PG&E
INDEPENDENT SAFETY MONITOR STATUS UPDATE REPORT

October 4, 2022

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BACKGROUND

In conjunction with Decision 20-05-053, the Bankruptcy Plan of Reorganization for Pacific Gas and Electric Company (PG&E)[1] and the findings included in the Kirkland & Ellis LLP Federal Monitorship Final Report dated November 19, 2021 (Federal Monitorship Report)[2], through Resolution M-4855[3] the California Public Utilities Commission (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 initial areas of focus were designed to take into consideration the findings from the Federal Monitorship Report and provide complementary oversight and monitoring activities that are not unnecessarily duplicative, consistent with CPUC Resolution M-4855. The activities being performed by the ISM are consistent with the current draft of the Project Plan (dated August 3, 2022) and assumes the current draft of the Project Plan will be finalized without significant changes.

The six initial focus areas for PG&E's electric operations and infrastructure include aspects of 1) System Inspections and Repair; 2) Vegetation Management (VM); 3) System Hardening; 4) Situational Awareness; 5) Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS); and 6) Implementation of Corrective Action Plans initiated as a result of the Enhanced Oversight and Enforcement Process (EOEP). For PG&E's gas operations and infrastructure, the six initial focus areas include aspects of 1) Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP); 2) Leak Survey Program; 3) Pipeline Replacement Program; 4) Locate and Mark Program; 5) Pipeline Patrols; and 6) In-line Inspection (ILI) program.

The PG&E Independent Safety Monitor Status Update Report (ISM Report) outlined herein was developed based on the stipulations of the ISM Contract and the reporting directive included within CPUC Resolution M-4855. The ISM Report is designed to summarize the oversight activities performed by the ISM during the period described below and the related observations.

The ISM Report also includes a summary of potential emerging risks identified during the oversight activities performed during this 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 observation, in consultation with the CPUC, it may be determined to perform additional monitoring activities.

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[1] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M338/K816/338816365.PDF
[2] https://s1.q4cdn.com/880135780/files/doc_downloads/wildfire_updates/2021/11/1524-1.Exhibit-Monitor-Report.pdf
[3] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M397/K322/397322603.PDF

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 only monitored to the extent agreed upon within the confines of the ISM Contract.

As it is early in the monitoring process, the information included in this initial report should be considered a "snapshot" of observations to date. Although an effective start to the monitorship has been realized (including data collection, review, and analysis; observations; and interviews), the ISM reports are a condensed summary of the totality of work performed to date. Furthermore, the ISM will continue to perform monitoring activities related to the observations noted herein. 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 come from both internal PG&E meetings, presentations, and data requests, as well as external reports and may not always be footnoted.

The ISM has conducted in-field reviews of PG&E's Vegetation Management (VM) and Enhanced Vegetation Management (EVM) inspections. Initial observations from the in-field reviews are included in the "Field Review of Inspections" section of this report. Due to the timing of this report, the ISM has not yet completed its analysis of the initial observations. This will be an area of elaboration in future reports, including thorough analysis of the data, observations, and monitoring of related trends.

ISM REPORT STRUCTURE

As this is the ISM's first update report, the period encompasses January 27, 2022, through September 30, 2022. Going forward, the ISM anticipates submitting reports at the end of calendar quarters one and three, with each report covering activities in the previous six months.

The ISM Report is structured as follows:

- General Observations – ISM observations that may have been identified during an analysis or review of information associated with a specific division or function of PG&E (e.g., Electric, Gas, etc.) but may potentially have broader impacts (e.g., corporate wide).

- Electric Operations Observations – ISM observations that stem from specific activities performed by the ISM in specific areas within Electric Operations and which primarily impact Electric Operations.

- Gas Operations Observations – ISM observations that stem from specific activities performed by the ISM in specific areas within Gas Operations and which primarily impact Gas Operations.

- Emerging Observations – ISM observations that are being monitored but are not covered in this report.

GENERAL OBSERVATIONS

SUPPLY CHAIN

Critical Spares and Inventories

In March 2020, the World Health Organization declared the Novel Coraonavirus-2019 (COVID-19) viral outbreak a global pandemic.[4] The impacts of the global pandemic have been far reaching, including affecting the global supply chain of goods and services across numerous industries. Some of the effects of the global supply chain on the U.S. electric and gas utility sectors include lengthened lead-times associated with ordering and receiving various goods, limited availability for unscheduled manufacturing production, and limited quantity of goods available for purchase, which in turn has had an effect on inventory levels of goods on hand. For example, due to the effects of global supply chain issues, lead times for certain transformers have increased from 38 weeks to approximately 38 months.[5]

During the period, several observations related to supply chain were identified by the ISM following participation in meetings, document reviews, and follow-up interviews. These observations included: 1) an inability to source quantities of certain supplies that, according to PG&E, "could create risks for [their] Wildfire Mitigation Plan (WMP) commitments[6]; 2) a shortfall of critical spares within certain electric departments; 3) a lack of equipment required to perform select monitoring activities; and 4) a general lengthening of time required to source supplies.

In response to the ISM's data requests regarding supply chain concerns, PG&E provided documentation on nine types of equipment where long lead times could put certain electric distribution and transmission WMP commitment target delivery dates at risk. Information was also provided to the ISM which indicated that critical spare shortages and a lack of certain emergency supplies existed in the areas of underground electric transmission and electric substations.

