PG&E

INDEPENDENT SAFETY MONITOR STATUS UPDATE REPORT

March 29, 2024

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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 (PG&E) 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 Independent Safety Monitor (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) System Inspections and Repair; 2) Wildfire Risk Model Updates; 3) Vegetation Management; and 4) Fast Trip Programs. 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 is currently directed toward 1) Gas Risk Model; 2) Gas Asset Data Management; 3) Maximum Allowable Operating Pressure Program Updates; 4) In-line Inspection Program Updates; 5) Leak Management; 6) Tee Cap replacement program; and 7) Gas Quality Monitoring. These focus areas are also likely to continue evolving.

The ISM's first three reports, hereafter referred to as "ISM Report 1", "ISM Report 2" and "ISM Report 3" (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), and April 1, 2023, through September 30, 2023 (published October 4, 2023), 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 "Q1 2024 ISM Report", covers the period October 1, 2023, through March 31, 2024. It was developed based on the stipulations of the ISM Contract and the reporting directive included within CPUC Resolution M-4855. This Q1 2024 ISM Report is designed to summarize the oversight activities performed by the ISM during the period described and the related observations.

This Q1 2024 ISM Report 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 has 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 Q1 2024 ISM Report 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 Q1 2024 ISM Report. Not all topics and/or observations identified in the ISM Previous Reports will be discussed in the current report. If no new material changes or information were identified 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 is obtained. Observations may change for various reasons (e.g., additional information becomes available, operational changes are implemented by PG&E, etc.). General facts and information contained within this report have been derived 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 which have taken place at the officer level (Vice President and above) since January 2022. The organizational charts included in Figure 1 are a summary of these changes, highlighting the leadership positions that have changed two or three times, and new positions that have been added since the ISM's engagement through the end of February.

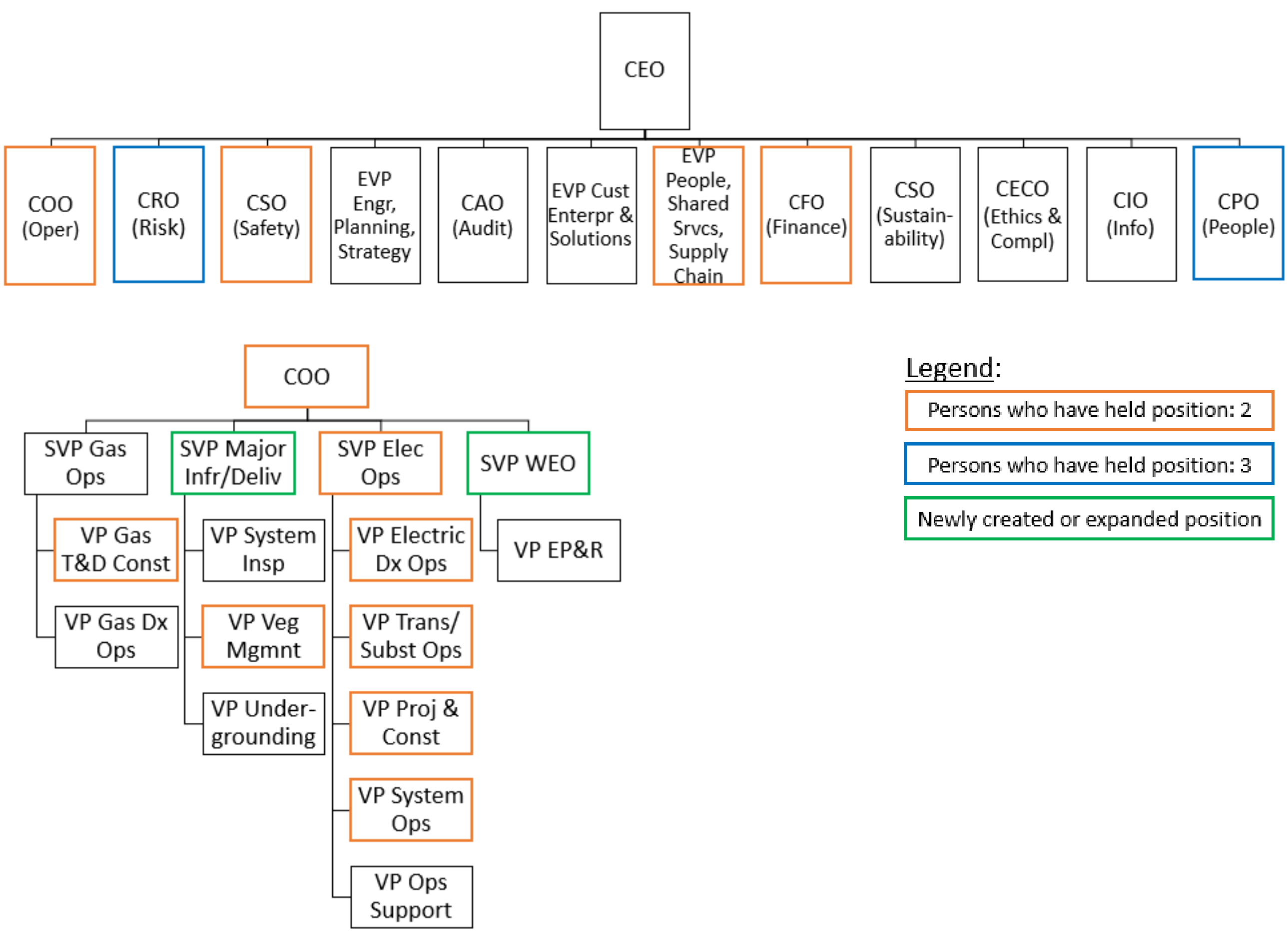

Figure 1: PG&E Senior Leadership Changes Since January 2022

As depicted in the top portion of Figure 1, 33% of the positions reporting to the Chief Executive Officer ("CEO") had two incumbents, and 17% had three incumbents. As depicted in the bottom left portion of Figure 1, 46% of the positions reporting to the Chief Operations Officer had two incumbents and 13% were newly created positions.

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:

- September 2023, Angela Sanford was hired to fill the Vice President Vegetation Management position which had been filled on an interim basis since May 2023. This change was noted in the previous report, but at that time the name of the individual had not been made public.
- In September 2023, Dave Canny was promoted to Vice President, North Coast Region. This change was noted in the previous report, but at that time the name of the individual had not been made public.
- In October 2023, PG&E announced Christine Cowsert Chapman would take on the new position of Senior Vice President, Enterprise Technology Modernization. PG&E also announced that in the interim, Raymond Thierry would return to PG&E as Lead of Gas Engineering and Service Planning & Design (Cowsert Chapman's former position).
- In December 2023, Janisse Quinones, Senior Vice President Electric Operations, resigned from PG&E. Sumeet Singh, Chief Operating Officer (Quinones' direct supervisor), assumed Janisse's duties pending an internal and external search for her successor.

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

ASSET AGE AND USEFUL LIFE

No material changes in the ISM's observations were identified during the current ISM reporting period. The ISM will continue to monitor and analyze PG&E's asset management strategies affecting asset age, useful life, and replacement timing.

ELECTRIC OPERATIONS OBSERVATIONS

HISTORICAL IGNITION TRENDS

In ISM Report 3, the ISM reported on PG&E's ignitions for the first time and detailed sources of information the ISM receives to track ignition totals and the suspected causes of ignitions over time. In this Q1 2024 ISM Report, the ISM will focus on how the 2023 ignition numbers compare against prior periods.

As seen in Figure 2, the total number of CPUC reportable ignitions in PG&E's High Fire Threat Districts (HFTD) and High Fire Risk Areas (HFRA), decreased to 65 in 2023, down approximately 29% from 2022, and down approximately 48% from the prior 2020-2022 three-year average.

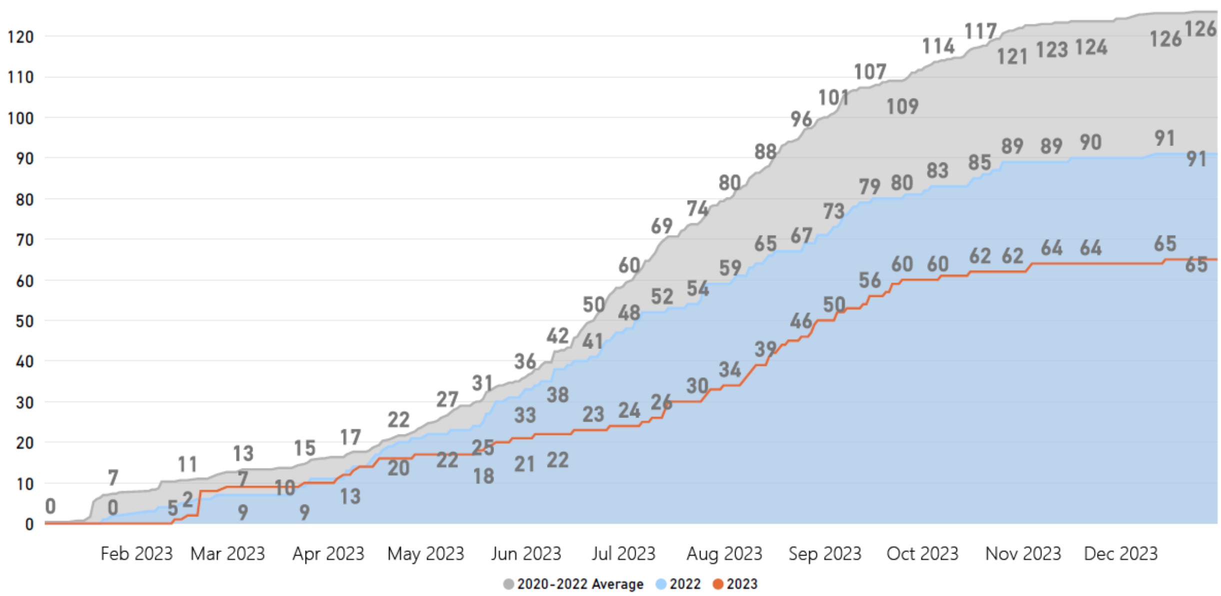

Figure 2: 2020-2023 Cumulative Reportable Facility Ignitions in HFTD + HFRA

Since weather conditions vary from year to year, and these varying weather conditions can have a significant impact on the level of ignition activity in any particular year, some form of weather normalization is required to compare ignition trends more equally over time. PG&E uses its Fire Potential Index scores as a proxy for days with higher fire spread potential in order to normalize the year-to-year ignitions data for weather. On the R1 to R5 Fire Potential Index scale, PG&E selected R3 and above days (R3+) for the basis to compare year-to-year ignition data based on an internal statistical study. In the statistical study of 2,437 historical fires (utility and non-utility caused) in its service territory greater than 100 acres in size, PG&E observed that fires starting in R3+ conditions accounted for 95% of the acres burned in this historical dataset and 100% of the fatalities and structures destroyed.

As seen in Figure 3, when PG&E considered R3+ ignition rates by 100,000 circuit mile days[1] in HFTD/HFRA, a similar weather-normalized downward trend exists. On this basis, the decrease in the normalized ignition rate between 2022 and 2023 is approximately 10%, and the decrease from the 2018-2020 three-year average (before the introduction of the Enhanced Powerline Safety Settings program) to 2023 is approximately 64%.

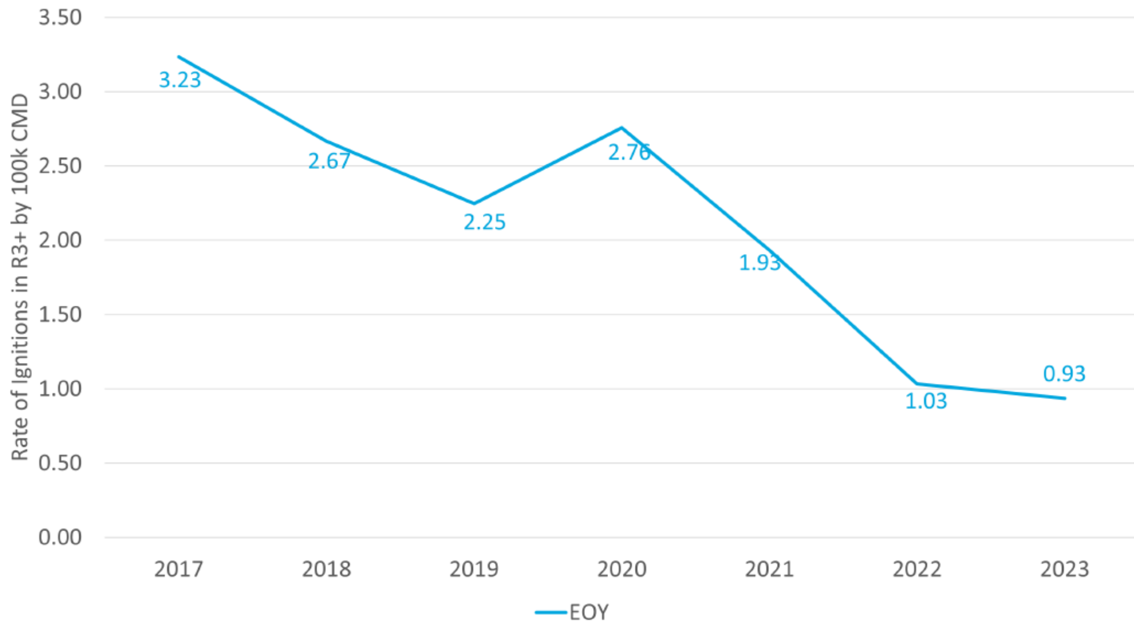

Figure 3: Weather Normalized CPUC R3+ Ignition Rates by 100k Circuit Mile Days[2]

The total of all reportable ignitions during R3+ conditions decreased from 39 in 2022 to 28 in 2023. Comparing the R3+ ignitions on PG&E's primary distribution lines, there was a drop in Vegetation caused ignitions from 14 to 5 between 2022 and 2023, an increase in Equipment related ignitions from 2 to 5, and a drop in Utility Work/Operation ignitions from 5 to 0.

WILDFIRE RISK MODEL UPDATES

In the ISM Previous Reports, the refinements of PG&E's wildfire risk models over the past five years were discussed.[3] During the current ISM reporting period, PG&E introduced three updated risk models. Both the latest version of the Wildfire Distribution Risk Model (WDRM v4), approved for use by PG&E in January 2024, and the Wildfire Transmission Risk Model (WTRM v2), approved for use in August 2023, separately calculate the annual probability of ignition for the respective distribution and transmission assets. To calculate the total wildfire

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[1] In this case, circuit mile days is calculated as the number of circuit miles that are at R3+ conditions multiplied by the number of days those miles are under R3+ conditions.

[2] 2021 was a transitional year where EPSS settings were enabled for part of the year.

[3] E.g., incorporating such things as advanced machine learning, broader categories of ignition sources, greater geographic granularity and environmental inputs, updated ground fuels, and the use of more advanced wildfire spread and consequence formulation over time.

risk associated with each PG&E facility, these ignition probabilities are multiplied against the projected consequences of an ignition occurring at specific asset locations. The updated version of the Wildfire Consequence Model (WFC v4), also approved for use in January 2024, calculates these wildfire consequence risks (independent of PG&E facility ignition source), and is incorporated equally into both WDRM v4 and WTRM v2.

Wildfire Consequences Model v4

WFC v4 provides coverage across all HFTD areas (Tiers 2 and 3) plus burnable areas of non-HFTD and utilizes asset locations and configurations as of January 2023. PG&E's 2023-2025 Wildfire Mitigation Plan (WMP) and subsequent updates provide details on key enhancements to WFC v4,[4] so these enhancements are not detailed in this Q1 2024 ISM Report.

The large increase in fire history data and the extension of the fire simulation period from 8 to 24-hours resulted in a greater range and contrast between the high and low consequence values. PG&E's introduction of new fire suppression and egress factors also resulted in a geographic shifting of consequence risk. In ISM Report 3, the ISM observed that PG&E conducted several statistical evaluations of different egress and fire suppression modeling methods prior to selecting its preferred simulation methods. By incorporating the Technosylva Terrain Difficulty Index[5] to guide predicting difficulties for fighting a wildfire and using Access and Functional Needs concentration as a proxy for residential egress mobility, WFC v4 increases consequences in rough and/or rural terrain, the edges of cities, and areas away from major roads. Additionally, it decreases consequences in areas of flat and/or readily accessible terrain. Further information on the total risk score shifts is presented in the following two sections.

Wildfire Distribution Risk Model v4

While PG&E asserts that the wildfire model enhancements are allowing PG&E to better target its wildfire mitigation efforts to areas deemed higher in risk for wildfire, PG&E continues to see significant shifting of risk ranking among its electric distribution circuits. However, these most recent shifts are not as large as those reported in ISM Previous Reports between WDRM's Version 1 (2019), Version 2 (2021) and Version 3 (2022).

WDRM v4 covers all of PG&E's service territory (as did WDRM v3), uses asset locations and configurations as of January 2023 (versus January 2022 for WDRM v3), and incorporates fire events, outages, and ignitions from 2015-2022 (versus January 2015-2021 for WDRM v3). The primary changes to the probability of ignition portion of WDRM v4 include the following:

- Vegetation: adding tree health, wind direction, new satellite tree canopy density, drought indices and climatic water deficits;

[4] These enhancements include historical fire dataset quality improvements, fire simulation upgrades, adding dry wind conditions, and the introduction of egress and fire suppression factors.

[5] The Technosylva Terrain Difficulty Index (TDI) is a composite index that incorporates spatial estimates of accessibility, penetrability, and the ability of fire resources to establish a fire line. TDI is presented in integer values ranging from Level 1 to Level 5 (more severe terrain difficulty) and is used to predict fraction of building loss from a fire.

- Model granularity: prior versions were modeled at the 100m x 100m pixel level and support structures and transformers were also composited at the mean pixel level. WDRM v4 now incorporates specific asset locations and can composite at the risk per line mile;
- Conductors: adding wire down, line slap and splice data;
- Additional equipment: WDRM v4 now contains specific predictions on capacitor banks, voltage regulators, switches, fuses, and distribution protection devices.

