequent reports, as appropriate.

Routine – Arboricultural Tools

During field observations and interviews, the ISM noted inconsistencies in the use and application of arboriculture tools. In one case, the VMI measured the diameter but did not use a tool to measure the tree height or the actual distance to the conductor. Those parameters were estimated.

When the ISM inquired as to why measurements are estimated, the VMI responded that their management advises that measuring every tree height and distance to conductor impacts productivity, and that estimating such factors are encouraged.

The ISM reported this observation to PG&E management. PG&E responded that this is inconsistent with VMI training and that VMIs are to utilize proper arboricultural tools and follow the VM protocol. PG&E management stated that they have revisited the expectations with the vendor regarding this issue.

VMI Second Patrol

The ISM interviewed and observed two contracted VMI's conducting Routine "Second Patrol" inspections. As reported in ISM Report 4, the VMI's performing "Second Patrol" activities are not required to be ISA Certified Arborists, and the two VMIs interviewed were not ISA Certified Arborists and had varying levels of experience in VM. During previous ISM reporting periods, PG&E's VM leadership informed the ISM that not all internal VMIs are ISA Certified Arborists, and that obtaining such certification in a timely manner is strongly encouraged.

The ISM inquired if the VMIs utilize OneVM as the system of record. Both VMIs acknowledged that multiple systems of record are required to successfully complete assigned work.

The ISM inquired how secondary voltage is inspected and recorded for work. PG&E's representative indicated that all secondary voltage is patrolled for "strain and abrasion" - excluding service to a single residence. Deflection of the wire is considered "strain." PG&E management noted that disconnection of secondary facilities to conduct tree work by PG&E's tree vendors is the most frequently requested assistance activity.

PG&E management also indicated that "Second Patrols" may be performed with FTI and Routine inspections, simultaneously, to minimize touch points.

PG&E selectively sends an informational letter notifying customers of vegetation conditions, like the Right Tree, Right Place program, that may conflict with PG&E facilities in the future; and encouraging the relocation or removal of said vegetation. PG&E coaches the VMI's on recognizing these conditions to reduce mitigation efforts.

Vegetation Operations Inspectors (VOI) Responsibilities

PG&E created the VOI positions in 2020 as a result of a court settlement with certain counties. The purpose of the VOI position is to ensure safety, quality, and efficiency. The VOI must have at least 5 years of experience in utility line clearance, although some pre-existing VOI personnel with less than 5-years experience have been retained. VOI staffing has grown to one hundred and forty-five PG&E employees throughout the service territory.

VOIs participate in training vendors, safety stand-downs, stop work, and coaching when unsafe actions are observed. The VOIs are expected to promote positive interactions with vendor personnel, and to develop relationships and build trust with tree crews and VMIs.

PG&E reported that a positive safety culture and structure with tree crew personnel, vendor supervision, and VMIs is a critical component to the VOI program. VOIs typically meet crews or VMIs at start up and travel throughout the assigned area from crew to crew. VOIs also assist tree crews and VMIs with customer interactions.

During the current ISM reporting period, the ISM accompanied the VOIs during field observations and tree-crew interactions. As background, PG&E developed a QR code ID badge with Industrial Training Services, a third-party vender (i.e., ITS badge) for tree crew vendor personnel. The ITS badge contains work history, accidents, performance, training, certifications, and other details about the individual crew member, and follows the crew member if hired by a different vendor working on PG&E's systems. PG&E utilizes the ITS badge to aid in matching the certifications, credentials, and knowledge, skills and abilities ("KSA's") to specific VM program projects. Per PG&E leadership, in the future PG&E plans to expand the ITS badge program beyond the tree crew vendor employees to include VMI and SVMIs.

The ISM observed two tree crews working on trees assigned to specific projects. The crews were utilizing aerial lift trucks, performing climbing and rigging, and directing traffic with traffic control personnel.

The ISM and PG&E's VOI team interacted with tree crew leaders that explained the daily job site briefings. Specific attention to job site safety and worker safety were discussed in addition to specific hazards, work procedures, special precautions, and conditions.

FTI Program Interviews

During the current ISM reporting period, the ISM met with PG&E's SVMI and VMI employees performing assessments on the FTI program during VM field interviews. The ISM learned there are multiple contract vendors providing SVMI and VMI support in the second division. The ISM observed field procedures for measuring diameter at breast height (DBH) with a diameter tape. The height of trees and horizontal distance to conductor were measured with a range finder. DBH measurement is important as unit-based pricing is determined by DBH. The FTI program undergoes a 100% QC process.

The SVMI discussed a change in the assessment process for the FTI program whereby tree lean is no longer a parameter to be considered regardless of the direction, degree of lean, or deflection potential. The SVMI reported that tree height is the only determining factor to inventory the tree into the FTI system of record. When the ISM discussed this issue with PG&E's VM management, PG&E reported that both tree height and direction of lean are parameters required by PG&E procedures.[20] The ISM will continue to monitor and observe the FTI program.

QAVM-P Distribution Audit Process

During the current ISM reporting period, the ISM interviewed and accompanied PG&E's VM Quality Assurance (QA) team. The team reported that QA differs from Quality Control (QC) in that QA performs audits on both completed QC work as well as completed execution work. A QA finding is any tree capable of growing into Minimum Distance Requirements (MDR) or "falling into facilities" within thirteen months from VMI date. The QA process uses a statistically validated sampling of all VM programs based on the requirements of PRC 4293. VM QC covers 100% of in-scope locations based on VM QC's business processes. PG&E's QA team reported that a fifty percent threshold is required to list certain findings (i.e., if a tree is fifty percent dead, then it is considered dead), and that "Fall-In" trees are the most prominent findings in the audit process at the time of the field visit, ANSI/BMP compliance is not part of the QA scope due to procedural commitments related to regulatory requirements.

The system of record for QA audits is Field Maps and not OneVM. The QA team is the last to review work completed by VM personnel, and findings could be the result of the VMI and or tree crew, depending on the scope of the audit. QA audits can either be post VMO or post VMI and the Tree Work. The QA accuracy level is reported to be approximately 99 percent.

PG&E's QC Team notes that no changes are made to any prescribed vegetation points made by VMIs for missed or overprescribed trees. Consultation with the VM execution team is the only action taken. QC/QA findings are contained in a Power BI report that is accessible to the VM execution team for mitigation. Quality Management also provides a weekly update to the VM execution team for organizational alignment and consistent tracking.

Tree Connects (Tree Line Trees)

PG&E identified approximately 20,000 existing trees that function as "Tree Connects". "Tree Connects" are considered and tracked as units of electrical infrastructure functioning as a pole, often with multiple attachments and equipment. Tree Connects contain distribution and secondary electrical infrastructure equipment such as insulator attachments for conductors and transformers mentioned under the California Code of Regulations (CCR) Title 14 Section 1258. During the current ISM reporting period, the ISM observed 78 tree connects in approximately 8 miles of primary conductor during one observation site visit.

PG&E advised the ISM that there is no specific program in place to replace "Tree Connects" with a pole. However, eliminating "Tree Connects" during specific system hardening, mega bundling, and undergrounding projects does occur. PG&E estimated that approximately 1,200 tree connects per year will be replaced with poles.

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[20] VM DIP Utility Procedure: TD-7102P-01 references the California Power Line Fire Prevention Guide, 2021 edition by restating: "Trees with more than a slight lean away from utility infrastructure are unlikely to strike the infrastructure, regardless of their weight distribution. Within reasonably foreseeable field conditions, such trees are generally not hazardous to infrastructure. Otherwise, the direction and the amount of lean should be carefully evaluated."

PG&E advised the ISM that tree removal or topping to pole height is performed when the tree is determined to be declining or dead.

PG&E VM Management stated that “Tree Connects” are inspected two times per year pursuant to PRC 4293 and GO 165. PG&E also stated that inspections are conducted as a “Green Tree.” If the tree has been topped to pole height or is otherwise dead, then it will be replaced within one year with a standard pole.

Figure 15: Left: Remaining former tree connect, became a hazard tree; Middle and Right: Hazard tree serving as tree connects

The ISM will continue to conduct observations and collection of data associated with “Tree Connect” construction.

GAS OPERATIONS OBSERVATIONS

The ISM monitors certain safety and risk aspects of PG&E's natural gas operations and infrastructure. As outlined in the scope of the ISM Contract and in consultation with the CPUC, the ISM's gas operations and infrastructure focus in this ISM Report 5 is directed toward: 1) Risk Model Updates, 2) Construction QA/QC, 3) Leak Survey and Leak Management, 4) Construction Close-Out and Records Management, 6) Damage Prevention, 7) Safety Management, 8) Maximum Allowable Operating Pressure Program, 9) In-Line Inspection Program Update, and 10) Gas Asset Data Management.

PG&E TIMP & DIMP RISK MODEL UPDATES

As prescribed by the Pipeline Hazardous Materials Safety Administration (PHMSA), PG&E prepares and runs risk models as part of its Transmission Integrity Management Program, (TIMP) and its Distribution Integrity Management Program (DIMP). These risk models address risk on their respective systems and provide a risk ranking for each pipeline segment in order to inform maintenance and inspection activities, with the goal of improving safety throughout the system. The ISM monitors the TIMP and DIMP risk modeling activities, including reviewing updated risk model results, and tracking changes to the model from year to year. Below is a discussion of activity in the TIMP and DIMP risk modeling efforts during the current ISM Report period.

TIMP Risk Model

PG&E runs its TIMP risk model on an annual basis, updating the risk rankings for each of its transmission pipeline segments. The TIMP risk model calculates a quantitative risk score for each pipeline segment, with risk being defined as the Likelihood of Failure (LoF) multiplied by the Consequence of Failure (CoF), which is calculated for two failure modes, leak and rupture. These risk scores are summed over ten threat categories: 1) External Corrosion, 2) Internal Corrosion, 3) Selective Seam Weld Corrosion, 4) Stress Corrosion Cracking, 5) Third Pary Damage, 6) Manufacturing, 7) Construction, 8) Equipment Failure, 9) Incorrect Operations, and 10) Weather Related & Outside Forces. Each threat category utilizes a unique algorithm to calculate the LoF across each pipeline segment in Ruptures per year. Each year, PG&E updates these calculations with new information, and incorporates any approved changes to the algorithm. Figure 16 below shows the change in total LoF calculated in the TIMP model runs from 2021 to 2023.