WDRM v4 continues to incorporate the risk-reducing impacts of mitigations from prior years. Examples of this include prior years' Enhanced Vegetation Management activities, completed system hardening/line undergrounding, or the risk associated with the increase or decrease in the repair tag backlog described in a later section. In the latter instance, each open repair tag at the time of model iteration is given its own risk score. When questioned by the ISM, PG&E indicated that no risk differentiation was given to the priority of the repair tag. Instead, PG&E indicated that the type of identified equipment/damage was deemed more predictive for risk modeling activities.

In determining whether WDRM v4 improves predictive ability,[6] PG&E uses an Area Under the Receiver Operator Curve (AUC) evaluation method.[7] For the system hardening composite model[8], the AUC for probability of ignition has increased from 0.68 to 0.74; and for the vegetation composite model, the AUC for probability of ignition has remained the same at 0.78. The AUC scores for vegetation-trunk, vegetation-branch and vegetation-other (the leading causes of identified unplanned outages and ignitions), AUC scores were 0.83, 0.82, and 0.77, respectively.

As seen in Figure 4, WDRM v4 risk is more evenly distributed across the service territory compared to WDRM v3, with more wildfire risk captured in Sonoma and Fresno and coastal counties. As noted from the WDRM v4 consequences sub-model, there is a general risk shift to more remote locations due to the manner in which PG&E modeled egress and fire suppression variables, and the interaction of the fire potential index and dry wind conditions resulted in an east to west shift from higher elevations in the Sierras to the western slopes of the Sierras.

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[6] Predictive ability includes learning with older years data and testing its predictive ability against a more recent year data.

[7] With this AUC method, a score less than or equal 0.5 is no discrimination (i.e., no better than guessing), while a score of >0.5 to 0.7 is poor discrimination, >0.7 to 0.8 is acceptable discrimination, >0.8 to 0.9 is excellent discrimination, and a score of >.9 is outstanding discrimination.

[8] In total there are 23 event probability models. Detailed are the two main composite models (system hardening and vegetation) as well as three of the top sub-models (veg-trunk, veg-branch, veg-other) linked to ignitions.

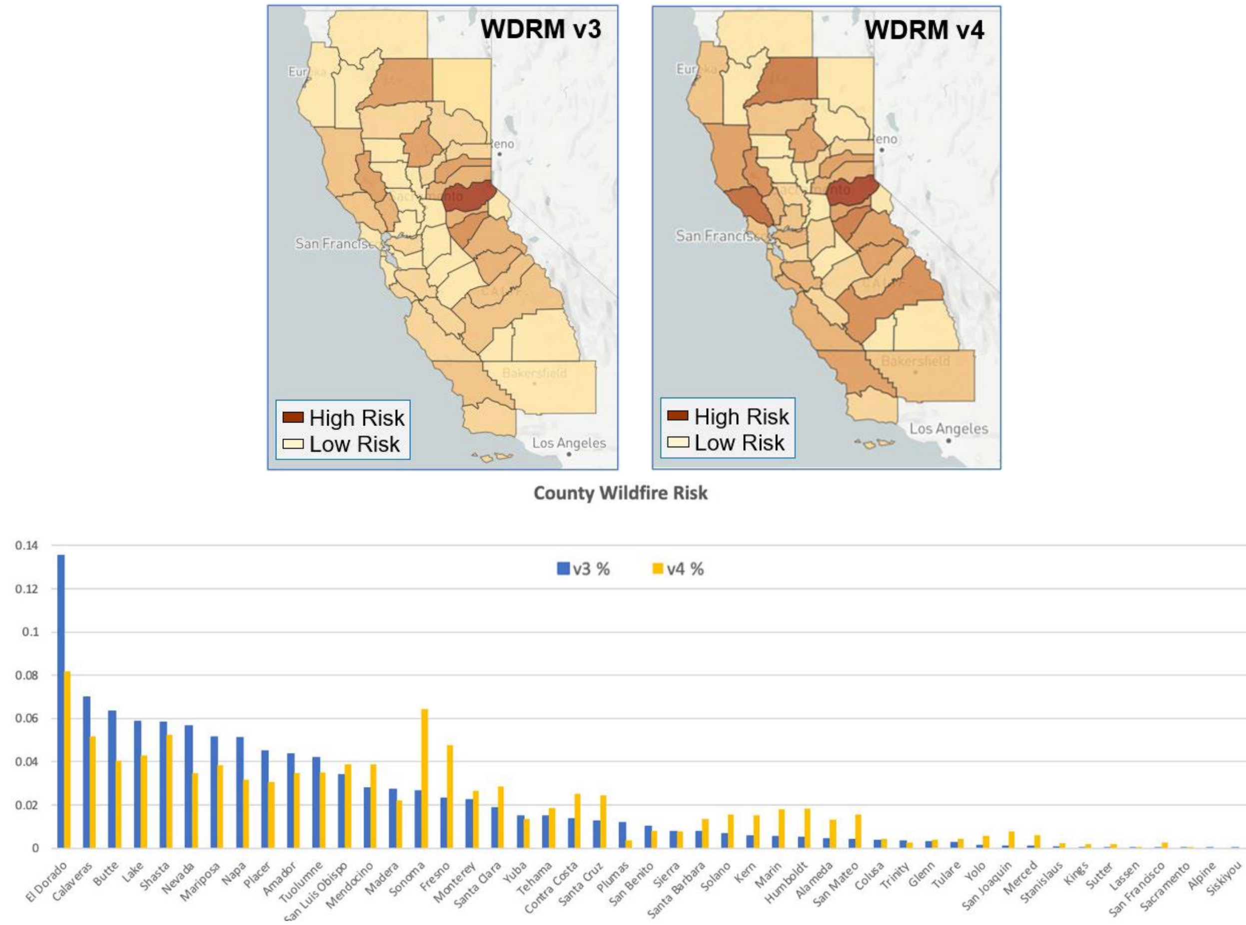

Figure 4: WDRM v3 and v4 Country Risk Comparison

The broadening of risk across the service territory is also seen in the flattening of the risk buydown curve. Whereas, using WDRM v3, the top 80% of total HFTD risk was covered in 715 circuit segments (9,795 HFTD miles); using WDRM v4, the same 80% of risk is covered in 1,432 circuit segments (14,626 HFTD miles).

As seen in Figure 5, PG&E asserts that one key benefit to adding additional causes of ignition and equipment failure to the WDRM v4 model is that PG&E can create specific sub-models to better align with asset and circuit segment specific work planning. Further, PG&E asserts that shifting from 100m x 100m pixels in WDRM v3 to asset level predictions in WDRM v4 also provides one risk value per asset, allowing for improved 1:1 alignment with work planning, and allows for easier compositing of asset risk scores along select distribution lines.

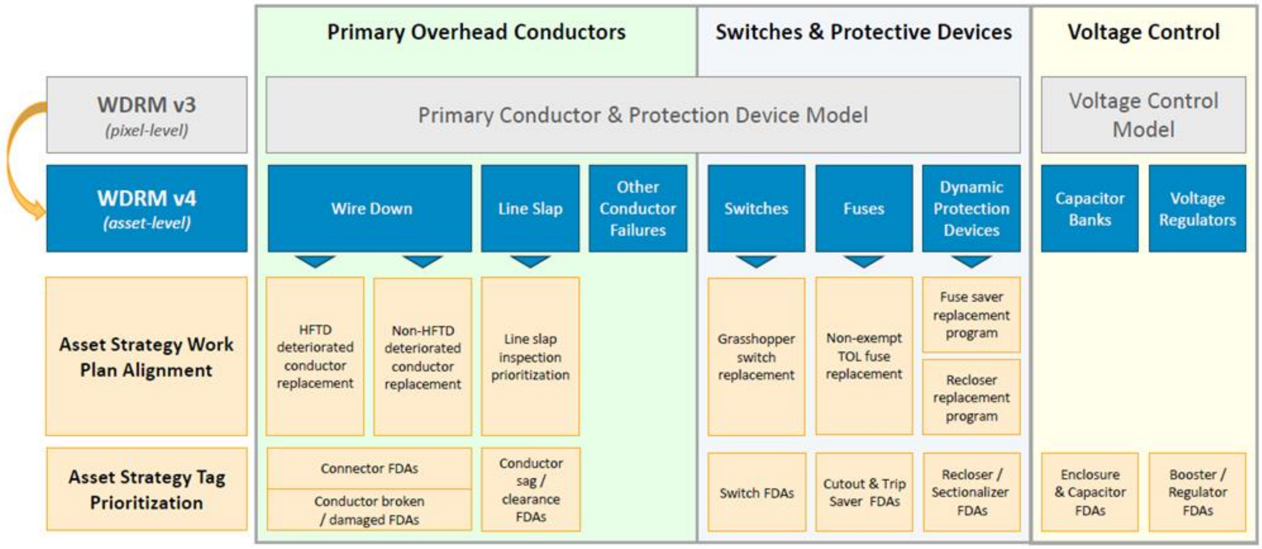

Figure 5: Equipment Failures Alignment with Asset Strategy Work Planning

The timing of when the WDRM v4 model will start to guide future work is dependent upon the flexibility that each electrical operations group has in adjusting its workplans. During the current ISM period, the ISM observed discussions among the various electrical operations groups as to when WDRM v4 might start being used for work planning purposes. Whereas the systems inspection group is investigating whether it can begin to utilize WDRM v4 to set its risk-based inspection cycles at the beginning of 2025, the group responsible for systems hardening/undergrounding believes it may take several years before WDRM v4 risk ranked work will start to be seen in the field. Per ISM discussions with PG&E leadership, the variance in implementation timing by various operational groups is due to longer-term asset enhancement and line rebuild projects (like undergrounding) often requiring several years to scope, design, estimate and permit. Numerous systems hardening projects are well underway, having been selected based upon the risk ranking of WDRM v3. As noted in ISM Previous Reports, PG&E leadership indicated that PG&E no longer halts and abandons "in-process" systems hardening work when a new version of the risk model subsequently downgrades the risk ranking of a circuit. PG&E indicated that when a risk ranking changes, PG&E continues with the project to completion once selected. At the January 2024 WDRM v4 model approval meeting, the ISM also observed consideration being given by PG&E leadership as to whether future versions of the risk models should be updated less frequently, and more in alignment with the 3-year WMP and general rate case cycles, to better match up with longer term capital project planning.

Figure 6 below shows how both the probability of ignition, and the total risk (POI x Consequences) shifted between WDRM v3 and WDRM v4 across all threats. These risk rank changes can differ for each specific asset or ignition cause sub-model (e.g., system hardening undergrounding, vegetation trunk/branch, asset inspections etc.). In later sections of this Q1 2024 ISM Report, the ISM presents the WDRM v3 to WDRM v4 risk rank changes specific to system inspections and reviews the risk rank changes from a maintenance tag backlog perspective.

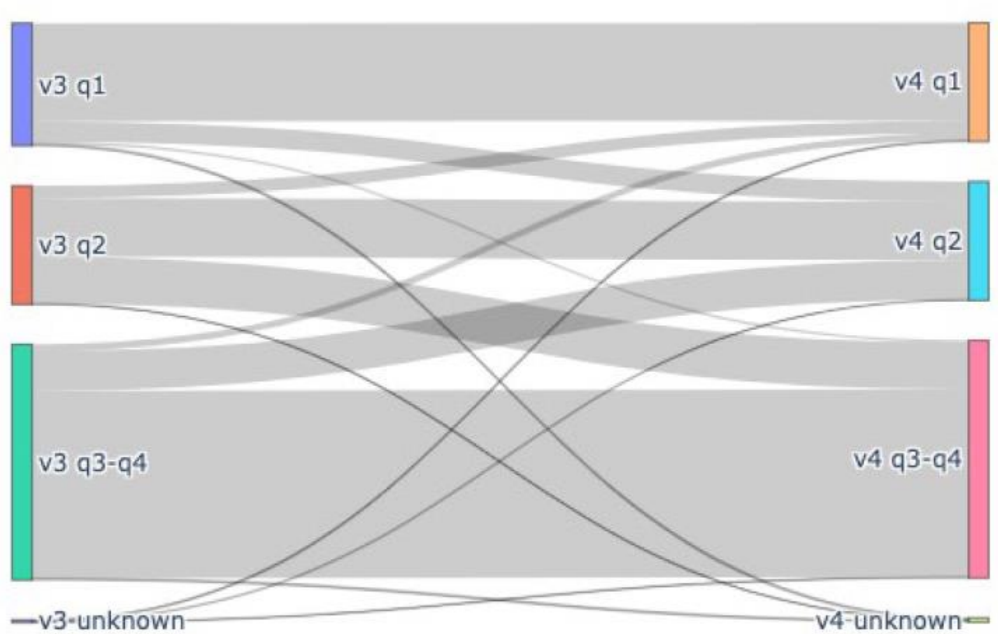

Figure 6: Movement of Mean Circuit Segment Wildfire Risk from WDRM v3 to WDRM v4[9]

Wildfire Transmission Risk Model v2

PG&E's initial version of its Wildfire Transmission Risk Model was based upon a separate Operability Assessment (OA) model which determined the probability that a transmission asset, such as a tower or pole structure (including the equipment and conductors it supports), might fail during wind gusts of a given speed. While wind speed is the intensity measure used to determine this probability, the OA model also considered damage to mechanisms, such as corrosion, fatigue, wear, and decay that could lower the capacity of an asset to resist extreme winds. Following the development of the OA model, PG&E created a separate Transmission Composite Model (TCM). The TCM was similar to the WDRM in that the TCM also calculated an annualized probability of failure and wildfire consequence.

In WTRM v2, the code base and data infrastructure for the OA and TCM models have been merged, and several new model elements have been added. These include:

- Vegetation hazard model:[10] a new machine learning model using transmission line outages as its inputs, designed to be used for annual VM planning. Weather (precipitation and water deficit) and strike tree related attributes (count and height) are the largest drivers of the likelihood of failure in the model;

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[9] The reference to 'v4-unknown' in this Figure are for circuit segments that existed in WDRM v3 but were later reconfigured and are no longer part of the 2023 GIS vintage used in the WDRM v4 model. The reference to 'v3-unknown' is for circuit segments that did not exist in the 2022 GIS vintage used in the WDRM v3 model, but that were newly created via additional sectionalization or new build, included in the WDRM v4 model.

[10] PG&E determined AUC value of 0.92.

- Avian hazard model:[11] a new machine learning model using transmission line bird caused outages as its inputs. This model indicates that the type of structure is the largest driver behind avian caused failures;
- Above Grade Hardware (AGH) mechanical wear model v2:[12] a first principles-based/machine learning hybrid model using repair tags for wear of cold-end hardware as its dataset. In this model, hardware age is the most important feature in determining AGH failures, and old suspension lattice towers on steep slopes with long spans are the most prone to mechanical wear;
- Atmospheric corrosion model: an updated first principles-based model using ultrasonic thickness test results on structures as its dataset. PG&E asserts that the version of this model in WTRM v1 was conservative with respect to prediction of wall loss compared to PG&E field measurements. The new atmospheric corrosion model used in the WTRM v2 incorporates testing by PG&E's Applied Technology Service lab, which PG&E asserts results in a 36% reduction in average error with respect to predicted wall loss compared to PG&E field measurements; and
- Polymer insulator degradation model: a first principles-based model using replacement tags[13] for polymer insulators for its dataset. For validation, PG&E determined that assets with the highest modeled polymer insulator degradation were eight times more likely to have a replacement tag versus those with the lowest.

In addition to these new and enhanced models, several other new features have been introduced, including 1) a refinement of the wood decay model which adds historical pole reinforcements to address pole failure over-estimation, and 2) the introduction of a new logic update that attributes wind as the cause of certain 'unknown' cause outages, where wind was shown to be a correlating factor.[14]

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[11] PG&E determined AUC value 0.78.

[12] PG&E determined AUC value of 0.91.

[13] 1,642 from 2008-2023.

[14] This increased the outage dataset from approximately 300 to 5,400 and led to more transmission lines being encompassed by the model.

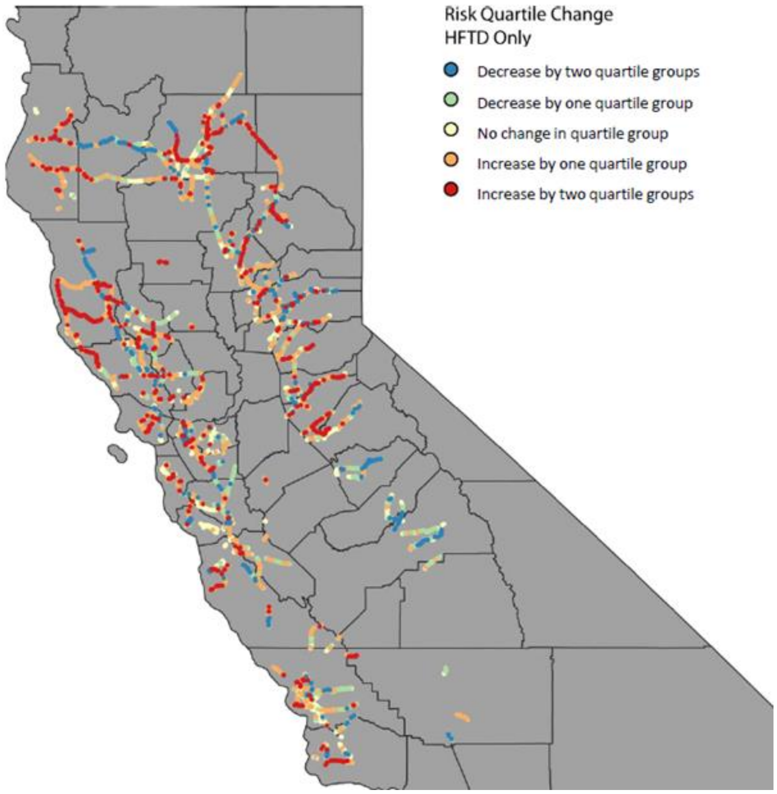

Figure 7: Shift in Transmission HFTD Wildfire Risk WTRM v1 vs v2

The largest driver behind the probability of ignition changes was the logic update that attributed wind causes to correlated Unknown outages/ignitions. This accounted for between 80 and 90% of the changes in both directions (highest to lowest, and lowest to highest). Areas with lower average wind speeds, such as the South Sierra Regions, saw a corresponding reduction in ignition risk. Figure 7 above shows the areas where the transmission line risk rankings in HFTD have changed between WTRM v1 and WTRM v2.

PG&E data showed that approximately 67% of all wildfire risk in HFTD was on the 60 and 70 kV lines, 32% was on the 115 and 230 kV lines, and 1% was on the 500 kV lines. After normalizing for the number of structures, the disparity of risk was evened with the 60 and 70 kV lines constituting 47% of the wildfire risk, the 115 and 230 kV lines having 48% of the wildfire risk and the 500 kV lines having 5% of the structure normalized risk. PG&E data showed that the risk buy-down curve for transmission is much steeper than distribution, and the top 90% of HFTD risk is contained on 17% of structures in WTRM v2, up from 13% in WTRM v1, indicating that the WTRM v2 risk is more broadly dispersed.

Figure 8 provides an overview of how the risk rankings changed between the two versions, with a little more than 50% of the first quartile of risk in WTRM v1 remaining in the same quartile in WTRM v2. As with the WDRM v4 model, both models are more heavily influenced by the WFC v4 consequence risk changes since consequence risk changes have historically been weighted more heavily than the probability of ignition changes models.

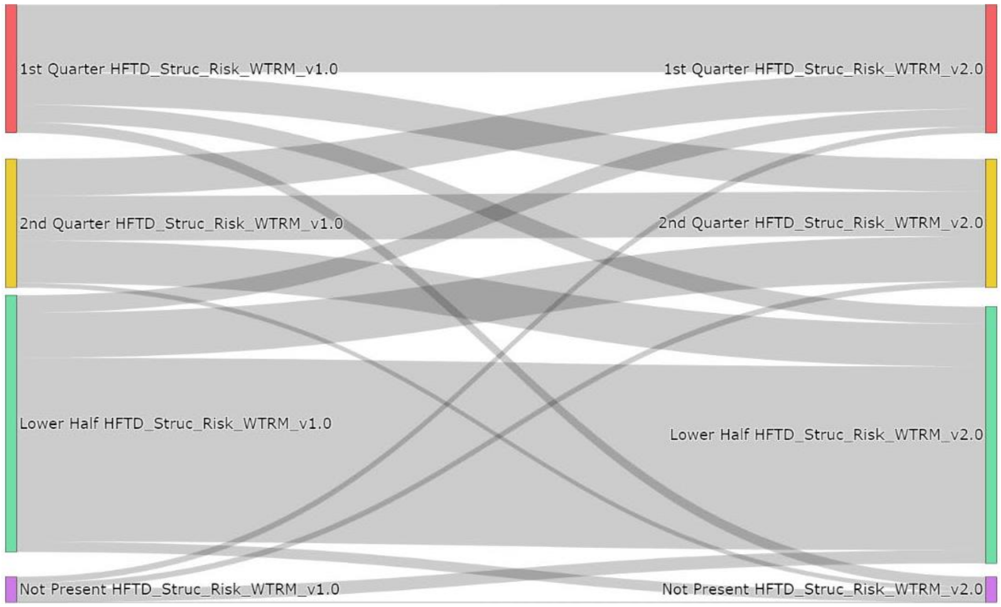

Figure 8: Structure Level Annual Wildfire Risk: WTRM v1 vs. v2

The OA portion of the model focuses on conditional probability of failure in high wind conditions, and WTRM v2 is currently being used for PSPS planning. The TCM portion of the WTRM v2 model, which focuses on annualized probability of failures, is currently being used for longer-term asset strategy, such as inspections, pilot programs, non-HFTD tag prioritization, and short- and long-term investments.

FAST TRIP SETTING 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 of these fast trip mitigations versus prior periods, (2) describing any supplemental fast trip mitigation expansions and modifications, (3) reviewing the ongoing ignition reduction impact achieved, and (4) describing the efforts being undertaken to help reduce the frequency and duration of fast trip outages.

Enhanced Powerline Safety Settings (EPSS) Performance Updates

During the current ISM reporting period, the ISM observed that at the end of 2023 PG&E further expanded EPSS coverage, with 4,688 devices (up 15% from end of year 2022) on 915 circuits (up 5% from end of year 2022), providing EPSS coverage along approximately 44,100 distribution miles (up 29% from end of year 2022) servicing approximately 1.6 million customers (up 44% from end of year 2022). Approximately 42,000 miles of the above EPSS capable miles were enabled in 2023, with approximately 2,100 miles not experiencing wildfire risk conditions which met PG&E's minimum enablement criteria. This compares to approximately 34,100 miles that were EPSS enabled in 2022. Despite the expansion of EPSS coverage in 2023, these lines saw lower aggregate EPSS enablement versus 2022. This was due to 2023 having less time where the environmental conditions at these EPSS capable lines met the minimum wildfire risk EPSS enablement criteria (21.3% circuit miles days experiencing Fire Potential Index scores of R3+ versus 33.0% in 2022). In aggregate, there were a total of approximately 276 billion customer minutes where EPSS lines were enabled[15] in 2023 versus approximately 238 billion in 2022. The total number of circuit mile days where EPSS lines were enabled[16] was also lower, with approximately 5.75 million in 2023 versus approximately 6.15 million in 2022.

Table 1 provides a comparison of certain EPSS performance between 2022 and 2023. The ISM did not include a comparison against 2021, as the EPSS program was initially piloted in 2021 for only a portion of the year in certain HFTD areas. During the current ISM reporting period, EPSS enablement covered 100% of the High Fire Risk Area (HFRA), plus approximately 9,600 buffer area miles selected for their potential to experience ignitions which could lead to wildfires capable of spreading into the HFRA, as well as approximately 9,200 additional miles that are a bi-product from protection being on radial lines with extra miles either upstream or downstream from PG&E's HFRA and buffer areas.

As seen in Table 1, from 2022 to 2023 the number of EPSS outages decreased by 5%, from 2,379 to 2,263; and the number of CPUC reportable ignitions on EPSS enabled lines in HFTD/HFRA decreased 29% for the same period, from 31 to 22. PG&E's average response time for these 22 fire ignitions was 40 minutes versus 49 minutes for the 31 ignitions reported in the prior year.

During the current ISM reporting period, the ISM observed that across all HFTDs, including times when EPSS was both enabled and disabled, total CPUC reportable ignitions were 65 in 2023 versus 90 in 2022 and an average of 126 over the prior three-year period.

Although the number of EPSS protected miles in 2023 increased by 29% over the prior year, PG&E reported that it reduced the total number of customers experiencing EPSS outages by approximately 6%. PG&E also reported reducing its average response time by approximately 17%, and increasing the number of customers that were restored within 60 minutes of the outage by 56%. PG&E reported the average time to restore customers experiencing EPSS related outages increased by approximately 5%, and the number of restorations taking longer than 12 hours also increased by 19%. PG&E attributed these increases to the number of high intensity storms experienced in its service territory in the early part of 2023, and the deployment of personnel to post-storm restoration work. The impact of these storms is also reflected in the increased number of outages attributable to Environmental/External conditions in Table 1.

As seen in Table 1, there are some notable changes to percentages of EPSS outages attributed to different causes. Further, discussions on changes to the "Unknown" classified outages and

[15] Customer minutes are the total aggregate of customers across all days a circuit was enabled in EPSS settings multiplied by the number of minutes in a day.

[16] Circuit mile days are the total aggregate of miles across all days a circuit was enabled in EPSS settings.

to Equipment caused outages are detailed further in this section.

While PG&E reports that the fast trip programs effectively helped reduce the number of ignitions and wildfires, PG&E customers protected by this program experienced additional unplanned power interruptions. PG&E data reviewed by the ISM indicates that in 2023, a total of approximately 727,000 customers experienced at least one EPSS outage (approximately 6% lower than 2022), and approximately 102,000 customers experienced 5 or more EPSS outages (14% lower than 2022). The highest number of outages on an individual circuit was 29 in 2023 and 15 in 2022.

Table 1: EPSS Data 2022 versus 2023

	2022	2023
EPSS Outages	2,379	2,263
Ignitions on EPSS Enabled Lines	31	22
EPSS CAIDI (min)	176	193
Response Time Within 60 minutes	89%	91%
Average Response Time (min)	54	45
Average Full Restoration Time (min)	351	367
% Restorations <= 60 minutes	7.4%	11.6%
% Restorations > 12 hours	13.3%	16.0%
Total Customers Experiencing EPSS Outages	2,083,985	1,972,285
Unique Customers Experiencing EPSS Outages	770,441	726,708
Medical Baseline Customers	134,622	129,825
Life Support Customers	93,876	92,674
Critical Customers	34,841	33,456
Schools	4,573	4,301
Hospitals	185	260
Well Water Dependent customers	2,375	4,344
Outage Cause (% of total)		
3rd Party	9.5%	9.6%
Animal	16.5%	12.2%
Company Initiated	4.5%	11.3%
Environmental/External	0.5%	3.2%
Equipment	12.3%	13.6%
Unknown	45.6%	39.2%
Vegetation	11.2%	10.9%

During the current ISM reporting period, the ISM interviewed PG&E management and inquired as to whether the impacts to customers on some of these high outage EPSS enabled circuits outweighs the wildfire risk reduction, and whether PG&E has considered disabling EPSS on select high outage circuits. PG&E management noted that its intentions are to continue to reduce such outages through targeted mitigation activities, which are described further below. PG&E also noted that high outage circuits may not experience the same frequency of outages from year to year. The ISM observed this variability, with the circuit which experienced the highest number of EPSS outages (29) in 2023, having customers which experienced 6 to 7 EPSS outages in 2022. In 2022, the circuit with the highest number of EPSS outages (15) experienced 10 to 13 EPSS outages in 2023.

EPSS Operational Improvement and Mitigation Programs

As reported in ISM Previous Reports, PG&E introduced programs designed to reduce the high number of EPSS outages classified as 'Unknown' cause. PG&E personnel indicated that the likely causes for most of the Unknown EPSS outages were bird, animal, or tree branch contacts, where the patrols were unable to find any evidence of such contact. PG&E's key performance indicator target for 2023 was to reduce the percentage of outages of Unknown cause to below 40%. PG&E reported that it achieved the goal, with 39.2% Unknown in 2023. In order to improve its cause identification, PG&E implemented a more rigorous outage review program in 2023, and during the year, 252 outages originally classified as unknown were later reclassified (e.g., 83 to Equipment Failure, 79 to Company Initiated, 39 to Environmental/External, 19 to Animal Contact, 18 to 3rd Party Contact etc.). Prior to these reclassifications, the percentage of EPSS outages originally classified as Unknown was approximately 50.4%. More accurate reclassification allows PG&E to better understand causes that may be behind repeat multiple outages and may also allow for better deployment of supplemental wildfire mitigation methods (such as installing more animal guards or identifying where to deploy more targeted vegetation management).

During the current ISM reporting period, the ISM observed that PG&E continued with its Multiple Outage Review (MORE) program on high outage circuits. In 2022, over 200 circuits underwent these in-depth reviews, generating approximately 1,400 action items. This program continued into 2023, with a mid-year shift from circuit level reviews to device level reviews. In 2023, 13 additional circuits and 154 devices received detailed MORE reviews (with several of these circuits and devices being on their second or third review), generating an additional 340 MORE action items. These include recommendations for things such as animal guards, accelerated project timelines, additional outage information gathering, requests for additional detailed patrols, and sectionalization and fault indicator assessments.

One refinement of the MORE program in 2023 is that PG&E is focusing its reviews on shorter circuit protection zone segments, rather than full circuits, which allows for a more targeted approach to seeking reliability improvements on circuit segments experiencing multiple EPSS outages. Additional distribution line sectionalization also helps isolate an EPSS outage to shorter circuit segments, which in turn allows faster restoration of service for more customers. During 2023, PG&E installed approximately 200 additional sectionalizing devices on the most reliability-challenged circuit protection zones to help reduce customer count exposure should a fault occur. PG&E indicated that it plans to install an additional 200 devices in 2024.

Per PG&E, continued installation of new fault indicators was one of the contributors in achieving a steady improvement in full average restoration times throughout 2022, and the continuing smaller improvements seen in 2023. PG&E installed approximately 1,600 fault indicators in 2022, approximately 1,360 in 2023, and PG&E plans to install approximately

1,200 more in 2024. These fault indicators allow patrolling personnel to identify the section of the line more quickly where the EPSS outage may have occurred and allows earlier sectionalizing to restore power to select customers faster.

A new program that PG&E started in 2023 is the installation of EPSS devices on single phase distribution lines. PG&E projects that these new installations will further reduce customer reliability impacts by allowing smaller sections of single-phase circuits to be tripped during an outage event, rather than having an upstream three-phase device trip, which could cause an outage to more customers. In 2022, 34,000 customers served by single-phase lines experienced at least one EPSS outage and 2,200 experienced five or more EPSS outages on single phase distribution lines. In the prior ISM Report 3, the ISM reported that PG&E intended to install 67 new EPSS devices on eligible single-phase lines in 2023 that PG&E estimated might allow approximately 67,500 customers to be descoped and removed from EPSS coverage (since they reside outside HFTD and can be isolated from the portions of the lines within HFTD) or added to the EPSS buffer areas. The ISM confirmed that PG&E installed 65 new EPSS devices in 2023, and that approximately 34,300 service points on these single-phase lines were shifted from the HFRA to the EPSS buffer area or descoped.

Another new program that PG&E began piloting in 2023 involved the installation of Gridscope devices. These are shoebox-sized, solar powered units that mount to a power pole, and are designed to detect anomalies using highly sensitive sensors, including a vibrometer and microphone. By continuously taking real-time measurements at a rate of 6,000 times per second, the Gridscope can observe the grid's environment, stress levels and equipment response. Any deviation from the expected behavior could indicate issues (e.g., a branch falling on the line, a strong wind gust blowing a line down, a car striking the post, etc.). PG&E began installing these devices in June 2023, and by year end installed approximately 1,500 of the approximate 1,900 devices it anticipated completing by the end of the first quarter of 2024. With this pilot program, PG&E is testing if these devices can help narrow down fault types and locations, improve fault cause (further reducing the number of Unknown outages), and improve restoration times by getting personnel to the fault location quicker.

As reported in ISM Previous Reports, PG&E allocated the EPSS program an additional $50 million per year to fund mitigations on circuits experiencing the highest frequency of EPSS outages. This includes funding directed toward items previously identified during PG&E's MORE analysis, such as animal guard retrofit (e.g., birds and squirrels), additional targeted vegetation management, and customer resiliency programs.

PG&E reported that due to securing funding late, a resourcing gap following early year storms, and the need to focus on critical work, it was unable to achieve its initial proactive animal mitigation targets for 2023. A total of approximately 1,150 poles were inspected in 2023 (versus the target of approximately 3,500), and approximately 180 animal guards were installed in 2023 (versus the target of 500) across 4 circuit segments as part of the Proactive Animal workstream. For 2024, a total of approximately 2,270 poles are to be inspected for possible animal guard additions under this proactive animal mitigation program. In selecting the circuits for inspection and animal guard installation, PG&E is initially focusing on 12 circuit segments, covering 167 miles that collectively experienced 31 animal caused EPSS outages, and 22 Unknown cause outages (where animal contact may have been a likely cause).

The targeted vegetation management program (Vegetation Management for Operational Mitigations or "VMOMs") for circuits with multiple vegetation caused outages achieved all of its targets for 2023[17]. The VMOM program is described in greater detail later in this Q1 2024 ISM Report.

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 that PG&E continued installation of additional DCD devices, adding approximately 700 in 2023 to the 400 installed during 2022, bringing the total number of devices to approximately 1,100, and expanding the HFRA coverage from approximately 3,400 to approximately 17,900 miles. PG&E indicated that its plans for 2024 are to add an additional 400 devices, bringing the total coverage to approximately 20,500 miles in HFRA that are DCD capable. PG&E's prioritization of the installations was based upon the circuit risk ranking from WDRM v3.

During the current ISM reporting period, the ISM observed there were approximately 330 DCD outages in 2023, with the largest causes being Company Initiated (39%), Unknown (37%), Equipment Failure (12%), Vegetation (5%), with Animal, 3rd Party and Environmental making up the remaining 7%. PG&E informed the ISM that the number of Company Initiated outages was due to problems with software algorithms in the devices as the program was scaled over the larger number of devices in 2023. The issue caused a larger number of nuisance trips, and PG&E is working to update the equipment firmware to resolve the issue.

As a result of post-outage patrols, PG&E identified 17 line-to-ground fault-type incidents in 2023 where DCD likely mitigated ignitions (8 associated with vegetation contacts, 7 with equipment failures and two with animal contacts).

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

The other EPSS program enhancement which 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 the prior ISM Report 3.

During 2022, a total of 36 PVFO outages occurred, with 11 field hazards identified. During 2023, 25 PVFO outages occurred, with 21 field hazards identified. The average response time in 2022 was 11 minutes versus 17 minutes in 2023.

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[17] This is funded under the same $50 million program as the proactive animal mitigation.

DISTRIBUTION INFRASTRUCTURE INSPECTIONS & STRATEGY

Program Modifications

Introduction of X Tags within Inspections

During the current ISM reporting period, PG&E indicated that it is changing its tag classification system to differentiate the handling of critical notifications for its distribution system repairs. PG&E is introducing a new X tag to its classifications, which prioritizes notifications that require urgent attention but do not require an inspector to stay on site nor require resources to be pulled away from a job to mitigate the hazard immediately. The existing tag classification at PG&E consists of four primary tag priorities that multiple functional areas can utilize:

- A Tags: These require immediate completion and require the inspector to stay on site until the hazard has been mitigated. They signify Level 1 notification indicating an immediate risk to safety and reliability.
- B Tags: Original completion was expected within 90 days. With the introduction of the X Tags, this completion time will be extended to 180 days, in line with GO 95 Rule 18 timelines for Level 2 notifications. Level 2 notifications indicate at least a moderate potential impact.
- E Tags: Completion timelines vary, ranging from 6 months for Tier 3 to 36 months for non-HFTD. They are also classified as Level 2 notifications, but with a perceived lower potential safety or reliability impact than B tags.
- F Tags: These are Level 3 notifications with low potential safety or reliability impact, which have a completion time of 5 years.