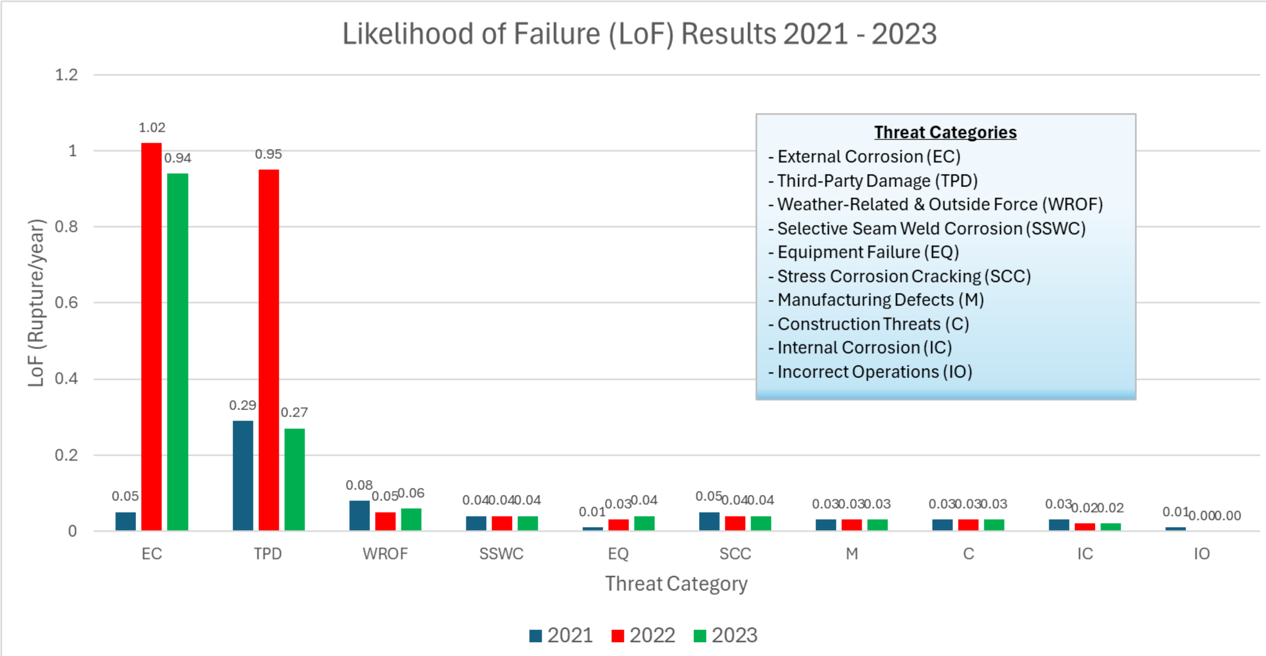

Figure 16: Likelihood of Failure (LoF) Results 2021-2023

In the gas utility industry, it is typical for Third Party Damage (TPD) to result in higher projected risk scores than many of the other threat categories. However, the ISM noted that the External Corrosion (EC) threat was significantly higher than in years past, for example, in 2021 EC LoF was 0.05, in line with many of the other threats, while the 2022 and 2023 EC LoF increased to 1.02 and .94, respectively. The TIMP Risk Model calculates LoF for the EC threat via one of two methods. Where In-Line Inspection (ILI) data for a pipeline segment is available, this data is used to calculate the LoF for that segment. Where ILI data is not present, a probabilistic algorithm is used to predict LoF based on data such as coating, age of installation, material of construction, etc. During the current ISM reporting period, the ISM held interviews with PG&E's EC Steering Committee (SC) to understand the cause of the sustained increase.

PG&E's EC SC indicated that an ILI was run on a segment of pipe, Line 131, in 2016, which showed several flaws, indicating significant external corrosion was present. More than twenty distinct flaws were in this segment of pipe, with several showing significant wall loss. Due to an issue with the ILI's data formatting, this data was not incorporated into PG&E's TIMP Risk Model until 2022. When this data was included in the TIMP Risk Model, including the number and severity of flaws related to EC that were found, it caused the LoF for EC to increase significantly from 2021 to 2022. Upon further investigation, PG&E found that the flaws had been remediated via pipeline repair and/or replacement, so the ILI data incorporated into the TIMP Risk Model needed to be updated with these repairs.

PG&E indicated it remediated the significant flaws in Line 131 via replacement of a portion of this pipeline, and PG&E re-ran the ILI on this segment of pipeline in 2023. When pipeline is replaced and/or when new ILI data becomes available, the inputs to the EC TIMP Risk Model calculations are updated. When the results of the pending ILI become available and are incorporated into the model the EC LoF score will reflect such changes.

The ISM notes that once the ILI results indicated that significant external corrosion was present on Line 131, PG&E took precautions to remediate the segment of pipeline to ensure its safe operation. When the TIMP Risk Model incorporated the ILI results, the risk scores increased significantly, indicating that Line 131 posed a potential safety risk and required action. This suggests that the TIMP Risk Model is sufficiently sensitive to the EC data inputs from ILI inspections. However, questions remain around why the probabilistic LoF calculations used did not rate Line 131 with a higher LoF prior to the ILI data being introduced. The ISM will continue to monitor the LoF calculation results and methodology within the TIMP Risk Model.

DIMP Risk Model

Similar to TIMP, PG&E runs its DIMP Risk Model to update the risk rankings for each of its distribution pipeline segments. However, unlike TIMP, the PHMSA regulations around DIMP are less prescriptive, requiring the risk model to be run at least every five years. PG&E indicated that it typically runs its DIMP Risk Model on an annual basis. The DIMP Risk Model run includes two steps: 1) running the risk algorithm to determine risk rankings and 2) a mitigation analysis. Each of these steps take place every year, with the mitigation analysis using the previous years' risk algorithm results. Therefore, a full cycle takes two years to complete. In 2024, PG&E's DIMP Risk Steering Committee approved a pause in the execution of the risk assessment processes for the 2024 DIMP cycle, indicating that DIMP personnel would be reallocated from the risk assessment execution to other areas of importance. During the current ISM reporting period, the ISM interviewed the DIMP Risk Steering Committee regarding this pause.

PG&E indicated that the pause was to reallocate DIMP personnel to temporarily focus on other work areas which require significant effort. Specifically, these efforts include:

- Developing the tools necessary to create and validate new data sources, including mining and reviewing data from SAP;
- Making significant changes and updates to the DIMP Risk Model; and
- Supporting PG&E's transmission redefinition efforts, including working with the TIMP team to understand the process changes and ensure continued compliance with regulations.

PG&E indicated that the duration of the pause will be one year, with the DIMP Risk Model risk assessment scheduled to resume in 2025. The recommendations from the mitigation analysis performed will stay in place, and the results from the 2023 risk assessment results will be used to inform maintenance and inspection activities, while taking into account any new information based on leak data. This is not the first time a pause in the DIMP execution cycle was enacted. A prior pause was taken in 2021 due to an IT issue with the DIMP Risk Model software. A similar approach was taken in 2021 to what the DIMP Steering Committee is proposing in 2024.

PG&E noted that this pause is not a result of a staffing issue within the DIMP team. The DIMP team has been a stable department, with a long average tenure and little turnover. This pause is due to a variety of required process enhancements, discussed above, that are not expected to be long-term requirements.

The ISM will continue to monitor the DIMP Risk Model activity, including when the risk assessment resumes, as well as following progress on data enhancements, updates to the DIMP Risk Model, and progress in the transmission redefinition effort.

CONSTRUCTION QA/QC

Construction quality is a key component to the safe and effective operation of utility systems, and PG&E provided information to the ISM regarding its Quality Management System and Ongoing Monitoring Programs for natural gas construction projects.

The Construction QA/QC program at PG&E is supported by a dedicated team, including:

- Eight Senior QC Specialists who report to the Construction Quality Verification (QV) Supervisor and are responsible for performing field verifications.
- Twenty-four Gas As-Builts QC personnel who report to two Transmission and Distribution As-Built supervisors.

The following provides an overview and observations of PGE's construction QA/QC program and discusses related site visits witnessed by the ISM.

Overview of PG&E's Quality Management System (QMS)

During interviews with the ISM, PG&E reported that the natural gas Quality Management System (QMS) is a structured framework that outlines the processes, procedures, and responsibilities aimed at achieving quality objectives within the organization. The QMS is intended to help ensure that construction projects comply with established standards and maintain consistent quality. The system is divided into three primary components: Quality at the Source (QATS), Quality Control (QC) and Quality Verification (QV), and Quality Assurance (QA). The following provides a summary of QMS.