PG&E's new X Tags are classified as a Level 2 condition which will require completion within 7 days. PG&E indicated that the X tag implementation is planned for mid-March 2024, contingent upon the completion of SAP system modifications, and the setup of the modified inspection checklist. In order to verify the appropriate prioritization of A, X, and B tags, inspectors will initiate a phone call to their Supervisor or a Systems Inspections Inspection Review Specialist[18] (IRS), thus, streamlining the identification process and aiming to attain correct identification and prompt handling of these high priority notifications. By not requiring inspectors to remain on site until completion, and not requiring immediate repair, PG&E's leadership has indicated that the X tag introduction will help prevent work crews from being diverted from ongoing projects and will 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. PG&E states that this new approach also minimizes customer impact and can allow for improved coordination with business and residential customers to support applicable repairs.

Shift from Tier-Based to Risk-Based Inspection Cycles

Following three years of annual overhead inspections in Tier 3 and a 3-year cycle in Tier 2 from 2019-2022, PG&E elected to shift to risk-based inspection cycles starting in 2023. PG&E's

[18] A group independent from the initial inspection group.

analysis showed there was a wide range of risk for structures in Tiers 2 and 3, and that shifting to a strategy based on wildfire consequence prioritization would enable targeted inspections on higher consequence structures resulting in an increase in 'eyes on risk'. PG&E also noted that this shift allowed for better coordination with patrols, improved efficiencies, and fewer additional visits to customers.

Under the risk-based inspection plan using the WFC v3 model, plat maps used for inspection work planning with wildfire consequence scores for its structures categorized as Extreme (plat maps >99th percentile) and Severe (98th to 99th percentile) would receive inspections every year, those categorized as High (90th to 98th percentile) would receive inspections every other year, and those categorized as Medium (80th to 90th percentile) and Low (<80th percentile) would receive inspections every three years. In addition, structures in the top 10% of risk in the WDRM v3 would also be added to an inspection plan if the plat map was not already included in that year's inspection plan. Under this risk-based inspection plan, although the inspection count was reduced from approximately 395,000 HFTD/HFRA structures in 2022 to approximately 230,000 structures in 2023, the eyes on risk was increased to 64% in 2023, up from 55% in 2022. For 2024, PG&E intends to continue with this same risk-based inspection strategy, with approximately 220,000 structures scheduled for inspection.

Unlike the inspection plans in 2019-2022, which required all Tier 2 and Tier 3 inspections to be completed by July 31 of each year, the risk-based plan requires those structures categorized as Extreme and Severe to be completed by July 31, those categorized as High to be completed by September 30, and those categorized as Medium and Low to be completed by December 31. PG&E states that this was based on historical observations and learnings, which leveraged asset and wildfire risk data, external observations, System Inspections, co-worker feedback, and customer satisfaction surveys.

As depicted in Figure 9 PG&E expects the changes in the wildfire consequence scores between WFC v3 and WFC v4 described previously in this report, to result in a significant shifting of the structures currently within the 1-year and 2-year inspection cycles. PG&E indicated that using WFC v4 influenced plat maps would result in 84% of 1-year inspections changing, and 64% of 2-year inspections changing. PG&E leadership indicated that the systems inspections group, which is not subject to the longer-term planning requirements of other asset repair and system hardening programs, can be more flexible in shifting to the use of the latest wildfire risk models, and are anticipating making these changes for the start of the 2025 inspection period.

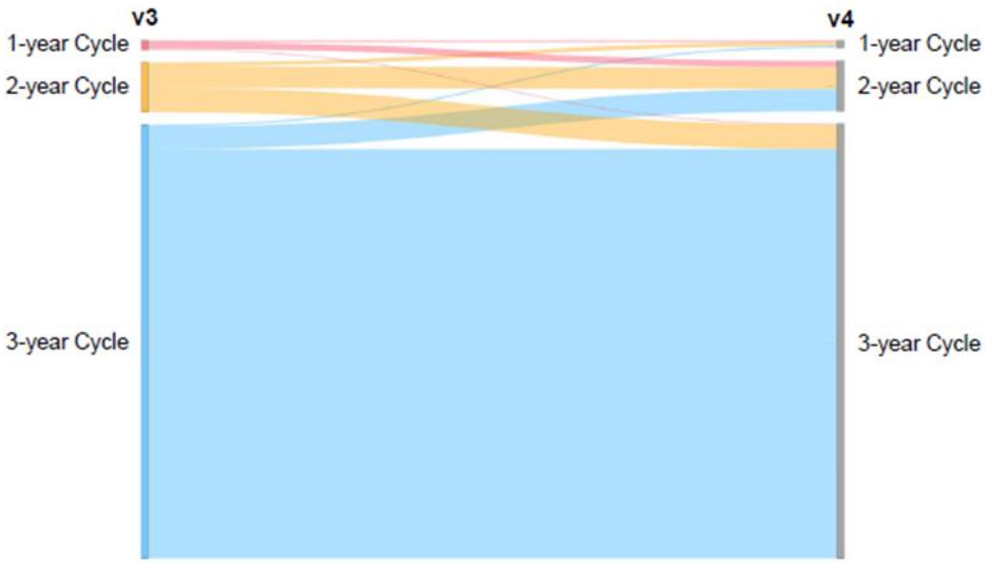


Figure 9: Inspection Cycle Shifts Between WFC v3 and WFC v4

Shift to Aerial Inspections

PG&E informed the ISM that in 2024 it intends to shift wildfire mitigation plan supported enhanced inspections that were primarily ground-based in the past, to being mostly aerial-based to gain a new vantage point of assets.

In 2023, PG&E conducted a pilot program to compare the results of side-by-side ground and aerial inspections. This pilot was conducted on approximately 12,000 poles in Extreme and Severe areas that were previously never inspected from an aerial perspective. Following this pilot program, PG&E stated that aerial inspections provided a new view of most its assets, were better at identifying conditions that correlated to actual equipment failure and were better at identifying Priority A and Priority B conditions that are challenging to see from the ground. Figure 10 provides examples of the type of equipment damage that would not have been detected in a ground inspection and that the aerial inspections can capture.

Figure 10: Examples of Defects Detectable by Aerial Inspection[19]

During the current ISM reporting period, PG&E shared its pilot study findings, the comparative tag find rate data, and PG&E's benchmarking of the use of aerial inspections among other California utilities with the ISM. The ISM reviewed the documentation provided by PG&E and held several interviews with PG&E leadership on the implementation of this shift from ground to aerial inspections. The ISM's reviews included the program mechanics, controls, and a review of the new policies and procedures relating to drone pilot operations.

PG&E performed a total of 37,000 HFTD/HFRA aerial inspections in 2023 and increased its aerial operations to perform approximately 220,000 enhanced inspections in HFTD/HFRA in 2024. PG&E's 2024 drone inspections and review of the captured imagery by PG&E's inspectors commenced at the end of January 2024. PG&E indicated that it expects the time between drone image capture and when its inspectors review the imagery to be approximately 2 days or less. It should also be noted that PG&E does not intend to cease its required GO 165 ground inspections. Under GO 165, PG&E is required to perform ground inspections every 5 years. Since the HFTD/HFRA assets have recently been inspected under 1-year (Tier 3) and 3-year (Tier 2) cycles, approximately 7,000 ground inspections will be required in 2024 to meet these regulatory requirements.

In the next ISM reporting period, the ISM intends to observe the full inspection cycle from drone capture to the desktop review of photos to the QC process reviews. As noted in the following Section, these observations will also extend to the tag cancellation process that these aerial inspections may prompt.

Inspection Effectiveness and Changes to the Inspection Checklist

During the current ISM reporting period, PG&E shared with the ISM the results of studies conducted in 2023 that examined the effectiveness of its distribution inspection programs. These studies were prompted by PG&E's observation that equipment failures had been steadily increasing in HFTD/HFRA despite an increase in inspection volumes over the same period. Per

[19] (upper left) Broken conductor strands at connector atop post insulator. (upper right) Crossarm rotting from the top. (bottom center) Crowning and rotting within the pole resulting in loose hardware.

PG&E, the average number of structures inspected in 2017 and 2018 before the start of the Wildfire Safety Inspection Program (WSIP) program was approximately 555,000 per year, versus the average over the subsequent 2019 to 2022 period of approximately 919,000 structures per year. PG&E observed that its data was showing that the ground visual inspections were generating numerous time-dependent E tags that were not effective at addressing or avoiding failures, except for certain pole and crossarm conditions.

Two other PG&E observations were that 1) a very small percentage of open E tags fail; 2) the average failure rate of structures with open E tags relative to structures without open E tags is only higher for certain pole and crossarm conditions; and 3) the likelihood of E tag failures was not higher for notifications that were open for longer periods. PG&E's conclusion was that generating lower priority notifications that may not be necessary to prevent failure creates unnecessary work and contributes to a tag backlog volume that makes prioritization challenging. Further information on the growing tag backlog is included later in this Q1 2024 ISM Report.

In order to address these issues, PG&E determined that changes were needed to its inspection process, focusing more on identifying those conditions more closely associated with failure risk. As seen in Figure 11, 97% of the equipment failures over the prior five-year period came from eight equipment types.

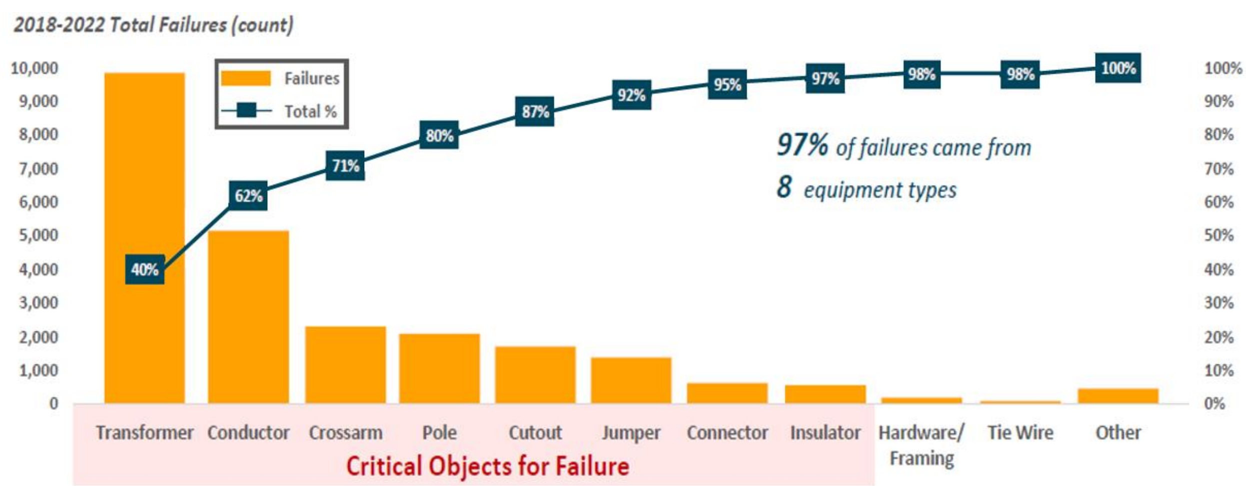


Figure 11: Asset Failures by Equipment Type[20]

To focus its inspections more on these higher risk assets, PG&E is modifying its inspector check list for 2024, simplifying its 100+ checklist down to 21 more failure specific inspection questions, the core of which are:

1. Is the pole damaged, broken, rotten, cracked outside what would be considered normal, leaning beyond 10%, or needing to be identified for any other reason?
2. Are there any compelling abnormal cross arm conditions or insulator/cutout

[20] Failures include "Equipment Failed", "Pole Rotten", "Unknown" and/or "Other" as the cause of failure. Vegetation, third party or other similar failure causes are not included.

conditions?
3. Are there any compelling abnormal conductor conditions midspan to midspan or from the point of attachment to service termination point/weatherhead?
4. Are there any compelling abnormal transformer/equipment conditions?
5. Are there any other compelling abnormal conditions or progression of known conditions to document?

During PG&E committee meetings to approve these new checklists, the ISM observed that questions were raised from members regarding possible inspection misses resulting from not listing every failure mode for every component, and not asking inspectors to positively confirm that components are okay. To address these issues, PG&E leadership noted that more questions did not necessarily mean higher quality, since in 2023 the company had a ~95% quality pass rate, which was higher than the previous year, when even more questions were on the checklist and that previous years' high question volumes led to some unintended confusion. To help mitigate concerns further, the following actions were also noted:

- Increased reliance on internal inspection resources that are Journeyman Linemen
- Robust quality review process with feedback mechanism to inspections
- Inspect App improvements to make guidance more accessible
- Improved objective guidance for many common conditions

The ISM will continue to review the new checklist and, as part of its review of the new aerial inspection procedures, observe how the inspectors utilize the checklist when reviewing drone captured images.

Pole Test and Treat Inspections

Pole Test & Treat (PT&T) is a PG&E pole inspection program that involves inspecting wood poles to test their structural integrity and treating the poles to increase their longevity. Utility poles can be inspected using various methods which may include climbing, using specialized equipment such as using sound waves to detect internal decay, and resistance testing to assess the pole's ability to withstand load-bearing stress. If issues are identified, the inspector may treat the pole or recommend reinforcement or replacement.

PG&E initially conducts a sound test on poles, probing quadrants below ground to determine if any hollow areas may exist, and to guide subsequent intrusive drill testing. Following the sound test, PG&E drills a hole into the pole to facilitate an intrusive inspection. Prior to intrusive testing, PG&E excavates the ground around the pole, and then one hole is drilled at 12" above ground, one at ground level and one 12" below ground level.

During the current ISM reporting period, the ISM observed that PG&E is also introducing a new drilling technology to supplement the regular intrusive pole testing. This new drill generates a much smaller 1/16", non-damaging hole that measures resistance, with one hole drilled above ground and three holes, 120-degree apart, drilled at angles that penetrate the pole below ground level. PG&E states that this new drill technology correlated well with PT&T with excavation, has less subjectivity than PT&T (since the drill generates a relative strength percentage that is formula based), and provides a more complete picture of pole health below ground level.

While GO 165 mandates a 20-year testing and treatment cycle for poles, PG&E historically employed a 10-year cycle within its service territory. Following the commencement of the WSIP program in 2019, PG&E noted that the reallocation of funding to other wildfire mitigation programs caused the PT&T cycle to slip from its 10-year cycle, but has indicated that it indents to revert back to performing PT&T on a 10-year cycle after this year. PG&E also considers off-cycle inspections when its Pole Rot Model flags poles for more frequent inspection. This Pole Rot Model incorporates a pole's age, wind exposure, and other environmental conditions to simulate the degradation process of poles over time.

PG&E has approximately 2.1 million wooden distribution poles across its service territory. Over a six-year span concluding in 2023, approximately 700,000 non-HFTD poles and 270,000 HFTD poles underwent PT&T. Over this six-year period the PT&T identified the following:

- 85.5% of the non-HFTD and 76.7% of the HFTD poles did not require any follow-up;
- 3% of the non-HFTD and 3.2% of the HFTD poles necessitated pole replacement; and
- 4.6% of the non-HFTD and 14.5% of the HFTD poles required pole reinforcement.

Of the remainder of the poles scheduled for testing, 5.5% were deemed unsuitable for PT&T due to various factors such as non-existence in the field, composition other than wood (e.g., concrete, fiberglass, steel), or ownership by customers rather than PG&E.[21]

Quality Assurance / Quality Control Programs

2022 Inspector Performance Observations

As detailed earlier in this Q1 2024 ISM Report, PG&E performed its HFTD inspections during 2022 on Tier-based cycles and had a WMP commitment to complete all HFTD inspections by July 31. Due to a delayed start in the year as contractor skills assessments were supported for its inspections versus the prior 3-year period for various operational reasons, PG&E was required to undertake a large number of inspections during July 2022 to meet its WMP commitment. This July 2022 increase is depicted in Figure 12. PG&E anticipated using only one contracting company during the year; however, given the volume of inspections required to be completed that month, PG&E was required to utilize a staff augmentation company and additional contract inspectors in order to meet the WMP commitment's deadline. Given that this was the highest monthly count of inspections that PG&E experienced in HFTD, the ISM undertook an analysis to review the inspection performance during this period.

[21] There is a small percentage of PT&T which have access issues including "No access", "Customer Refusal" and "Blocked Access".

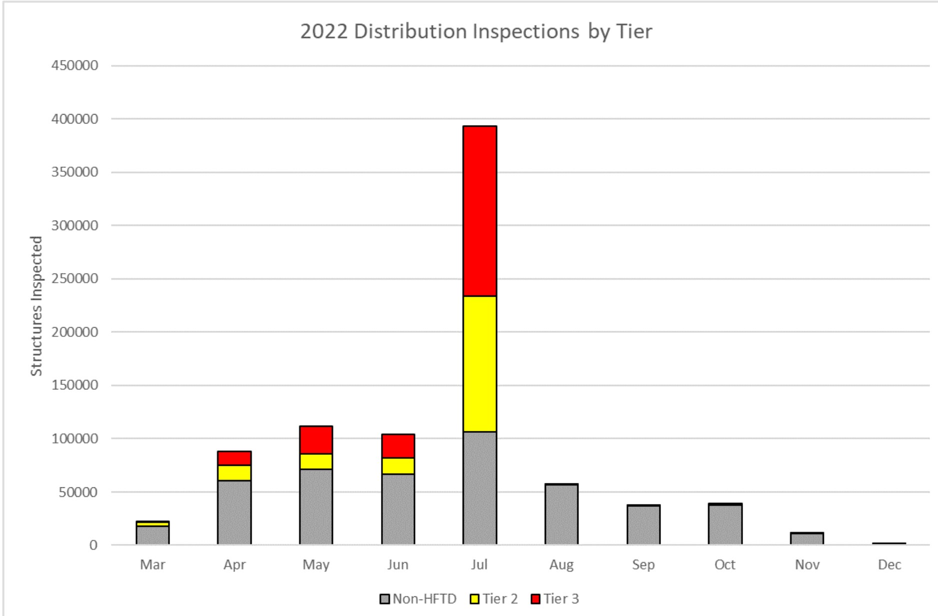


Figure 12: 2022 Distribution Inspections by Tier

The ISM observed that several of the contract inspectors worked every day during the month, and that many of the contractors were occasionally conducting over 100 inspections per day. During interviews with the ISM, and in materials presented to PG&E leadership, PG&E noted that the average time to complete an individual inspection was expected to be between 20-35 minutes. During the month of July, while the highest volume PG&E employee performed approximately 1,300 inspections, over 50 contractors were found to have higher monthly inspection counts, with the top five inspectors by volume having counts between 1,700 and 2,200. For comparison, the average high monthly count of the other April to November periods in 2022 was just over 800. PG&E has noted that inspectors could have higher inspection rate days due to flatter terrain and lower trafficked roads as well as stretches that have less equipment on poles.

In order to review the performance of the high-volume inspectors during this July 2022 period, the ISM reviewed how the defect tag find rates of the top five inspectors by July volume compared against the average of all 495 inspectors who performed inspections that month. Since all five of these top volume inspectors were inspecting predominantly in the HFTD, the comparison was made against inspectors who were also inspecting in the HFTD. The reason for using this subset is that tag find rates in HFTD were historically lower than in non-HFTD areas, since the HFTD areas were inspected more frequently over the prior years and have more overhead system hardening completed.

The ISM observed that all five inspectors had tag find rates across all tag priorities well below the HFTD averages, with aggregate tag find rates ranging from approximately 20% to 50% of the average for July 2022. None of the five inspectors identified any A tag conditions during their aggregate 10,000 inspections, and B tag find rates among these five inspectors ranged from 5% to 37% of the July 2022 average B tag find rates in HFTD. The ISM observed that these five inspectors were operating in several different areas in the HFTD, and that several of these areas have not yet received any subsequent inspections since July 2022.

In discussing these observations with PG&E leadership, PG&E informed the ISM that these conditions were flagged internally, and several steps have since been taken to avoid similar situations. One of these steps is changing the inspection plans to risk-based cycles. As outlined earlier in this Q1 2024 ISM Report, the new cycles increase the eyes on risk, while simultaneously reducing the volume of annual inspections. PG&E has noted that tactically spreading out the inspections based on risk level with the July 31, September 30, and December 31 interim deadlines for various risk categories, and reducing the number of annual inspections, allows for a smaller inspection workforce comprised of a higher percentage of employee inspectors. As shown in Figure 13, the monthly inspection counts in 2023 were smoothed out versus the prior year and contained a peak month of approximately 71,000 inspections in 2023, versus approximately 393,000 noted in July 2022.

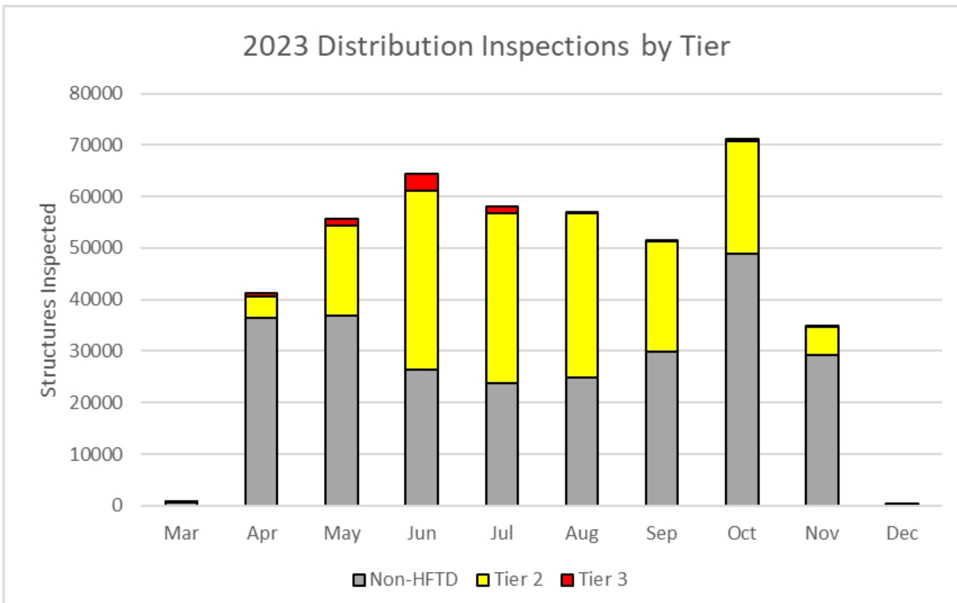


Figure 13: 2023 Distribution Inspections by Tier

PG&E leadership also noted that it developed and implemented an expanded quality control program in 2023 designed to audit individual inspector performance more rigorously. Additional information on this updated program is found later in this Section.

ISM Field Observations

During the current ISM reporting period, the ISM conducted two weeks of targeted distribution field inspections. The ISM selected the distribution inspection locations based on areas which had high ignition and outage rates from equipment failures over the prior 5-year period, as well as targeting areas that experienced higher than average daily inspection counts as detailed in the previous section and lower than average tag find rates.

The findings from the ISM's targeted inspection indicated that most of the facilities in the area were replaced or repaired in the last 1 to 5 years, with numerous pole replacements, and minimal significant damage. Various areas within this circuit were inspected, revealing replaced or repaired poles/crossarms in different locations. However, a few issues were observed, including splices on many spans, small primary wire sizes, old tree wire, and a significant amount of vegetation.

While the newer equipment may account for the lower find rate experienced by these July 2022 inspectors, the challenging terrain, hilly landscapes, heavy traffic, narrow one-way roads, and numerous secondary services and equipment on the poles, observed by the ISM would present challenges to achieving the daily inspection counts seen in July 2022 on these same circuits.

Considering the elevated frequency of historical ignitions and non-storm related outages, the ISM observed fewer high-risk issues than anticipated in the targeted area inspected. During the ISM's review some minor issues were identified but no immediate hazards related to the equipment or poles were observed.

QA/QC Program Overview and Trends

In 2022, PG&E lacked a defined quality control process following distribution inspections, contributing to a delayed feedback loop for the system inspections team and hindering the timely correction of inspector errors. As reported in ISM Report 2, the ISM's field observations from PG&E's 2022 inspections resulted in 20% of poles having at least one observation not identified by PG&E's inspection team. At the time, this was consistent with PG&E's internal quality review team.

In 2023, PG&E introduced a comprehensive quality plan, incorporating a two-tiered approach: quality control (QC) and quality assurance (QA). The QC process aimed to ensure projects met quality and compliance standards, striving to inspect 100% of HFTD assets. By year-end, PG&E completed field assessments on approximately 40,000 assets, while approximately 190,000 assets were reviewed via desktop assessments. The ISM observed that in 2023, the QC pass rates for desktop and field reviews were 93.67% and 86.11%, respectively. The top find from PG&E's QC team was identified as "*pole broken, damaged, burnt, deformed, corroded, gunshot, or showing signs of cracking, rotten or decay.*" The ISM was informed that these findings from the QC team are reviewed with PG&E's execution stakeholders on a recurring basis to highlight focus areas and learning opportunities.

Field reviews of PG&E's 2023 distribution inspections were conducted by FEP, observing over 2,500 poles. These observations resulted in a total find rate of approximately 15%. As part of the 2023 field reviews, FEP observed a notable decrease in conductor-related finds from 2022 to 2023, however there was a consistent rate of structure-related finds over the same period. A find is when FEP identifies a missed observation by a PG&E inspector.

In 2022, FEP found one fifth of PG&E's missing observations were related to "*conductor with splices tied in proximity to insulator preventing free movement of splice*". In 2023, PG&E provided additional clarity to this observation by modifying its job aid with revised information and additional inspector training. This contributed to conductor-related finds dropping to only 6% of the total share of observations made by FEP in 2023. Conversely, assets with pole damage continues to be a top find for the ISM's field team, which matches the finds from PG&E's QC team. See Comprehensive Pole Inspection Program section of this Q1 2024 ISM Report for more information.

The QA, or quality verification in 2023 was conducted upon completion of inspections and QC to identify any overlooked hazards or critical failures. Where QC aims to ensure the quality requirements are met close to real time, the QA process is designed to provide guidance to the QC methods and controls in a risk and compliance-informed approach. The quality verification was conducted on approximately 5,000 poles with an overall QA pass rate of 92.88%.

In 2023, PG&E instituted a two-week feedback loop with the implementation of the quality plan to hold inspectors accountable and promptly address any training discrepancies or knowledge errors. Building on these changes from 2023, PG&E has indicated that it plans to further expedite its feedback loop, reducing the feedback loop time to one week in 2024.

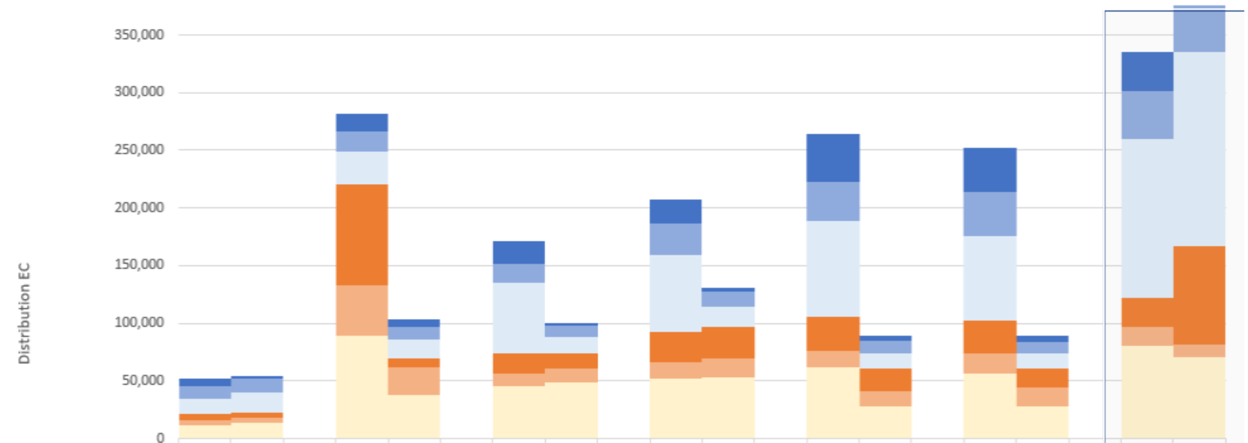
DISTRIBUTION INFRASTRUCTURE ASSET REPAIRS

Repair Tag Backlog and Reduction

In 2019, PG&E began the Wildfire Safety Inspection Program (WSIP) to proactively expand inspections of poles and associated equipment in HFTD/HFRA areas on an accelerated and enhanced basis to mitigate ignition risk. For the first year of the WSIP program, PG&E elected to inspect 100% of its assets in the HFTD/HFRA area, which resulted in large increases in both the number of inspections, and the number of new defect repair tags being created. As was described earlier in this Q1 2024 ISM Report, from 2020 to 2022, PG&E elected to continue to inspect 100% of Tier 3 assets annually and started inspecting Tier 2 assets on a 3-year cycle. It was also noted that these Tier-based cycles were replaced by risk-based inspection cycles. This change resulted in the annual inspection count decreasing; however, the higher risk assets are still inspected on 1, 2, and 3-year cycles depending on their risk scores.

Figure 14 shows that prior to 2019, the repair tag creation and completion rates were similar. Starting in 2019, PG&E increased the volume of inspections, resulting in the repair tag creations exceeding those completed for each of the next 5 years. PG&E also decreased the closed tag volume between 2021 and 2022. PG&E informed the ISM that the repair expenditure amount remained roughly the same between the two periods and is generally set during rate case proceedings. PG&E stated that from 2019 to 2021 it initially focused its backlog clearance on higher-risk, lower-cost, non-pole repairs. Further, PG&E stated that in 2022, the backlog clearance risk shifted more toward higher-cost pole replacements that take more labor resources to perform, leading to the drop in closed tag volumes. PG&E also indicated that supply chain issues impacted the tag clearance rates during the Covid-19 pandemic, but noted that these issues are resolved. PG&E stated that the speed with which annual repair work can be conducted is now primarily constrained by availability of risk-allocated capital among the wildfire mitigations.

As seen in Figure 14, there were approximately 820,000 open tags at the end of 2023 (290,000 in HFTD), with approximately 59% of these past their original tag priority repair due date (57% in HFTD).



	2018 Created	2018 Closed	2019 Created	2019 Closed	2020 Created	2020 Closed	2021 Created	2021 Closed	2022 Created	2022 Closed	2023 Created	2023 Closed	Pending-Due in Future	Pending-Late
Grand total	51,842	54,131	281,376	103,211	171,291	100,529	207,465	130,737	264,397	89,312	252,216	89,504	335,107	488,211
Non-HFTD/Non-HFRAPole	6,062	1,965	14,876	5,975	19,448	2,932	21,442	3,533	41,361	4,875	38,191	5,665	33,595	85,458
Non-HFTD/Non-HFRACap	11,706	12,543	17,511	10,805	16,802	9,224	26,757	13,332	34,778	10,990	38,698	9,765	41,327	67,110
Non-HFTD/Non-HFRAExp	12,962	17,563	28,381	16,605	61,239	14,955	66,829	16,891	82,444	12,547	73,495	13,842	138,019	169,215
HFTD/HFRAPole	5,645	3,790	87,762	8,029	17,654	12,979	26,560	27,821	29,208	19,782	28,406	15,599	25,297	84,840
HFTD/HFRACap	4,361	4,700	43,808	23,902	11,195	11,678	13,494	16,125	15,000	12,638	16,997	16,560	15,959	11,354
HFTD/HFRAExp	11,106	13,570	89,038	37,895	44,953	48,761	52,383	53,035	61,606	28,480	56,466	28,251	80,910	70,234

Figure 14: Distribution Repair Tag History (2018-2023)

As previously described, each tag is given a priority rating, which sets the amount of time in which the repair is to be completed. In Figure 14 the reference to "Pending Not Late" refers to tags which still have time remaining before they are required to be repaired in accordance with their originally assigned tag priority. Those listed as "Pending Late" are currently in the backlog and have exceeded their original tag due dates. Of the approximately 365,000 tags identified as "Pending Late", approximately 77% are priority E tags, 21% are priority F tags, the other 2% are priority A and B tags. These tags represent conditions considered to have a perceived moderate (E tag) or low (F tag) potential safety or reliability impact.

The 2023-2025 WMP contains details on how PG&E intends to clear this backlog over time, while simultaneously committing to clearing newly created tags within the original tag priority deadlines. Under its original plan, within the HTFD and HFRA areas, PG&E intended to clear its backlog of non-pole ignition-risk tags by 2025, ignition-risk pole tags by 2029, and non-ignition-risk tags by 2032. Under this original plan, each risk tag was given a risk score, and PG&E indicated it would reduce the total tag backlog risk by a set cumulative amount each year (e.g. 48% in 2023, 68% in 2024, 77% in 2025). After further study, PG&E concluded it could eliminate the backlog more quickly by bundling the tag repair work into more geographically concentrated work areas.

By bundling tag repair work by individual isolation zones, PG&E noted that this would 1) reduce the average age of an open tag by addressing more of the older tags sooner than under the original plan, 2) improve operational efficiencies with improved equipment allocations and coordinated permitting, 3) result in better coordination of asset maintenance teams with other lines of business to complete all work at one time, and 4) result in less net disruptions to customers. The ISM observed that while this bundling will result in some higher-risk ignition-risk tags being completed later than originally planned, and some lower-risk, non-ignition tags being closed sooner, the net impact of this revised plan is that all backlog tags are expected to be cleared five years sooner (2027 versus 2032). PG&E established and demonstrated to the ISM a system designed to review each isolation zone, review the tags on each zone, and calculate the risk reduction per dollar of repair cost within each zone. In order to continue to perform the work in a risk-informed manner, the isolation zones being selected for work each year are based upon the order of this risk reduction/cost ranking.

For 2024, PG&E's prioritization plan is to first clear any HFTD B tags, then clear Non-HFTD B tags, then undertake the bundled and prioritized work by isolation zone as described above.

As was discussed earlier, risk model updates have resulted in changes to the risk ranking between WDRM v3 and WDRM v4. Figure 15 shows the maintenance tag risk prioritization changes between the two versions.

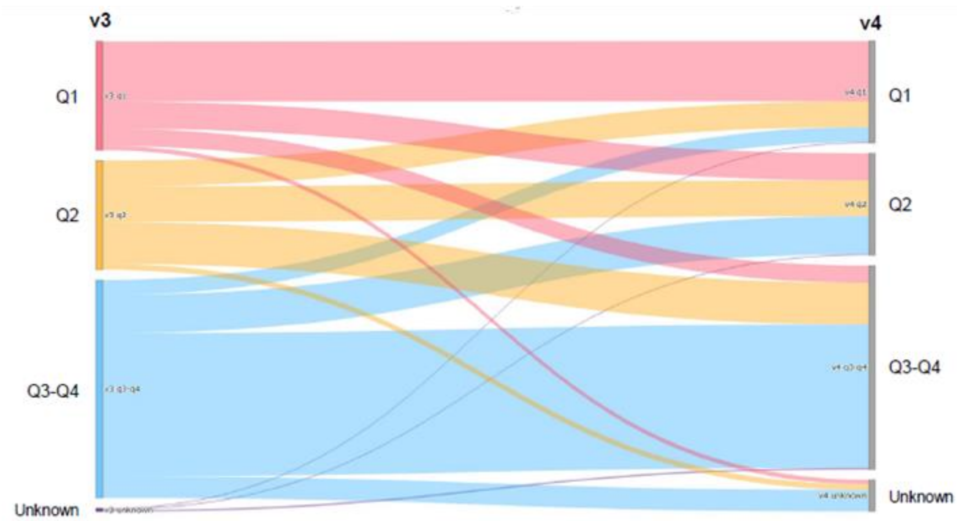


Figure 15: Maintenance Tag Prioritization Changes from WDRM v3 to v4

Although there is movement between the various quartiles, the ISM observed that WDRM v4 captures more overall risk with the additional assets being modeled (5 asset types in WDRM v3, and 10 asset types in WDRM v4), with the net result that fewer tags must be worked to reduce the same percentage of risk.[22] As of the date of this report, PG&E indicated that it has not yet determined what impact this new risk ranking may have on the bundling prioritization, and given the long lead time associated with repair work planning, when any such changes may take place. However, PG&E did indicate that it would look at some of the outliers and see where they are located within the longer-term bundling plan.[23]

As previously noted in this Q1 2024 ISM Report, PG&E elected to change its system inspections checklists for use in 2024 to better focus on identifying defects that are more strongly correlated to historical ignitions. PG&E informed the ISM that such a shift in focus will also help reduce the number of newly created, lower-risk repair tags that have been building up in the

[22] 80% of risk can be addressed with 11,900 tags in WDRM v4 versus 13,400 tags in WDRM v3.