Quality at the Source (QATS)

QATS is a Lean Management principle to measure quality at every step of a productive process. PG&E indicated, and the ISM observed, that PG&E adopted and implemented many Lean principles, and the QMS team stated that QATS is focused on the principle of "performing work right the first time." One component of QATS is completion of 90% of "job-complete 'as-built' records reviews" and making real-time corrections before critical tie-in stages. This approach is designed to minimize errors and ensure that the work meets quality standards from the outset. The QATS process is intended to reduce the likelihood of rework.

Quality Control (QC) and Quality Verification (QV)

PG&E indicated to the ISM that PG&E designed QC and QV processes to maintain compliance with PG&E's quality requirements and standards and encourage adherence to procedures during fieldwork. The processes are to be conducted in close to real time actions, allowing for immediate identification and correction of errors. The steps involved in QC and QV include:

- Identifying errors
- Communicating these errors to local leadership
- Explaining the necessary corrections

- Following up on the implementation of corrections

Per PG&E, this approach encourages prompt attention to quality issues to minimize potential impacts on project timelines and overall quality.

Quality Assurance (QA)

The QA process provides oversight and guidance for the continuous improvement of QC methods and controls. It involves field verification, verification of QC protocols, and the identification and communication of errors through established reporting structures. QA is also responsible for developing High Finding Corrective Action Plans (CAPs), when necessary, and conducting process audits, followed by post-audit corrective actions.

Performance and Metrics

Year-to-date, PG&E performed over 12,000 QA/QC checks and reported that a total of four high risk findings related to the construction were identified. This low error rate could suggest a high level of effectiveness in the QA/QC processes. The ISM will continue to monitor the QA/QC program, and report associated trends in future reports.

Ongoing Monitoring

The PG&E QMS team indicated the overall QA/QC program comprises a structured approach, involving QATS, QC/QV, and QA programs, to identify errors, and pursue continuous improvement opportunities. However, PG&E noted it does not employ Acceptable Quality Limit (AQL) sampling methods to determine the quantity of QA activities needed to minimize risks associated with the acceptance of work. AQL is considered QA best practice and provides a practical and effective method for assessing quality by categorizing defects into three levels: critical, major, and minor. As a result, PG&E is currently unable to determine the total number of critical-to-quality tasks performed in the field, thereby limiting their capacity to comprehensively assess the adequacy of the QC program.

During the current ISM reporting period, the ISM accompanied PG&E's QA staff to multiple construction projects related to gas distribution and transmission. The visits spanned four sites, each varying in scope from residential pipe replacements to pipeline relocations. Observations included QA oversight of operational qualifications (OQs), site safety, and project documentation, with any outstanding issues identified and reported by QA staff.

QA Site Visit Observations

Across the four sites, QA staff checked compliance with established PG&E quality and safety standards. During the July 18th site visits, issues were identified related to missing calibration results for boring machinery and difficulties locating plastic casing during excavation. Table 7 and subsequent photographs summarize the ISM's QA observations and outcomes.

Table 7: ISM's QA Site Visit Observations

Date	Project Description	Key Activities by QA Staff	Issues Noted by QA Staff	QA Outcome/ Conclusion
July 18th	Residential Aldyl-A Pipe Replacement using PG&E personnel	Reviewed OQs, project plans, permits, and mechanical joints	Missing calibration results for boring machine	Follow-up through corrective action procedure
July 18th	Steel Distribution Main Plastic Casing Removal	Performed safety assessments, reviewed OQs and site safety documentation	Challenges in locating plastic casing	Logistical challenges managed through exploratory excavations
July 19th	Residential Aldyl-A Gas Pipe Replacement using contractor personnel	Checked OQ, inspected gas lines, reviewed documentation	None	Project proceeding with qualified personnel and appropriate documentation
July 19th	Transmission Pipeline Relocation	Reviewed plans, OQs, pipe design and strength	None	Project focused on technical integrity over slip fault

Figure 17: Excavation with the new 2-inch distribution PE pipe, older Aldyl-A pipe, and other utilities

Figure 18: Excavation by backhoe and vacuum truck to expose the steel pipe and plastic casing

Figure 19: Temporary pipe yard representing hundreds of feet of 10-inch steel pipe for transmission pipeline relocation

LEAK SURVEY AND LEAK MANAGEMENT PROCESS

PG&E developed a Leak Survey and Leak Management process to confirm the safety and reliability of gas gathering, transmission, and distribution pipeline facilities. The process is governed by PG&E's Leak Survey Process and Leak Grading and Response utility procedures, which provide instructions for conducting leak surveys, grading leaks, and responding to detected leaks in accordance with federal and state regulations.

This high-level assessment reviews the existing framework, staffing, ongoing monitoring, and site visit observations.

The Current Process

PG&E's leak survey procedures outline a framework for detecting, grading, and addressing leaks through established guidelines and monitoring protocols. PG&E employs a variety of advanced leak detection technologies, including the Heath DPIR Handheld for sensitive gas detection, the RMLD Handheld for remote methane detection in hard-to-reach areas, the RKI Drone for aerial surveys of large or inaccessible regions, and the Picarro Vehicular system for drive-by leak detection along pipelines. This approach aims to improve the efficiency of identifying and managing leaks while maintaining compliance with safety standards.

Planning and execution cycles—conducted annually, biennially, and triennially—are coordinated by PG&E's analyst group to support compliance workloads and work bundling. Regional directors are involved in managing localized operations so that leak surveys are conducted across different regions in a structured manner.

PG&E employs a risk-based approach to leak management, using an industry-standard grading system (Grade 1, Grade 2, and Grade 3) to prioritize critical leaks for immediate repair, while others are monitored or scheduled based on resource availability. The DIMP integrates pipeline replacement and capital repair efforts, focusing on areas identified as high-risk. Additionally, a dedicated leak survey process owner is responsible for overseeing process improvements and incorporating organizational learning.

Staffing

PG&E employs 100 full-time leak survey technicians, 11 Picarro drivers, and between 60 to 80 contract resources during the peak leak-survey season from March to September. The staffing model integrates both full-time and contract resources to allow for flexibility in managing compliance workload requirements.