[23] One such outlier is those that rose from the bottom quartiles in WDRM v3 to the top quartile in WDRM v4.

tag backlog. The ISM reviewed the make-up of the open tags in HFTD/HFRA and found that 78% of the tags were designated to have ignition risk. Examples of the 22% of open tags (~56k tags) that do not have ignition risk include missing High Voltage signs, visibility strips, etc. Of the 72 types of open tag repair conditions, approximately 56% were for repair work on the top 4 assets that experienced failures during the 2018-2022 period (transformers: 0.5%, conductors: 7.6%, cross-arms: 2.5% and poles: 56.4%). Other higher volume, lower failure assets include connectors, anchors, insulators, missing/damaged guy wires, and hardware/framing.

Repair Tag Reassessment

After further data analysis, pilot studies, and industry benchmarking, PG&E determined that a substantial number of the tags in its backlog relating to pole replacements and reinforcements needed systematic reassessment. The following two reassessment programs were developed and are being readied for 2024 implementation. During the next ISM reporting period, the ISM intends to perform reviews of each step in PG&E's reevaluation process and select individual pole tag cancellations for observation.

Comprehensive Pole Inspection Program

During the ISM Report 2 reporting period, the ISM conducted field observations of poles previously inspected by PG&E's distribution inspection team. In ISM Report 2, the ISM reported that approximately 20% of the structures observed in the field by the ISM had at least one observation that was not identified by PG&E's distribution inspection team. Approximately 3% of the observations identified by the ISM, but not identified by PG&E, were related to poles being broken, damaged, burnt, deformed, corroded, or showing signs of cracking, rotting, or decay. In 2023, the ISM continued to observe PG&E's distribution inspections, discovering damaged poles not identified by PG&E's distribution inspection team approximately 3% of the time. Discussions with PG&E revealed ongoing challenges in addressing subjectivity when determining pole damage levels, which the company aims to improve through training and additional descriptions in job aids.

By the end of 2023, PG&E had approximately 276,000 outstanding pole notifications, with approximately 118,000 of these in the HFTD. Some of these repair tags were past their required repair or replacement date by over 3 years. To address this backlog, and to determine if the original subjective inspection determinations were valid, PG&E proposed a new Comprehensive Pole Inspection (CPI) program. The CPI involves aerial inspections to provide additional information about the pole damage. As previously noted in this Q1 2024 ISM Report, PG&E indicated that some pole top and equipment conditions can be challenging to identify from a ground perspective. Figure 16 provides an example of a Priority E tag that PG&E reassessed and canceled following a new aerial inspection. In the photo on the left, PG&E noted the top of the structure, as seen from the ground, appears split. However, from the air, PG&E noted that the photo on the right shows that the crack does not penetrate deeply into the pole. Therefore, upon reassessment, PG&E recommended the tag for cancellation.

Figure 16: Aerial Cancellation of Ground Finding E Tag

Aerial inspections can also result in an increased tag priority. In Figure 17, PG&E's original ground-based inspection assigned a Priority B tag to this pole damage. However, the aerial inspection showed much more pole damage (as seen in the photo on the right). Accordingly, PG&E upgraded the tag to a priority A tag for emergency repair.

Figure 17: Aerial Cancellation of Ground Finding B Tag and Upgraded to an A Tag

PG&E noted that if damage is confirmed with the new aerial inspection, PG&E proceeds with pole replacement; otherwise, an intrusive inspection is performed to assess the pole's interior health and strength. An intrusive test "pass" results in the notification being cancelled, while a test failure leads to pole replacement or reinforcement, depending on the damage level.

As noted previously, PG&E conducted pilot testing to confirm the effectiveness of aerial inspections, and several tag priority changes were made as a result of that 12k pole program. In addition, PG&E also conducted a CPI pilot where 143 poles with varying types of pole damage were given both an aerial inspection and a pole test and treat. In this test, 66% of the E tags kept their original priority, 24% were cancelled, 6% were escalated to non-pole B tags, 2.1% were escalated to pole B tags, 1.4% were escalated to A tags, and 1% were flagged for pole reinforcement to provide additional strength near the base of the pole to extend the life of the asset.

CPI testing began in late 2023, and PG&E stated that it expects to perform CPI testing on approximately 61,000 poles with backlog tags, with an estimated 15,000 of these poles also expected to require the supplemental pole test and treat inspections.

Cellon Treated Pole Reassessment Criteria

PG&E's distribution and transmission wood poles are treated using a variety of chemicals, including creosote, penta, and cellon. Following the failure of a cellon-treated pole in a residential area in 2020, PG&E initiated a supplemental inspection program on its cellon-treated poles. This program began using pole replacement/reinforcement criteria that detailed the amount of excavation required around the pole for testing and certain minimum thresholds for determining pole strength that were more restrictive than its current pole testing standards. Although cellon-treated poles have not been installed since 1989, PG&E has approximately 540k cellon-treated poles in service, representing approximately 23% of all wood poles.

PG&E then began an inspection program prioritized by wood strength calculations plus wildfire risk consequence scores. During 2022 and the first half of 2023, approximately 177,000 poles were inspected using PG&E's more restrictive evaluation criteria which resulted in approximately 57,500 poles (i.e., 32%) flagged for replacement or reinforcement. This 32% rejection rate compares with a normal inspection cycle that rejects approximately 3.5% of the poles, with 50% recommended for replacement and 50% for reinforcement.

Given these higher rejection rates, PG&E benchmarked its cellon-treated pole inspection criteria against those used by other large California utilities in 2023. PG&E determined that its evaluation criteria were the most conservative. During the 2022/2023 reinspection period, PG&E completed entering data associated with all of its treated poles into its Foundry data platform for the first time. PG&E then conducted a comparative analysis in 2023 across all of its treated poles, and PG&E concluded that the failure rate of its cellon-treated poles (0.082%) was actually lower than those using penta (0.091%) and creosote (0.093%). PG&E has now elected to return to treating all poles equally with respect to internal decay rejection criteria. This shift will result in the majority of the poles flagged for reinforcement or replacement under the less restrictive evaluation criteria to no longer require this work.

Controls Over the Cancellation Process

During the ISM's review of PG&E's tag reassessment programs, the ISM discussed the controls in effect to oversee these programs with PG&E leadership. PG&E leadership indicated that all tags recommended for cancellation by an inspector must subsequently be reviewed by an IRS. While the IRSs have historically been contractors, PG&E has indicated that with the shift to mostly aerial inspections in 2024, additional employees will be available from ground inspections, so the IRS group will be comprised of all internal staff in 2024. Prior to any cancellation, the inspectors must review whether the tag has any notations for any other repair work; and tags cannot be fully cancelled unless all notations on the tag have been cancelled. PG&E also noted that inspectors can only recommend a tag cancellation, not actually cancel a tag. The administrative activity of tag cancellation must be carried out by the tag job owner and/or the Centralized Inspection Review Team (CIRT) who will check for sufficient documentation, including aerial and intrusive inspection reports as applicable.

VEGETATION MANAGEMENT OBSERVATIONS

Vegetation Management (VM) Program Descriptions and Updates

Routine

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

PG&E's DVMP Utility Standard TD-7102S indicates that during the annual Inspection Cycle, vegetation is inspected for adherence to the regulatory requirements; and as necessary, recommendations related to vegetation maintenance work are identified to ensure that vegetation remains in compliance.

PG&E's DVMP Utility Standard TD-7102S indicates that the annual Work Cycle is typically planned and patrolled with an approximately six-month offset from the annual Inspection Cycle, termed Second Patrol, i.e., the work is typically performed within one year after being identified.[24] This timing can vary due to operational or external factors. During the annual Work Cycle, PG&E's VM crews (internal and external) are expected to perform vegetation pruning and felling of trees to ensure compliance with the regulatory requirements, PG&E requirements and guidelines, and recommendations noted during the annual Inspection Cycle.

During the previous ISM reporting period, PG&E's VM leadership indicated that beginning in the 2024 annual Inspection Cycle, unless a constraint or external factor is documented, vegetation maintenance work shall be completed within one year of identification for all VM programs. Prior to 2024, PG&E did not have an internal time period for completion of identified VM prescriptions.

During the current ISM reporting period, PG&E's VM leadership also indicated that tree crew contractors are expected to notify their supervisor of field conditions that may require additional maintenance (e.g., additional vegetation points requiring maintenance, unexpected tree conditions, or other vegetation issues identified at the time of being on site). This process is not formally identified in PG&E internal VM documents or procedures. The supervisor is

[24] When tree work is identified during the Inspection Cycle, PG&E uses a prioritization process to identify if any work needs to be performed sooner (such as removal of a particularly hazardous tree) and will address it sooner if required.

responsible for notifying PG&E; therefore, the identified work can be scheduled/completed. In the current ISM reporting period, the ISM identified one instance where it appears that PG&E did not follow this process, as shown in Figure 18. PG&E, or PG&E's contractors, pruned branches from a hazard tree with a large area of decay approximately 20 feet off the ground. The hazard tree was likely difficult to see while performing a typical routine inspection but should have been identified by tree workers based on PG&E's expectation. One data point is not enough to extrapolate if this is a widespread issue, but the ISM will continue to look for similar instances during field inspections.

Figure 18: Example of the hazard tree with a large area of decay

Further, PG&E's VM leadership indicated that in an effort to minimize touch points with customers/landowners, implement a more efficient approach to VM activities, and reduce VM related costs, in 2024, PG&E will overlap the Routine VM activities with other VM program activities as much as feasible.

The ISM will continue to monitor and analyze PG&E's VM activities and the impacts of the related changes.

Vegetation Management for Operational Mitigation (VMOM)

As reported in ISM Previous Reports, VMOM is one of the three replacement programs succeeding PG&E 's Enhanced Vegetation Management (EVM) program. PG&E's VM leadership indicated that VMOM is slated to address 6,500 trees on EPSS-capable circuits, encompassing both proactive measures and carry-over work from 2023. These VMOM activities will target circuits with heightened outage occurrences from EPSS and entails "proactively" inspecting 700 miles under the "Proactive" VMOM program. 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. The scope of work for Proactive Projects is determined by the tree failure history for the circuit. Additionally, 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. Field personnel will retain the discretion to extend the inspection beyond 5 spans if deemed necessary. PG&E's VM leadership noted that not all post-inspections are conducted by an ISA Certified Arborist or an ISA TRAQ credentialed Arborist, typically an "arborist" or an experienced utility personnel will conduct the investigation.

Tree Removal Inventory (TRI)

As reported in ISM Previous Reports, the TRI focuses on trees which were previously assessed using the PG&E's Tree Assessment Tool (TAT) or during EVM inspections prior to the use of TAT. During the current ISM reporting period, the ISM reviewed PG&E documentation that noted in 2023 PG&E inspected approximately 88,000 trees under the TRI program out of the almost 400,000[25] trees for potential mitigation. In the current ISM reporting period 35,000 trees out of the 88,000 have been mitigated and the remainder 53,000 trees were mitigated under another VM program, the conductor no longer exists, or no tree work required/needed.

Further, the documentation identified that each year the TRI program has a targeted mitigation rate. PG&E documentation indicated a 2023 target of 15,000 trees; and that PG&E exceeded this target by over 20,000 trees due to some of the trees already being abated in the field or from the trees no longer having strike potential due to the relocation of the facility. PG&E's target for 2024 is to mitigate 20,000 trees which includes trees mitigated 1) by the TRI program, 2) by another PG&E VM program such that the tree is no longer present, or 3) because the tree no longer poses a threat to PG&E facilities because the facility has been relocated. The 20,000 trees identified for 2024 were identified from a population of approximately 101,000 trees prioritized across 225 Circuit Protection Zones based on the WDRM v3 Trunk Model.

PG&E has 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. However, if the TAT Tool assessment has a result other than Abate, the tree will be re-inspected by an ISA Tree Risk Assessment Qualification (TRAQ) qualified inspector.

Focused Tree Inspections (FTI)

As reported in ISM Previous Reports, 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 including specific tree species. During the currently ISM reporting period, PG&E reported completing inspections on 267 circuit miles under the FTI program and set an inspection target of 1,500 circuit miles for completion in 2024. PG&E's VM leadership indicated that during these inspections, Level 2 assessments[26] will be

[25] At the end of the EVM program, PG&E had 385,000 trees listed for removal. A PG&E internal audit identified an additional 11,000 trees that were not included in the initial 385,000 trees.

[26] There are 3 levels of inspection associated with ISA TRAQ tree risk assessments. A Level 1 assessment is a"

performed on any tree that could strike the primary conductor.

Currently, Vegetation Management Inspectors (VMI) utilize an ISA TRAQ Form in its paper format, which is then uploaded electronically. PG&E VM leadership indicated that digitalization of the paper form is in process with an expected completion by April 1, 2024. PG&E VM leadership also indicated that the ISA TRAQ credential is a prerequisite for personnel to qualify for the FTI VMI role.

PG&E VM Training

During the current ISM reporting period, PG&E VM leadership indicated that in 2024, PG&E is conducting vegetation management training for all employees and contractors throughout the service territory. PG&E estimates that total participation will be approximately 480 internal personnel and approximately 1,200 contractor personnel. The PG&E training is a four-hour course focused on FTI, TRI, VMOM, and Constraints; routine and second patrol will also be discussed during the training as a refresher.

The training covered the main changes within the VM Distribution Inspection Procedure (DIP), and it was observed that PG&E expected all personnel attending the training to have prior knowledge and understanding of the DIP before attending.

PG&E started the training with a safety moment emphasizing the importance of a strong safety culture and building a sense of respect for each other with support of all upper management, including a video from the PG&E CEO expressing the company's attitude and commitment to safety. It was further illustrated in catchphrases such as "Start When Safe," "Stop When UnSafe," "Stop When Conditions Change." An additional topic during the safety presentation of the training pertained to all personnel having "Stop Work Authority" regardless of their tenure or experience including internal and external contracted personnel.

During the training course, most of the questions the attendees asked were about TRI trees. The training included the process of a Level 1 tree risk assessment that the VMI follows. The VMI will perform a Level 2 tree risk assessment (360°) if a tree exhibits defects or signs of decline. The Level 2 tree risk assessment utilizes arboricultural hand tools such as a sounding mallet, binoculars, soil probe, diameter tape as well as other hand tools. The training covered an overview of site conditions and tree defects that increase the likelihood of failure. These definitions are included in the California Power Line Fire Prevention Field Guide (2021).

Through regular reporting and weekly meetings between PG&E's VM Execution and Quality Management (QM) Leadership groups, all QA/QC reviews and their associated findings were reviewed and discussed. The PG&E QM Leadership group also implemented "Quality Learning Forums" with VM Execution, system wide, to discuss the granularity of reviews and findings to ensure alignment.

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.

PG&E's findings and lessons learned included 6,500 trees that "will not hold" (radial clearance) until next maintenance cycle and currently not meeting Minimum Distance Requirements, or EVM distances not being maintained. PG&E's internal QC identified 6,300 "fall in trees" that were not identified which included missed tree defects, trees with excessive lean, dead limbs, and hazard trees. Strain and abrasion on secondary conductors and guy wire strain were mentioned as a reminder to inspect conditions and report. All idle lines should be considered energized and inspected by the VMI. The most reported VMI errors included procedures not being followed, missing LAN ID, missing information in record, unable to locate, and incorrect status of Vegetation Point.

The Constraint Management Team (CMT) establishes standardized constraint resolution processes and procedures. The CMT serves as the Line of Business liaison for other PG&E partners including Environmental, Customer Outreach, as well as a support resource for Vegetation Operations. The CMT is re-branding terms from "Customer Refusal" to "Customer Interference." Attention is focused on safety and compliance, customer service, recordkeeping, and best practices. Constraints are housed in OneVM. All agencies, except Caltrans/Railroads, have a 60-day mitigation turnaround for P-1/P-2. Caltrans/Railroads have a set protocol of 90-120 days (about 4 months) to review P-1/P-2 conditions to permit work to move forward to mitigation.

ISM VM Targeted Field Inspections

In January 2024, the ISM conducted two weeks of targeted vegetation management field inspections to confirm PG&E/PG&E Contractor adherence to industry BMPs, ANSI-A300 standards, and Wood Management that are referenced in PG&Es internal documents and procedures. Selected locations were based on an analysis performed using PG&E 2022 and 2023 data, two locations with high ignition and outage rates from vegetation were selected, as well as selecting areas that incurred CPUC reportable ignitions in the past. During these targeted vegetation management inspections, the ISM also followed up on two of PG&E's Post Ignition Investigation Reports (PIIRs) (one in each Inspection Area noted in Table 1 below) and inspected ten locations where TRI work was completed (all in Inspection Area A in Table 1 below).

The ISM observed the following during the targeted vegetation management inspections:

- The inspection areas consisted of narrow corridors and horizontal construction with no covered conductor.
- Vegetation conditions on the PIIR inspections were similar in both areas, although geographically distant.
- Tree density and canopy heights in the inspection areas increased the potential of impact from broken/wind-blown branches and whole tree failures.
- No hazard trees were identified in the ten TRI tree locations inspected. The ten TRI trees did not have strike potential. One tree was mitigated as part of TRI Program, two trees had been pruned under the Routine Program, and the seven remaining trees were either under or leaning away from the conductor.
- Hazard trees, radial clearances, non-compliant wood management, and non-compliant ANSI-A300/BMPs were identified in each inspection area as summarized in Table 2.

Table 2: ISM Targeted VM Inspection Summary of Data Collection

Attribute	Inspection Area A	Inspection Area B	Total
Number of Observations (Radial Clearance, Hazard Trees)	0	4[27]	4
Wood Management non-compliant	11	8	19
ANSI-A300 non-compliant	59	63	122
Number of Level-1 Tree Inspections	1114	776	1890
Number of Spans Inspected	116	20	136

Table 2 above summarizes the observations identified during the two-week targeted vegetation management inspections.

PG&E VM Practices and Procedures

ANSI-A300/Best Management Practices

As reported in ISM Report 3, PG&E's VM Procedures include industry standards such as Integrated Vegetation Management (IVM) principles including ISA Best Management Practices (BMP) and ANSI-A300 Pruning Standards. During the current ISM reporting period, the ISM continued to observe non-compliant ANSI-A300/BMP conditions during the targeted vegetation management field inspections (as discussed in the ISM VM Targeted Field Inspections section of this Q1 2024 ISM Report), as well as, at other PG&E's service territory locations inspected by the ISM.

During the current ISM reporting period, PG&E's VM leadership indicated that ANSI-A300/BMPs are included in the tree contractors' contract language; however, PG&E's VM leadership was uncertain of the exact contract language and specific tree crew obligations. Further, VM leadership stated it is incumbent upon the vendor to determine delivery of ANSI-A300 specific instructions to the tree crews. The DVMP and DIP include instructions for the Vegetation Management Inspector; however, these documents do not address actions to be taken by tree contractors performing the work. PG&E's VM leadership indicated potential reasons for that lack of adherence to ANSI A300/BMPs; however, no corrective actions were identified to resolve the issues.

Figure 19 provides examples of non-compliant ANSI-A300/BMP pruning observed by the ISM during the current ISM reporting period's targeted inspections.

[27] Of the 4 Observations, 3 were missed hazard trees and 1 was a radial clearance violation. The radial clearance violation and 1 of the missed hazard trees were on the same vegetation point.

Figure 19: ANSI-A300/BMP non-compliant[28]

Wood Management

As reported in ISM Report 3, wood management is a PG&E BMP. PG&E's BMP states, "Woody debris created by chipping, lop and scatter, or brush mowing operations must be left at an average depth of less than 18" from ground surfaces unless otherwise specified in an easement or landowner agreement.

During the current ISM reporting period, the ISM's field observations include wood management conditions that were not compliant with PG&E's Best Management Practices Job Aid. Additionally, the ISM noted specific references within the Vegetation Point I.D. indicating the prescribed wood management activity for the site that was not performed as documented in the system of record (i.e., woody debris was prescribed to be chipped, but this work was not performed).

During the current ISM reporting period, the ISM continued to observe non-compliant wood management conditions throughout PG&E's service territory visited. In certain instances, the conditions were the result of storm damage. Per discussion with PG&E, PG&E indicated that it does not remove debris from sites generated by storm activity. PG&E stated that its intent is to repair the damage to the electric system in order to restore service.

Figure 20 and Figure 21 provide examples of non-storm related non-compliant wood management observed by the ISM during the current ISM reporting period's targeted

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[28] (left) The tree pictured on the left is a Ponderosa pine which has been repeatedly topped. This has resulted in multiple tops and weak co-dominate branch structure and promoted decay at the point of origin. (right) The tree pictured on the right is a Blue oak with improper pruning "heading" cuts at multiple locations. This type of improper pruning results in resprouting of branches that are weakly attached to the tree and are growing directly toward the conductors.

inspections. Figure 22 shows an example of compliant wood management observed by the ISM.

Figure 20: Inspection Area A: Wood Management "debris in road drainage" non-compliant (left). PIIR site with non-compliant Wood Management (right)

Figure 21: Inspection Area B: Non-compliant Wood Management

Figure 22: Inspection Area B: compliant wood management showing lopping/scattering of limb slash and disbursement of larger material

Constrained Trees

As reported in ISM Report 3, during the ISM's VM field inspections the ISM identified multiple "Constrained" trees, including hazard trees. Per discussions with PG&E and review of PG&E documentation, the ISM noted that these trees can remain in this status for more than two years for various reasons (e.g., permitting and other factors). The ISM also reported that PG&E established a "Central Constraint Team" for aiding in resolution of constraints. Further, the ISM reported that PG&E's VM leadership stated that if a Constrained tree reaches a Priority 1 (P-1) or Priority 2 (P-2) level while in the constrained status, the tree will be mitigated under the "Emergency Clause" which PG&E has established with each agency. PG&E monitors the constrained trees backlog through PG&E's VM Routine inspections (i.e., identifying change of condition).

During the current ISM reporting period, PG&E stated it has made significant progress towards creating a centralized inventory of constrained trees. In partnership with regional operational teams, the centralized constraints team created a centralized repository with data and statuses on various locations. Additionally, new procedures were introduced to standardize the approach to expedite resolution of constrained trees through collaboration with internal and external stakeholder organizations. PG&E also stated that through implementing a constraints management standard in 2024 approximately 65,000 constraints have been resolved across VM programs.

During the current ISM reporting period, the ISM held additional interviews with PG&E's VM leadership regarding Constrained trees. During this interview, PG&E's VM leadership indicated that constraint resolution timelines vary by agency and by how much work can be performed at the time of project submittal. On certain ownership, such as United States Forest Service, National Park Service, Caltrans, Coastal Commissions, , and Sierra Pacific, vegetation points are automatically determined to be "Constrained" by the VMI upon field inspection.

Further, PG&E's VM leadership indicated that efforts being taken in 2024 to address Constrained trees and the related backlog include updating constraint processes regarding encroachment and bird protection, enhancing reporting capabilities, reducing environmental permitting turnaround time, building better relationships with agencies, and improving internal/external communications.

PG&E Systems of Record

OneVM

As reported in ISM Report 3, PG&E initiated the OneVM program in March 2023 with the intention of consolidating all VM programs onto a single platform over the course of several years. During the current ISM reporting period, the ISM noted that OneVM incorporated Routine and Second Patrol, as well as the proactive segment of VMOM. PG&E leadership also indicated to the ISM that FTI is included in OneVM, with the digital TRAQ form component to be incorporated by the end of March 2024. Despite having a more stable system of record for these programs, during the current ISM reporting period the ISM observed the following OneVM implementation challenges:

- <u>Incomplete Data on OneVM</u>: OneVM has certain data inaccuracies and/or duplicative data. During the ISM's interviews with PG&E VM leadership, PG&E VM leadership acknowledged the data concerns and noted that a data Management team was created to align with Enterprise Data Management to identify Critical Data Elements and Critical Data Sets for accurate processes.

- Diverse Program Needs: The differences associated with each PG&E VM program complicates the functionality and potential user acceptance of OneVM. For example, certain tools like the Priority Tag Tool (PTT) have a long history of use across multiple departments and the PTT information needs to be accessible to all field personnel. PG&E's VM leadership indicated that PG&E plans to address the diverse program needs through a strategic approach. As part of this approach, PG&E's VM leadership noted that the intent of OneVM is to eventually have one data source for all programs used by PG&E inspectors and tree crews.
- Legacy Systems: There are existing legacy programs still in use by field crews, such as the EVM Desktop Viewer and the Work Verification for Defined Scope Map. PG&E personnel consider these systems as crucial for historical reference and maintaining established EVM clearances and viewing vegetation points and associated projects created prior to March 2023. Integrating these programs, which are used regularly in the field, directly into OneVM is an ongoing challenge.
- User Guides and Training: Feedback on user guides and training materials indicates a need for greater user-friendliness and relevance. PG&E VM leadership indicated that PG&E is actively addressing this feedback by enhancing the user guide's accessibility and streamlining training efforts. For example, in-person training sessions are now conducted for all inspectors, with plans for in-person sessions upon the introduction of new programs like FTI for those individuals that will directly interact with the new program.
- Mobile App Use: Users have provided feedback regarding the user interface of the mobile version of OneVM, highlighting areas for improvement. PG&E personnel raised concerns about the app "freezing" in the field and the need for enhanced robustness in offline mode. PG&E VM leadership acknowledged these issues and stated that PG&E is actively working on improving the interface and addressing identified data synchronization concerns.

As PG&E faced these challenges, during the current ISM reporting period, PG&E decided to reassess the rollout of the OneVM program in order to increase the efficiency and effectiveness of the program. Originally, PG&E's approach was to transition each program to OneVM individually, since each program had different requirements and needs. However, PG&E is considering a more comprehensive rollout approach (i.e., introducing multiple programs simultaneously) with many of their distribution programs expected to be incorporated into OneVM by June. This change indicates a strategic shift in their implementation strategy.

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 report is directed toward: 1) Gas Risk Model; 2) Gas Asset Data Management; 3) MAOP Program Updates; 4) ILI Program Updates; 5) Leak Management; 6) Tee Cap replacement program; and 7) Gas Quality Monitoring.

RISK MODEL

PG&E maintains risk models to comply with the US Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations and to support PG&E's Risk Assessment and Mitigation Phase (RAMP) Model. The following provides background and a discussion of gas-risk model observations.

Gas Risk Model & Enterprise Risk Model Background

As prescribed by PHMSA regulations, PG&E maintains, updates, and performs annual risk runs utilizing its Transmission Integrity Management Program (TIMP) Risk & Threat Model (R&TM). The R&TM is a tool that uses an algorithm to calculate the Risk of Failure (RoF) associated with specific pipeline segments in order to risk rank each segment. RoF is the product of Likelihood of Failure (LoF) and Consequence of Failure (CoF), each of which are calculated using a variety of inputs from PG&E records and Subject Matter Experts (SMEs). Each year, PG&E's TIMP Risk Team captures an annual snapshot of the data that comprises the RoF calculations, and PG&E's TIMP Risk Team works with the Asset Knowledge Management (AKM) Team in performing data QC to ensure the data accuracy.

PG&E has established TIMP Risk Steering Committees for each of the threat categories covered in the R&TM, which meet annually to review the appropriateness of the performance-based risk calculations associated with each threat, review annual comparisons of risk calculations, and discuss issues or proposed changes to the R&TM. The R&TM inputs are based on multiple SME team reviews to determine the appropriateness of the assumptions that go into the CoF and LoF calculations.

The R&TM results are used as inputs to PG&E's RAMP Model. The RAMP Model is required by the CPUC to inform rate making decisions, and includes safety, reliability, and financial components. The RAMP Model allows PG&E to compare risk and budgets, in terms of Risk Spend Efficiency, across its areas of business.

New Risk Model Platform Update

During the current ISM reporting period, the ISM interviewed PG&E's TIMP Risk Team regarding the 2023 update to the R&TM. The TIMP Risk Team updated the technical model infrastructure to help streamline the R&TM process and provide an ability to perform sensitivity analyses on risk scenarios designed to test the practical bounds of current annual risk assessments. It has been reported to the ISM that the new R&TM infrastructure will eventually adopt a single Geographic Information System (GIS) interface across transmission and distribution gas system components. The new platform also has the potential to integrate with Foundry™, which could streamline the process of TIMP R&TM results feeding enterprise risk calculations in future RAMP Model and rate case submissions.

PG&E indicated that it has been working with a U.S.-based risk modeling software vendor over the last three years to develop the new R&TM technical infrastructure. This vendor has developed and provides pipeline integrity management software and services to large energy transportation companies. PG&E worked with the vendor to ensure that the functionality and continuity of specific R&TM risk algorithms are available within the 2023 R&TM. PG&E stated that the new R&TM will maintain pre-2023 risk and operational logic algorithms to preserve the calculation methodology for LoF, CoF and RoF. PG&E expects the new R&TM to provide additional user input control and functionality. PG&E indicated that the 2023 R&TM was calibrated with prior 2022 R&TM input and calculation results. PG&E also indicated that the new platform is efficient, with significantly shorter run times. However, PG&E's TIMP Risk Team is working through challenges associated with data preparation and integration. PG&E plans to measure the efficiencies gained using the new platform when the 2024 Risk Model run is performed.

The input data preparation process for the 2023 R&TM continues to utilize an "annual data snapshot" performed during the calendar second quarter (Q2). PG&E's TIMP Risk Team coordinates with the AKM Team to process and QC the data to support the risk assessment across all TIMP gas system components. The results of the Q2 TIMP and AKM data QC are also used in the preparation of PG&E's PHMSA annual report.

During March and April of the calendar year, PG&E's TIMP Risk Team provides selective risk profiles to the TIMP Steering Committees for their SMEs to review. The committees vote for binding corrective actions to define continuous improvement resolutions. PG&E expects the current annual data snapshot and QC process to continue for the next several years. Upon completion of upgrades to critical data sets and additional data quality analysis, PG&E's Gas Data Asset Management Team plans to provide continual QC assessment and gas asset risk data to a new single GIS data model.

The ISM intends to continue monitoring PG&E's transition to the new R&TM. Reporting on progress will only continue should the ISM observe any material changes in status.

GAS ASSET DATA MANAGEMENT

During the current ISM reporting period, the ISM held interviews with PG&E Gas Data Asset Group. As reported in ISM Report 3, this group works to recognize gas data assets on an equivalent level of importance to physical gas assets, providing focus on the structure and implementation of gas data management and governance, and to enable more effective work execution and risk prioritization.

During the current ISM reporting period, PG&E continued the process of migrating several of its key datasets to Palantir Technologies Foundry (Foundry) data model, with a goal of completing this exercise by 2028. PG&E expects Foundry to provide all of Gas Operations with real time data that is trusted and verified across all gas assets, which can be used for a variety of data analyses. PG&E has indicated that while it is still early in the process, this goal appears to be achievable.

As part of its data quality efforts, PG&E's Gas Data Asset Group is conducting a multi-year process to certify each dataset under management by performing a QA/QC review to ensure adequate data quality. PG&E plans to eventually ingest its GIS dataset, which includes physical asset information, as well as its SAP data set that contains operational records, such as maintenance performed and leak records. Once these large datasets are ingested, other datasets will be evaluated. The QA/QC process contains 'manual' data review by PG&E employees and SMEs to ensure it meets quality standards. PG&E indicated that it is evaluating using a predictive tool to identify data quality rules and measure the quality of the data set.

PG&E's Gas Data Asset Group is working with the TIMP and DIMP teams to develop a Strategic Data Plan as a part of the implementation of Foundry. PG&E indicated that the incorporation of GIS and SAP data into Foundry is largely complete; however, the process includes continual refinement through input from its SMEs, asset family owners, data experts, and its leadership. In addition to the migration to Foundry, PG&E informed the ISM that SAP and GIS are both scheduled to undergo modernization/updating. These efforts will need to be coordinated with the Foundry migration, as well as the PG&E TIMP and DIMP teams.

The ISM intends to continue monitoring each of these data management initiatives. Reporting of activities will only continue should the ISM observe any material changes in status.

MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP) PROGRAM

During the current ISM reporting period, the ISM interviewed PG&E's MAOP team to understand operations and areas of focus. The team is fully staffed with a focus on completing MAOP confirmation activities which includes reviewing remaining pipeline features such as fittings, nipples, and valves in compliance with recent PHMSA regulatory changes.

The MAOP team is also reevaluating its MAOP reconfirmation processes in light of these changes. The following provides a discussion of PHMSA RIN2 and PG&E's MAOP reconfirmation status.

Pipeline and Hazardous Materials Safety Administration Gas Mega Rule Part 2

The PHMSA Gas Mega Rule Part 2, commonly referred to as RIN2, was adopted on May 24, 2023. RIN2 requires that all gas pipeline operators meet modified gas leak response requirements, leak repair schedules, and pipeline data risk assessment requirements. The data risk assessment requirements of RIN2 require each operator to confirm it has "Traceable, Verifiable, and Complete" (TVC) records for pipe segments or feature material properties while examining pipe anomalies or performing pipe repairs. To this end, PG&E's MAOP team reviews the technical design, materials, and strength requirements prior to installation of a feature. For existing pipeline features, PG&E's MAOP team indicated it is continuing to review technical feature documentation for MAOP confirmation of approximately 4,000 remaining pipeline features out of more than 500,000 total features.

PG&E's MAOP team performs pipeline feature reviews based on risk ranking such as high consequence areas (HCA)/moderate consequence areas (MCA) versus lower consequential locations. Additionally, PG&E's MAOP team performs feature reviews based on TIMP vs DIMP, higher versus lower operating pressure, large vs small feature diameter, feature age, and feature grade material.

When the pipeline segment or feature does not have TVC documentation, PG&E's MAOP team performs an Engineering Critical Assessment (ECA) following the criteria in federal regulations 49 CFR §192.624 and §192.632. The purpose of the ECA is to reconfirm the MAOP in lieu of pressure testing and other MAOP reconfirmation methods.

MAOP Reconfirmation

PHMSA RIN2 rule requires operators to document and reconfirm MAOP for HCA and MCA pipeline locations, subject to criteria specified in 49 CFR §192.624(a). PHMSA's MAOP reconfirmation requirements are limited to pipeline segments that lack TVC pressure test records.

PG&E initially scheduled MAOP reconfirmation pressure testing through 2035 for approximately 260 miles. However, in response to the new RIN2 requirements, PG&E initiated a 12-to-18-month effort to technically reevaluate these miles in order to determine if testing is required by the new RIN2 requirements. This reevaluation would potentially remove regulated pipe segments that PG&E initially planned to test. PG&E stated that this reevaluation may reduce the pipelines that require testing due to the RIN2-based MAOP reconfirmation requirements from 260 miles to approximately 50 miles or fewer. According to PG&E, the remaining MAOP reconfirmation pipeline quantity may be reduced because it includes segments that:

- Show a reduction in consequence of failure using RIN2's updated technical parameters,
- Operate at less than 30 percent Specified Minimum Yield Strength (SMYS) operational stress, or is considered relatively low stress pipe, or
- Can be evaluated by ILI tools precluding physical strength tests for pipe located in HCA class 3 and 4 zones. This will allow ECA in lieu of testing as explained in the following discussion.

For reconfirming MAOP, PHMSA includes an option for operators to perform an ECA in lieu of pressure testing and other reconfirmation methods. Operators choosing the ECA method for MAOP reconfirmation may perform an ILI and a technical analysis. The technical analysis must utilize acceptance criteria to establish a safety margin equivalent to that provided by a pressure test.

If an operator chooses to use ECA and ILI to determine MAOP reconfirmation but does not have one or more of the material properties necessary to perform an ECA analysis (such as diameter, wall thickness, seam type, grade, and V-notch toughness values), the operator must apply conservative assumptions and verify pipeline segment undocumented information per the requirements of 49 CFR §192.607.

The ISM intends to continue monitoring PG&E's evaluation and application of new MAOP reconfirmation requirements.