PG&E indicated to the ISM that the mix of full-time and contract personnel provides the ability to scale operations as needed - supporting survey completion schedules and compliant response times. PG&E appointed regional directors to its leak survey planning process to support staff allocations across different regions.

To keep pace with evolving leak detection technologies, PG&E indicated it provides ongoing workforce training and equipment upgrades.

Areas for Ongoing Monitoring

PG&E identified several areas for continuous improvement: incomplete leak surveys, accurate mapping, data quality, response and resource coordination, training, and contract labor. As background, incomplete leak surveys due to restricted access to certain facilities (noted as CGI) may pose risks to the thoroughness of inspections and may lead to undetected leaks. Ensuring accurate maps through triennial map plat reviews remains challenging, particularly in rapidly changing urban areas. Efforts like service mapping, aimed at aligning customer data with GIS service maps, help improve accuracy but require ongoing attention to data integration.

PG&E established response targets: 19.5 minutes for initial response and 60 minutes to make leaks safe. However, resource constraints during peak periods can impact performance. While advanced technologies strengthen leak detection, maintaining consistency requires that all field technicians are adequately trained on the latest tools. The reliance on contract workers during busy periods introduces variability, underscoring the need for strong onboarding and training programs.

PG&E indicated continuous improvement efforts that utilize the data collected from leak surveys, response times, and repair outcomes to identify trends, areas of recurrent issues, and opportunities for process improvements. The ISM will continue to monitor PG&E's continuous improvement efforts.

Site Visit Observations - Neighborhood Leak Survey

On July 19th, the ISM conducted a site visit in Fremont, California, to observe PG&E's distribution leak survey activities in a residential neighborhood. This inspection was part of PG&E's compliance program, which mandates regular leak surveys of distribution areas. The current inspection followed a survey conducted in the same area three years prior.

The inspector began by performing a brief Job Site Safety Assessment (JSSA) before proceeding with the leak detection process. Using a Heath DetectoPak DP-IR, a methane detector equipped with a wand probe, the inspector methodically followed the service lines leading to house gas meters. The inspection involved probing near sidewalks, utility covers, and along service lines branching to houses to detect potential leaks.

During the inspection, the inspector identified a Grade 1 leak at a private gas service line junction connected to a gas meter in a fenced backyard. Following PG&E's protocol, the inspector immediately notified the homeowner and contacted the PG&E Gas Service Repair (GSR) team. The inspector remained on-site while the GSR team arrived to address the leak. The ISM team departed the site once the PG&E inspector began the process of remaining at the location for further GSR inspection and repair activities related to the detected Grade 1 leak.

CONSTRUCTION CLOSE-OUT AND RECORDS MANAGEMENT

PG&E's Construction Close-Out and Gas Records Management is structured around three main utility procedures:

- The As-Built Procedures and Mapping Procedures for Distribution and Transmission govern the process of documenting and mapping constructed assets and activities in PG&E's geographic information system (GIS).
- The Operational Change Notification (OCN) procedure manages the communication and documentation of operational changes within PG&E's systems, particularly updates in SAP, the company's enterprise resource planning software.

The mapping process aims to incorporate as-built records to reflect the physical state of the gas distribution and transmission systems. The process cycle is managed with specific goals for timely updates in the GIS platform, with the performance metrics as follows:

Transmission Mapping:

- Goal: 270 days
- Actual: 222 days

Distribution Mapping:

- Goal: 76 days
- Actual: 44 days

These metrics suggest that PG&E's actual cycle times are shorter than the targeted durations for both transmission and distribution mapping.

The OCN process facilitates the documentation of operational changes in SAP, triggering compliance-related workflows. The procedure includes an Update Cycle where changes are entered into SAP within 1 day of completion, and a Compliance Workflow where SAP automatically initiates compliance-related tasks, upon entry, to address the changes.

PG&E established a review process for non-compliance incidents that starts with Process Manager Oversight: The process manager reviews each non-compliance self-report to identify if an issue is related to faulty records or extended process cycle times. Weekly reviews are conducted with functional leaders, and a more comprehensive review is held monthly with the compliance committee. PG&E reported that the majority of non-compliance issues identified are attributed to legacy records or processes.

PG&E stated that in order to address and mitigate non-compliance issues and to continuously improve performance, each process and function within PG&E's Construction Close-Out and Gas Records Management framework, it is engaged in weekly huddles and the process is further supported by a Tactical Improvement Plan (TIP). These TIPs are designed to provide targeted interventions and enhancements to improve process performance and compliance outcomes.

The ISM will continue to review PG&E's Construction Close-Out and Gas Records Management processes and will report on process changes or deviations from plan, as appropriate.

DAMAGE PREVENTION PROGRAM

PG&E's Damage Prevention Program aims to safeguard underground utilities and ensure infrastructure reliability. Key components include "Locate and Mark" and "Watch and Protect," supported by public awareness initiatives such as 811 workshops. The ISM reviewed PG&E's damage prevention ecosystem, current performance, and areas of ongoing monitoring.

Damage Prevention Ecosystem and Stakeholders

The damage prevention ecosystem is a network of interconnected stakeholders, each playing a role in the safe and effective protection of underground utilities. The success of this ecosystem depends on the collaboration and communication among the following key participants:

- 811 Center: Coordinates communication between excavators and utility companies for marking underground assets before excavation.
- Facility Owners (PG&E and Others): Respond to 811 requests by marking underground utilities.
- Excavators: Must contact 811 before digging and follow safe practices.
- Locators: Physically mark underground utilities.
- Project Owners and Designers: Ensure precautions are taken during project planning and execution.
- CPUC, Energy Safety's Underground Safety Board, and Common Ground Alliance: Oversee utility compliance, investigate damages and potential 811 violations, and promote best practices.

California Performance

In 2022, California had 2.8 million excavation tickets and 17.9 million locate requests.

Approximately 17% of damages occurred without prior 811 notification. PG&E provided the following information on the program metrics:

- Work Volumes: PG&E employed 303 locators in 2024, with additional contractors during peak periods.
- Public Awareness & Training: PG&E conducted 240 "811 workshops" in 2023 and offers a 10% damage cost reduction for third parties completing its training.
- Locate Activities: PG&E performed 832,814 locates in 2024 (year-to-date).
- At-Fault Dig-Ins: 51 At-Fault incidents were recorded, primarily due to marking and records errors.
- Response Times: PG&E's average response time is 19 minutes, with a stated goal of always responding within 60 minutes to damages or Grade 1 leaks within 60 minutes.