IN-LINE-INSPECTION (ILI) PROGRAM

PG&E performs routine inspections of natural gas pipelines that include cleaning and inspecting the inside of the pipe. 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 by gas pressure. When a pig gets to the designated end-point, it is trapped in a “receiver” and removed. The ISM interviewed PG&E’s ILI team regarding ILIs performed in 2023, discussed actions designed to remediate pipeline operational risk in 2024, and discussed updates to operator qualifications related to Calistoga Investigation.

Current ILI Activity and Gas System ILI Upgrade Status

During the current ISM reporting period, the ISM interviewed PG&E ILI leadership. PG&E’s ILI leadership indicated that between 40 and 50 ILI projects are performed per year. The ISM observed that PG&E’s ILI Team has currently scheduled approximately 20 ILI projects in 2024 to inspect 350 miles of pipelines. The proposed projects include a “first-time inspection” of approximately 100 miles.

ILI operations require a certain level of infrastructure in order to conduct inspections. The ISM observed that PG&E estimates approximately 50% of its system is capable of supporting ILI operations, and PG&E set a 15-year goal to increase this value to 69%. PG&E is evaluating its 2023 15-year goal to consider eliminating pipe ILI upgrades where lower consequence, low pressure, and low risk areas where appropriate.

The ISM observed that PG&E performs a gas system study every 5 years to prioritize pipe segment upgrades in support of ILI operations and associated pipeline “pigging.” PG&E reported that simple upgrades to enable ILI operations have mostly been completed, and that the remaining, more challenging, upgrade projects include:

- Low pressure lines that require special robot or tethered ILI tools;
- Inner pipe diameters that change significantly due to legacy pipe segment design, fittings, or valves;
- Acquisition of land plots to accommodate ILI tool launchers and receivers located within densely populated and expensive suburbs;
- Dramatically different pipe and fitting diameters encountered within multiple pipe borings under bodies of water, roads, or other pipe crossings; and
- Radial feed gas system configurations where upgrades may require multiple-week outages requiring relocation of customers to hotels for weeks or require community gas service support with PG&E portable CNG/LNG services.

ILI Operation Scheduling & Data Collection

Federal regulations require ILI operations to be performed on a 7-year cycle on regulated pipeline segments. PG&E schedules ILI operations on a 6-year interval to provide sufficient time to perform the inspection within the regulatory timeframe. The extra time allows PG&E to recover from instances where:

- An ILI tool becomes physically stuck during the operation and requires physical extraction from the pipe;
- ILI data capture was below PG&E SME data quality standards; and
- A special ILI tool is unavailable or must be constructed.

The extra time also provides coverage for failed ILI Tests (tool travel restrictions or erroneous data collection). Failed runs typically occur during first-time runs which have an average failure rate of approximately 10%.

PG&E performs a full review of pipe data during ILI operations, including: 1) uploading data to GIS after project completion; and 2) validating and verifying conflicts when comparing pipe tallies, line pipe seams, wall thickness, and pipe material with as-built data.

ILI Tool Vendors

PG&E contracts with two ILI tool vendors: a primary vendor and a secondary vender. The primary ILI tool vendor supports approximately 80 percent of PG&E's ILI projects and provides a variety of special ILI tool diameter ranges and instrumentation technologies. The primary vendor designed and fabricated special ILI tools to accommodate certain PG&E pipe diameters and inspection conditions. The secondary vendor performs ILI operations on pipelines that do not support typical pigging operations. The vendor provides tethered and robotic ILI tools able to inspect pipe segments up to 1,000 feet in length. The ISM observed that PG&E scheduled both ILI tool vendor companies for 2024 ILI operations.

ILI Team Staffing

During the ISM's interview, PG&E's ILI team reported being fully staffed and indicated that it will soon add another ILI engineer. PG&E's ILI team has an internal recruiting program and a college recruiting program. PG&E provides formal ILI engineer training where candidates spend time with PG&E SMEs. PG&E also provides third-party industry ILI operation training opportunities. PG&E's ILI team reported that it is also considering contracting or outsourcing technical tasks to contractors where practical.

ILI Operation Qualification

As reported in ISM Report 3, PG&E is in the process of documenting changes to ILI operation processes and safety guidelines for launching and receiving ILI tools (pigs) on PG&E in-service pipelines.

The ISM observed that several existing PG&E teams are operator qualified (OQ) to perform ILI operations including preparing and operating pig launching and receiving facilities. The OQ is based on PG&E's pipeline construction and service training, qualifications, and experience. ILI teams requiring the proper OQs are identified by their internal acronyms:

- GTGC = Gas Transmission General Construction
- TPCO = Transmission Pipeline Clearance Operations
- GPOM = Gas Pipeline Operations & Maintenance

PG&E's TPCO team is responsible for ensuring all related pipeline segments and laterals are appropriately conditioned with gas pressures and flow rates that ensure ILI tool movements are controlled and monitored during the ILI operation.

In-service pipelines must be adequately cleared and prepared to receive ILI tools. While ILI tool vendors deliver the ILI tool to the pipeline launcher site location, PG&E's GTGC and GPOM teams prepare the launching or receiving pipeline facilities.

New PG&E Pigging Training Facility

During the current ISM reporting period, the ISM observed that PG&E initiated construction of a "training pigging loop" at its Winters Gas Training Facility. The training loop is scheduled to be in-service in March 2024. The training loop, shown in Figure 23 below, will incorporate a new pig launcher barrel and receiver barrel design. PG&E expects the new launcher and receiver design to resolve deficiencies identified with the 2022 pigging operations incident discussed below.

Figure 23: New Construction of the new Training Pigging Loop

Pigging Operation OQ Updates from Calistoga Investigation

In April 2022, two PG&E employees were injured performing an out-of-service (OOS) pipe segment pigging operation - one resulted in a fatality. The serious injury fatality (SIF) incident, referred to as the Calistoga incident, occurred during a pipe dewatering operation using pressurized air and foam pigs to remove residual water following a hydrostatic pressure test. The operation took place on an OOS 6-inch transmission line. After approximately 10 pigging runs, a pig became stuck leading the PG&E team to prepare a reverse pressure air flow operation with a portable compressor. The purpose of the reverse pressure operation was to attempt to free the pig. PG&E's employees sustained injuries when the team attempted to recover the pig from the pig launcher barrel, which was temporarily serving as the pig receiver barrel.

PG&E fully investigated the Calistoga SIF incident and made design changes to pig launching and receiving barrel equipment used on temporary hydrostatic pressure test pipe segments. PG&E also introduced changes to pigging operation personnel assignments, and OQ requirements. PG&E amended the OQ to improve operator safety during pigging operations.

In-service pipeline pigging operations utilize the flow of natural gas or a self-propelled robotic system to move the pig through the pipe segment. Alternatively, out-of-service (OOS) pipelines utilize pressurized air, inert gas, or liquid such as water to propel the pig along the pipe segment.

Methods used to propel pigs in OOS pipe segments introduce stored hazardous energy and line-of-fire risks in the form of pressure differentials that create potential for serious injury if not adequately controlled. To safely perform operations and mitigate these hazards/risks, PG&E's pigging operation and Gas Design Standards (GDS) project indicated that specific OOS pigging procedures must be created; and temporary piping associated with launcher and receiver barrel installations must be adequately designed and supported.

OOS pigging operations include, but are not limited to, the following operations:

- Cleaning and drying pipe with foam pigs after hydrostatic pressure testing;[29]
- Removing and cleaning pipe of residue liquid and contaminants;
- Commissioning or inspecting pipe segments with pig mounted gauge plate, caliper, and inspection tools; and
- Deploying tethered or self-propelled robotic ILI systems.

PG&E relies on third-party OQ contractor teams to prepare and operate OOS pigging operations. PG&E employees perform the construction of temporary pipe and elbow segments required to attach pigging launcher and receiver barrels to support OOS inspection operations.

PG&E indicated to the ISM that PG&E's third-party contractors are required to qualify team members using a 1:1 team member control ratio. This ratio requires that there be at least one OQ team member for each unqualified team member on the pigging job site.

The ISM observed that PG&E is updating employee training, testing, and OQ certification guidelines with an expected implementation planned for Q2 2024. Currently, PG&E employees are qualified based on their specialized job functions (GTGC, TPCO, and GPOM).

Federal regulations, 49 CFR 192 subpart N, require PG&E to publish and follow a written qualifications program. The ISM observed that PG&E has defined approximately 144 OQ tasks

[29] Hydrostatic pressure testing establishes strength of section of pipeline.

including three for pigging in-service pipelines - referenced by PG&E OQ code numbers 1631, 1641, and 5921. These three PG&E OQ requirements are designated as 'Contractors Only' and require contractors to properly train and qualify their pigging operation team members. Contractors must present their OQ credentials to PG&E prior to being assigned to a pigging operation. As noted above, PG&E is currently developing curriculum and requirements for OQ (and related code numbers) specifically for PG&E employees.

PG&E's gas system and temporary pig launcher and receiver barrel designs have been redesigned to incorporate recommendations provided in the Calistoga SIF report and subsequent proposed PHMSA rules. The modifications are intended to improve pressure isolation from the connected pipe segment, provide a mechanical indicator of launcher and receiver barrel pressure, or prevent the launcher or receiver barrel from being opened if the pressure has not been relieved.

PG&E reported that the Winters Gas Training Facility's training pigging loop will be operational at the end of Q1 2024. PG&E indicated that the training will include a variety of procedures for proper recovery of a stuck pig and a written and performance-based test.

LEAK MANAGEMENT

No new material changes were identified during the current ISM reporting period associated with PG&E's leak management operations. Reporting on leak management operations, including leak grading and reporting, leak survey and Advanced Mobile Leak Detection, and other emerging issues regarding leak management will only continue should the ISM observe any material change in status.

TEE CAP REPLACEMENT PROGRAM

On October 8, 2022, there was an explosion at 2793 River Plaza Dr., a residential area in Sacramento, California, with no injuries or fatalities reported. PG&E hired Exponent, an engineering consulting firm, to study the incident. Exponent issued its final report in 2023 that provided findings on the cause of the incident. PG&E used Exponents findings, in part, to perform an internal Root Cause Evaluation (RCE) and develop corrective actions.

As reported in ISM Report 3, the RCE found the direct cause of the incident to be a cracked tee cap[30] that led to a gas leak. The tee cap in question was a specific vintage that was known to be subject to cracking; and therefore, it was part of a PG&E proactive tee cap replacement program established in 2012 by PG&E to address such issues. The RCE determined the root cause to be that the threshold for tee cap replacement in PG&E's tee cap replacement program was not low enough to include the tee cap that failed. The RCE included a contributing cause, which was the loss of coupon in the tee cap increased the amount of gas that could flow through a crack, increasing the severity of the leak once it occurred. The tee cap is designed so that

[30] A tee cap is the portion of a tapping tee that covers the open leg and prevents gas from escaping. A tapping tee is used to connect a service line to a gas distribution line and includes a mechanism to cut into the service line. One leg of the tee is closed and used if the service line requires access, and is capped with a tee cap, including a sealing O-ring to prevent gas from escaping.

when the hole is made in the existing plastic pipe the coupon, or the piece of pipe that was cut out, stays inside the cutting mechanism, which limits the amount of gas that can pass through the cutting mechanism and into the tee cap. The RCE provided corrective actions and PG&E created Corrective Action Plans for each. The corrective actions were as follows:

1. The twenty-four tee caps associated with the original installation were replaced and provided to Exponent for analysis.
2. Evaluate pacing and scope of current tee cap replacement program & determine if changes are required. Make appropriate changes to the DIMP Risk model and tee cap prioritization, if required.
3. Incorporate a factor into the risk model indicating likelihood of a dropped coupon.
4. Review options to increase the likelihood of detecting gas inside residences.

The first corrective action was undertaken and completed immediately after the incident.

PG&E created a Corrective Action Plan to address the second corrective action, in which it evaluated the tee cap replacement program scope, as well as the current DIMP Risk Model methodology around tee caps and their associated risk calculations.

Regarding analysis of the tee cap replacement program, the program is embedded within PG&E's DIMP risk model, in which threats and consequences are evaluated to determine the risk associated with the tee caps and to rank the tee caps in accordance with their risk scores. PG&E's risk ranking of tee caps determines the priority of replacement within the tee cap replacement program. As part of PG&E's DIMP risk model, a mitigation analysis is performed which evaluates the effectiveness of potential mitigation actions on the risk scores generated by the risk model. Historically, the tee cap mitigation analysis included all threats addressed by the risk model. PG&E evaluated whether threats not mitigated by the tee cap replacement program should be included in the mitigation analysis (i.e., landslides, earthquakes, etc.), as these threats are included in the risk calculations, but not necessarily mitigated by the tee cap replacement program. Therefore, PG&E is in the process of implementing changes to the tee cap mitigation analysis in which a portion of the DIMP Risk Model that contains only tee cap specific threats is used. PG&E asserts that this should ensure that the tee cap replacement program is focusing on tee cap specific risk, instead of overall pipe segment risk. PG&E approved this change, and expects to implement the change in the next DIMP Risk Model run. The ISM will continue to follow PG&E's progress in this area.

PG&E performed a review of its DIMP Model related to tee caps, including the calculations for RoF, which is the product of LoF and CoF. During PG&E's review, PG&E identified inconsistent severity factors related to tee caps. PG&E noted that the field personnel who entered the data would characterize a tee cap failure as a Material Failure in some cases, and as an Incorrect Operations Failure in others. Each of these failures would be treated with different severity in the model. PG&E reviewed data on PG&E incident rates observed on tee caps, as well as PHMSA (industry) data to determine which failure method was more appropriate. PG&E's review determined that material failure was the appropriate failure method, which corresponds to the lower severity factor. PG&E considers this action closed as the change was implemented in the latest DIMP Risk Model.

Dropped coupons,[31] were discussed extensively in ISM Report 3. As reported in ISM Report 3, PG&E set a due date of December 15, 2023 to incorporate the likelihood of a dropped coupon into its DIMP Risk model. During the current ISM reporting period, PG&E began collecting data for tee cap failures where there was a dropped coupon. Typically dropped coupons are a result of installation practices; therefore, where a dropped coupon is identified, there is a higher likelihood that other dropped coupons exist within the same installation. PG&E leadership indicated to the ISM, that despite not completing the corrective action by the deadline, PG&E still plans to incorporate the likelihood of a dropped coupon into its DIMP risk model. The incorporation of a "wall to wall pavement" risk factor into the DIMP risk model, as discussed in ISM Report 3, is still being evaluated by PG&E.

The final corrective action proposed by the RCE involved a review to increase the likelihood of detecting gas inside residences. During the current ISM reporting period, PG&E indicated that this is still being evaluated, and that in a separate effort, PG&E has piloted the use of in-home methane detectors on inside meter sets.

The ISM will continue to monitor PG&E's progress under these Corrective Action Plans.

BTEX MEASUREMENT & MONITORING

As reported in ISM Report 3, in early 2023, the CPUC's Safety and Enforcement (SED), Gas Safety and Reliability Branch (GSRB) issued a Directive requiring PG&E to provide a plan to develop and implement a procedure to measure and monitor Benzene, Toluene, Ethylbenzene, and Xylene (BTEX) in its natural gas pipeline system. PG&E responded to the Directive with its plan to implement measuring and monitoring procedures for BTEX (BTEX Plan). PG&E's BTEX Plan included a timeline outlining the timing of critical tasks in developing and implementing its procedure to measure and monitor BTEX. These tasks included determining sampling locations and frequency, evaluating sampling methods and identifying appropriate labs to perform testing, developing a database to retain sampling data, and to develop appropriate recordkeeping processes and practices.

During the current ISM reporting period, the ISM interviewed PG&E leadership and discussed PG&E's progress on the BTEX plan. PG&E indicated that it selected sampling locations where gas enters the pipeline system, which includes border receipts, storage facilities, local producers, and transmission pipeline interconnections, in accordance with SED guidance. PG&E aimed to collect samples twice per year, during high flow conditions (winter) and low flow conditions (summer) on the system, with two test bottles being taken for analysis at each sampling point. PG&E identified approximately 63 sample locations on their system and began sampling, with fifty-eight sample locations (114 total test bottles) taken in 2023, and 7 sample locations (12 test bottles) taken in 2024. Two sample locations only collected 1 sample bottle at each location in 2024; hence the 12 versus 14 bottles. PG&E reported that this will be remedied before the next round of samples.

[31] A Coupon is the piece of pipe that is cut out when it's tapped. The coupon stays in the cutter and limits the amount of gas that can flow through the tee. A dropped coupon is when that piece (the coupon) is dislodged or falls out of the cutter.

In accordance with the BTEX Plan, PG&E developed processes for the collection, transportation, and testing of samples. PG&E indicated that there is a 3-to-4-week lag time in receiving results from the laboratories from when samples are delivered. The laboratories supply sample bottles filled with an inert gas, and there are a limited number of bottles that can be supplied. This supply constraint potentially limits the number of samples PG&E can collect each sample period. Samples are collected by existing PG&E operations and maintenance crews, who receive sample collection related training. Due to the volume and pressure of the samples of natural gas, PG&E considers the samples to fall under the Materials of Trade clause; the handling and transportation of which are regulated by PHMSA. PG&E indicated that it utilizes qualified contractors to transport the samples from PG&E to the laboratories for testing. With the initial sampling locations and a two times per year sampling frequency, PG&E has indicated that while there are challenges with scheduling and notifications, it appears manageable to perform this sampling with existing crews, and the laboratories identified.

PG&E developed a database to collect and retain sampling records, and established recordkeeping process and practices to ensure these records are retained appropriately. PG&E's database assembles sample information, including sampling date, location and laboratory results and produces graphical outputs tied to GIS that PG&E can ultimately use to analyze data trends or anomalies. The database is considered the record retention location, with laboratory results and chain of custody forms being kept on PG&E's share drive.

As this program is in its infancy, PG&E has been meeting with SED each quarter to discuss the plan and progress made. PG&E notes that it is still awaiting guidance from the California Office of Environmental Health Hazard Assessment (OEHHA) and California Air Resources Board (CARB) as to the allowable threshold levels for BTEX in natural gas pipelines.

The ISM intends to continue monitoring both the development and implementation of PG&E's BTEX measurement and monitoring plan. Reporting of activities will only continue should the ISM observe any material changes in status.