Industry Trends and Future Focus

The U.S. Infrastructure and Jobs Act has allocated $1.2 trillion for infrastructure spending, with $42.5 billion dedicated to the Broadband Equity, Access, and Deployment (BEAD) program. This funding is expected to drive a significant increase in broadband network expansions, leading to a 15% to 20% annual growth in utility locate requests over the next four years, creating more pressure on the 811 system and raising the risk of dig-ins. The ISM will continue to monitor PG&E'S programs related to the timely response for locates, marking accuracy, training effectiveness, staffing levels, and stakeholder engagement, and report on changes, as appropriate.

PG&E'S PROCESS SAFETY EXCELLENCE MANAGEMENT SYSTEM (PSEMS)

PG&E indicated that its Process Safety Excellence Management System (PSEMS) builds on the 2010 Gas Safety Excellence Management System. PSEMS is structured around four pillars: Asset Management, Pipeline Safety, Process Safety, and Safety Culture. PG&E reported that the framework is aimed to enhance safety outcomes for both the public and PG&E's workforce.

Key Pillars and Standards

The following provides a brief summary of PG&E's PSEMS pillars and associated industry standards.

- Asset Management: Aligns with PAS 55/ISO 55001 to manage infrastructure throughout its lifecycle for improved reliability and reduced risk.
- Pipeline Safety: Adheres to API 1173, focusing on systematic safety management and risk mitigation for natural gas pipelines.
- Process Safety: Follows API 754 and OSHA standards (29 CFR 1910.119) to manage hazardous chemicals and prevent catastrophic incidents.
- Safety Culture: Establishes a positive safety culture across the organization by engaging employees and stakeholders, in line with ISO 45001.

PSEMS Elements

PSEMS includes leadership engagement, community and stakeholder engagement, risk management, 'Strategy, Objectives, and Planning', operational control, training, emergency preparedness, incident reporting, contractor management, and continuous performance evaluation. PG&E reported that the system emphasizes systematic management, training, and auditing to maintain standards and to drive key safety targets, including:

- Zero public safety incidents
- Zero serious injuries or fatalities
- Reduced Days Away, Restricted, or Transferred (DART) cases
- Reduced Preventable Motor Vehicle Incidents (PMVI)

Process Safety Management

PG&E's Process Safety Management (PSM) has been applied to 22 critical facilities across its operations and aligns with OSHA's PSM requirements. Key elements include hazard analysis, operating procedures, mechanical integrity, emergency planning, and incident investigations. PG&E incorporated relevant aspects of industry process safety standards such as API 754 and API 1186 to track safety performance and assess risks from hazardous materials. These measures are aimed at preventing incidents and ensuring safe operations.

The ISM will continue to monitor the PSEMS program, and report trends and program updates, as appropriate.

MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP)

During the current ISM reporting period, the ISM interviewed PG&E's MAOP team to gain insights into their ongoing operations and areas of focus.

MAOP Reconfirmation and Subpart O Compliance Update

As highlighted in ISM Report 4, PHMSA introduced the Mega Gas Rule, effective July 1, 2020, with amendments effective May 24, 2023. These regulations establish guidelines for the initial confirmation or reconfirmation of the maximum allowable operating pressure (MAOP). for pipelines operating within specified areas, such as federally defined high consequence areas (HCA) and piggable moderate consequence areas (MCA) on pipe installed prior to July 1, 1970 with MAOP greater than 30% specified minimum yield strength (SMYS). The MAOP reconfirmation must be completed by 2035. During the current ISM reporting period, PG&E informed the ISM that it continues to refine and scope the total pipeline mileage subject to these rules to effectively schedule compliance activities and necessary tests.

PHMSA rules require MAOP reconfirmation across two pipeline operation categories:

1. Pipelines without records necessary to establish MAOP in accordance with Section (§) 192.619(a)(2) in locations that are High Consequence Areas (HCA)), or Class 3 / Class 4 – Section (§) 192.624 (a)(1).

   - This section mandates the reconfirmation of MAOP for transmission pipelines that do not have the necessary records to establish MAOP in accordance with § 192.619(a)(2). Reconfirmation must be completed by July 2035.
   - PG&E must reconfirm:
     a. 50% of applicable transmission pipe mileage by July 3, 2028.

    b. 100% of applicable transmission pipe mileage by July 2, 2035.

- Reconfirmation within 4 years of a pipe segment qualifying under Section (§) 192.624(a) or by July 2, 2035, whichever is later.
- PG&E currently identifies approximately 23 miles of pipe within this category.

2. Pipelines Installed Prior to July 1, 1970 - Section (§) 192.624(a)(2).

- Transmission pipes installed before July 1, 1970, can be designated in accordance with 192.619(c), where the MAOP for these segments may be based on the highest operating pressures observed during 5 years prior to July 1, 1970. Such designated pipelines with a MAOP exceeding 30% SMYS in an HCA, Class 3 or 4 location, or piggable MCA location must comply with Section (§) 192.624.
- PG&E currently identifies approximately 24 miles of pipe within this category.

Section (§) 192.624 provides six methods to reconfirm MAOP: pressure test, pressure reduction, Engineering Critical Assessment (ECA, specified in Section (§) 192.632), pipe replacement, pressure reduction for pipeline segments with small potential impact radius, and alternative technology. PG&E intends to use all six MAOP reconfirmation methods. Since 2020, PG&E has used Method 1: Pressure Test, Method 2: Pressure Reduction, Method 3: Engineering Critical Assessment (ECA) supported by using traceable, verifiable, and complete (TVC) data, and Method 4: Pipe Replacement.

- Method 1: Pressure Test: Strength testing has been the preferred method for longer length projects.
- Method 2: Pressure Reduction: Pressure reductions has been used where capacity reduction allow.
- Method 3: ECA supported by TVC: This involves using traceable, verifiable, and complete data or conservative assumptions applied to non-TVC data, operational history, reported incidents, material verification, and detailed threat assessments (e.g., Section (§) 192.712 Predictive Failure Pressure and remaining pipe life analysis). PG&E applied this method mainly for short sections (<100 ft) in stations where hydrotesting isn't ideal.
- Method 4: Pipe Replacement: This method has been mainly used for short section projects and if there are other drivers to replace.

PG&E stated that it prefers the above methods over the remaining methods, which include ECA supported by ILI evaluation, and alternate technology approaches until the processes are further developed.

Ongoing MAOP Efforts

PG&E's transmission asset strategy personnel continue to assess pipeline risks by segment and assign MAOP reconfirmation tests and assessments to meet regulatory deadlines. Pipe mileage that no longer meets the requirements of Section (§) 192.624 is removed from the execution schedule.

Some pipelines are being reclassified under PG&E's TransDef initiative[21] approved by the CPUC (2023), which shifts primarily pipelines that operate below 20% SMYS at pressures greater than 60 pounds per square inch to Distribution Supply Lines (DSL). PG&E reported that this reclassification affects approximately 600 miles, or 10%, of PG&E's transmission pipeline inventory. The reclassification of these pipe segments will not affect gas transmission oversight of O&M, but rather shifts the integrity management program compliance activities from Subpart O (the transmission pipeline integrity management section) to Subpart P (the distribution pipeline integrity management section). The requirements of Subpart O are more stringent than Subpart P because transmission pipelines are considered higher operating risk than distribution pipelines that include risk associated with higher operating pressures.

HCA Transmission Audit and Integrity Compliance Schedule

PG&E conducted an audit of HCA gas transmission pipelines, removing 61 miles subject to Section (§) 192.624 requirements. The same audit added 63 miles of HCA gas transmission pipelines, resulting in a net increase of 2 miles subject to these regulations.

For 2025 and 2026, PG&E has scheduled approximately 10 miles for MAOP reconfirmation tests and assessments, alongside 800 miles of transmission integrity compliance tests.

The total mileage of transmission integrity compliance testing subject to Subpart O Section (§) 192.939 and Section (§) 192.624 MAOP reconfirmation during this period is estimated at over 800 miles. PG&E indicated to the ISM that this effort will involve in-line inspections, hydrostatic strength tests, pipe segment upgrades for inspection, and ECA analyses. The following pipe threat matrix provides details on PG&E's transmission integrity compliance plan for 2025 and 2026.

Figure 20: PG&E's Schedule Subpart O and MAOP Reconfirmation Pipe Test Mileage by Year

PG&E aims to finalize the prioritization of pipe segments and the reconfirmation methods for 2025 and 2026 by the first quarter of 2025. The ISM will continue to monitor these developments and PG&E's efforts to meet the 50% MAOP reconfirmation requirement for the designated pipeline segments.

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[21] TransDef initiative relates to confirming and reconfirming the MAOP of pipelines that may lack sufficient historical records or have not undergone prior pressure testing.

IN-LINE-INSPECTION (ILI) PROGRAM UPDATE

PG&E conducts routine pipeline inspections, including ILI, to assess integrity per PHMSA regulations and its TIMP. During this ISM reporting period, the ISM interviewed PG&E's ILI leadership and conducted three PG&E pigging[22] site visits, including a pipe drying operation and two ILI projects, as described below.

Current ILI Activity and Gas System ILI Upgrade Status

During the current ISM reporting period, PG&E's ILI leadership indicated to the ISM that PG&E plans for 40 ILI projects in 2024 and 40 in 2025, with typically 10-20 classified as 'non-traditional.' The 2024 projects cover approximately 376 miles of pipelines, with 100 miles being first-time inspections. Federal regulations mandate integrity assessments on a 7-year cycle. Additional ILI projects may be used to support MAOP ECA reconfirmations (discussed above), targeting items like metal loss anomalies, mechanical damage and corrosion.

To avoid overlap with summer construction activities, PG&E shifted its ILI schedule earlier in the year, completing seven projects by March 2024. Currently, about 50% of PG&E's gas system supports ILI operations, and PG&E set a goal of increasing ILI capable pipelines to 59% over the next 14 years. PG&E indicated that risk-adjusted cost-benefits reviews of ILI upgrade projects are being performed to ensure regularly scheduled transmission pipe integrity assessments consider potential projects. PG&E noted ILI upgrade projects present the following potential challenges:

- Low pressure pipe segments that require additional conservatism when identifying retrofit locations for traditional ILI tools;
- Varying pipe diameter(s) due to legacy segment design, fittings, or obstructions;
- High land acquisition costs for ILI tool launchers and receivers;
- Complex pipe configurations that may be encountered under bodies of water, roads, or other pipe crossings; and
- Radial system configurations requiring multiple-week outages and associated customer impacts.

Although PG&E's ILI team confirms that funding is secured for pipeline integrity compliance and safety, the company adjusted its ILI upgrades and schedules based on the above referenced cost-benefit analyses leading to postponements of certain low-risk projects with:

- Where the Impact Occupancy Count is equal to zero
- Operating pressure at 20% SMYS or lower
- Low operating pressures are coupled with smaller diameters
- Pressure reduction options that do not impact gas volume, reliability, or safety

If no alternative integrity assessment options are available, PG&E reported that the ILI upgrade project will proceed as planned.

[22] These in-line processes often include the practice of inserting a physical device, commonly referred to as a "pig," into the pipeline where it travels to a designated end-point and is trapped in a "receiver" to be removed.

ILI Operation Scheduling & Data Collection

Due to the proprietary nature of certain ILI tools, PG&E utilizes tool vendors to analyze data and provide reports for review. ILI tools are calibrated before inspections using similar pipe segments (diameter, construction, and materials) with known defects.

PG&E performs a full review of pipe property data obtained during ILI projects: uploading data to the GIS system, and validating and verifying conflicts in pipe tallies, pipe seams, wall thickness, and material with as-built data.

ILI Tool Development

PG&E indicated that it contracted with a new vendor to develop robotic ILI tools for inspecting smaller pipe diameters for both in-service and out-of-service conditions. Such new ILI tools will allow PG&E to inspect 'higher risk' pipe that previously did not accommodate non-traditional (robotic) ILI tools without large pipe upgrade expense. However, these opportunities are a small percentage of total pipe mileage. During the current ISM reporting period's ISM site visit, the ISM observed a non-traditional ILI tool's ability to travel several hundred feet within a pipeline, moving with and against gas flow (discussed below).

PG&E is also co-developing a new multi-diameter, articulated, circumferential magnetic flux leakage (MFL-C) tool for 10- and 12-inch pipes. The tool is expected to be ready within a year and will allow for longer pipe segment inspections. The robotic MFL-C tool is expected to correct issues where the current Traditional 12 – and 10-inch MFL-C tool risks getting stuck due to dimensional restrictions.

Additionally, PG&E shared inspection results with the ISM associated with a new 8-inch ILI tool equipped with advanced magnetic flux leakage axial (MFL-A), MFL-C and eddy current array sensors. The tool possesses the capability to detect and measure small circumferential cracks caused by pipe bending or ground movement, providing valuable insights for targeting higher-risk pipelines. PG&E indicated favorable inspection results, both in accuracy and effectiveness, with this tool.

ILI Analysis Based Pipeline Operating Pressure Reductions

In 2024, PG&E identified 5 pipe segments requiring temporary and conditional operating pressure reductions (TROPs and CROPs) due to defects found by ILI inspections. PG&E completed repairs and restored operating pressures after the PG&E ILI team ordered direct examinations.

The traditional and non-traditional pigging tools are designed to meet specific challenges. The following sections summarize the key activities, equipment, processes, and technologies used during the inspections.

April 30th Site Visit – Pipe Drying Pigging Project

During a pigging operation following a hydrostatic test of a new 12-inch, 420-foot pipeline, PG&E employed a temporary pig launcher and receiver system. Shoring was necessary due to the excavations on city streets. Over ten foam pigs were pushed through the pipeline by pressurized air from a portable compressor to remove water and debris. Subsequently, desiccant-dried air was circulated to remove residual moisture, with success confirmed by dew meter readings at the receiver. Figure 21 depicts the inspection of a 12-inch by 24-inch foam pig after removal, showing dry foam on the interior and pipe residue on the exterior.

Figure 21: 12-inch foam pig being examined (right) after removal from receiver (left), with visible dry foam and pipe residue.

May 1st Site Visit – Winters Gas Training Facility (Pigging Loop Training)

The ISM attended a presentation at PG&E's Winters Gas Training Facility, which showcased the newly commissioned Pigging Training Loop. This loop, shaped like an elongated "S" and spanning 600 feet, was designed to mimic real-world challenges such as line-of-sight and communication difficulties. PG&E demonstrated new pigging procedures and safety protocols, with the OQ team developing performance evaluations and testing criteria. This training facility is the first of its kind, designed to assist in training staff to perform pigging operations, whereas before PG&E relied on experience and training gained while on-the-job.

May 31st Site Visit – Non-Traditional In-Service ILI

The May 31st ILI focused on a 430-foot section, located in a PHMSA-designated HCA. The inspection utilized a self-propelled robotic tool to check for axial seam and joint corrosion, prompted by a PG&E determined Selective Seam Weld Corrosion assessment deadline. The tool was loaded into a permanent pig launcher, pressurized with natural gas after air purging, with pipeline gas flow being maintained during the inspection. Figure 22 below shows the loading of the robotic ILI tool via a carrier sled.

Figure 22: Loading of the robotic ILI tool via a carrier sled.

PG&E scheduled the remaining 4.75 miles of pipeline, outside the HCA, for inspection in 2030, using a co-designed 16-inch traditional MFL-C tool, which can accommodate the restrictions in the pipeline, along with a Geometry and MFL-A tool.

PG&E provided summary comments on the Final ILI Tool Vendor Report for the assessed pipeline section. The report identified 13 metal loss anomalies with depths ranging from 10% to 15% of the nominal wall thickness. The inspection did not detect any preferential corrosion anomalies requiring repair. As a result, PG&E does not anticipate prescribing any direct inspection excavations for the pipeline.

June 3rd Site Visit – Non-Traditional Out-of-Service ILI

An out-of-service ILI was conducted on a section of pipeline constructed in 1942 with 22 to 24-inch seamless pipe. Due to regulatory deadlines for External and Internal Corrosion assessment, a re-inspection was carried out using a self-propelled robotic MFL-A tool. The pipe features historic 'bell-bell-chill-ring' (BBCR) construction, which poses challenges for traditional ILI tools due to the non-flush rings within the pipe. As the section of the subject pipe is inaccessible to pig launchers and receivers, PG&E excavated the pipeline and inserted the robotic tool directly. The loading of the robotic ILI tool, via a carrier sled, was similar to the process depicted in the prior photograph for the May 31st inspection but was directly inserted into the "cut" and out-of-service pipeline.

PG&E provided summary comments on the Final ILI Tool Vendor Report which identified 18 metal loss anomalies with depths measuring 70% wall loss. In addition, the report highlighted several smaller metal loss anomalies in close proximity to these 18 anomalies. Six of the identified anomalies are scheduled for Direct Examination excavation.

PG&E implemented an immediate precautionary 20 percent pipeline operating pressure reduction due to the breadth & depth of corrosion anomalies identified on the ILI Vendor Report to avoid any potential uncontrolled gas release until the completion of Direct Examination and pipe metal loss repairs. This temporary operating pressure reduction also provides safeguards for personnel conducting the Direct Examination.

June 3rd Site Visit – Atmospheric Corrosion Inspection

The ISM observed an atmospheric corrosion inspection of a 464-foot section of an 8.625-inch pipeline located beneath a suburban bridge in Dublin, CA. This section is part of the same pipeline inspected on May 31st. PG&E's Field Engineer explained the corrosion inspection process, which involved examining the exposed pipe for ambient rust (none was observed during the visit). The pipeline is supported 12 inches below the bridge by metal loop hangers and coated with HAA, a polyester resin powder. The pipeline's cathodic protection system includes several test stations, which are regularly monitored.

GAS DATA ASSET QUALITY IMPROVEMENTS

During the current ISM reporting period, the ISM interviewed PG&E's Gas Data Asset Management (GDAM) team to review its operations and focus areas. The GDAM team announced a new revision (Rev7) of its guideline document, that it indicated reflects progress in improving the accuracy, quality, and synchronization of critical gas data sets that share similar attributes and parameters. This new version will replace Rev6 - released in August 2023. The GDAM team indicated that specific details regarding the dataset improvements will be shared with the ISM after PG&E's management review and the official Rev7 release scheduled for September 2024.

The ISM will continue to monitor GDAM's progress in alignment with PG&E's enterprise requirements.