In a May 2022 report to an internal PG&E committee[7], various shortages associated with electric operations were also identified. As noted in the "Asset Age and Useful Life" section of this report, not having critical spares on hand may result in inefficient restoration and potentially prolonged customer outages during an equipment failure situation.

PG&E has shared its plans to replenish the identified shortages of certain equipment over the next three-year period. Further, PG&E has indicated that the transmission engineering and asset management groups have been working together to develop a hazards and threats matrix which supports prioritization of purchases being made in the early years based on the interim risk rankings of the related assets.

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[4] https://pubmed.ncbi.nlm.nih.gov/32191675
[5] Jeff Postelwait. Transformative Times: Update on the U.S. Transformer Supply Chain, July 12, 2022, T&D World
[6] Data request response received from PG&E
[7] Internal PG&E Report

Additionally, shortages of replacement equipment were identified in several areas within the electric substation group. It was noted that certain spare components are not tested and may not be operational.

Relatedly, the ISM interviewed several members of PG&E's supply chain and procurement departments. These groups informed the ISM that: 1) the underground transmission and the substation groups operate independently of PG&E's supply chain department and are responsible for the management of their own inventory levels; 2) inventory from these two departments are not managed within the core SAP inventory management systems; and 3) inventory shortfalls are not reported or flagged in the Emergency and Critical Spares Inventory Readiness Report that is circulated among senior management each week.

The ISM received and reviewed PG&E's procedure regarding materials planning for emergency preparedness and response[8] (which applies to all aspects of emergency materials planning, including emergency stock analysis, critical spares strategy and emergency readiness reporting). The ISM also received and reviewed PG&E's procedure associated with critical electric distribution operating equipment[9] (intended to ensure system-wide consistency in use with SAP to create, track and manage distribution critical operating equipment). It was noted in a December 2019 report regarding emergency and critical spares inventory readiness[10] that "Critical spares for electric transmission line or substation equipment inventory management is not in scope for Supply Chain."

The ISM has begun to receive copies of a report regarding the emergency and critical spares inventory readiness and will monitor going forward. This report, which lists over 3,000 inventory items contains: 1) information on the Minimum Safety Supply (MSS) quantity/level for each item (as determined in accordance with the procedure associated with materials planning for emergency preparedness and response noted previously); 2) the existing inventory levels; and 3) the current projected delivery times for each replacement item.

PG&E calculates a readiness percentage that takes into account the current usage rates and inventory levels, and the ability to replace these materials in a timely manner as used, in order to maintain the MSS levels. A score less than 100% may indicate the current inventory levels for actively used inventory items below the MSS level, or that long lead times could result in inventory levels dropping below the MSS. The average calculated readiness percentage for all inventory items included in the report as of August 2022, was 95.75% (with approximately 5% of the inventory items having a score less than 100%). PG&E Supply Chain has indicated that, historically, the average readiness percentages have tended to be higher (in the 97-98% range), and that with supply chain delays, this measure has slowly started to decrease over time.

[8] Internal PG&E Procedure
[9] Ibid.
[10] Internal PG&E Report

The ISM has also started to receive copies of a weekly dashboard report associated with material availability[11] which is distributed to leadership in the electric and gas departments. This report notes that, "Supply challenges are widespread and unprecedented in scale and duration, driven by disruption in all areas of supply chain (materials and labor). Demand increases driven by a bullwhip response from all utilities have exacerbated the situation leading to further lead-time extensions. Additionally, a rapid increase in demand at PG&E for certain materials is outpacing sourced capacity leading to extended lead time."

In this report, PG&E indicates that mitigation strategies are being deployed across all impacted areas as needed to drive recovery. Its mitigation plans include:

- partnering with line of business to determine highest priority work and allocating available supply accordingly;
- referring jobs to available substitute materials where possible to consume surplus inventory and reduce backlog on short materials;
- requesting additional capacity allocation and prioritization of PG&E orders with suppliers;
- enhanced communications with suppliers, greater visibility with senior leadership for performance slips;
- placing advanced orders ahead of standard lead time to lock in production capacity and expediting critical materials to minimize transit time; and
- partnering with engineering to prioritize and expedite the qualification/onboarding of new sources of materials where PG&E is currently at or exceeding sourced capacity.

This weekly dashboard also provides a summary of "Current Work Impacts/Delays and Sourced Capacity vs. 2022 Demand" for items flagged in both the electric and gas divisions. Work delays of up to six weeks have been identified for certain categories of constrained supplies on the electric side, and up to 10 weeks for specific categories of constrained supplies on the gas side. For these supply constraint categories, PG&E is projecting estimated recovery dates from Q3 2022 to Q1 2023. The ISM will continue to monitor this evolving supply chain situation and PG&E's mitigations, with a focus on tracking critical inventory levels that may have safety or customer impact implications.

ASSET AGE AND USEFUL LIFE

Asset age commonly refers to how long an asset/piece equipment remains in operational service, while useful life commonly refers to the estimated length of time equipment can be expected to effectively contribute to operations. Asset age is often one of many factors considered when determining when an asset is targeted for replacement. Other factors may

[11] Ibid.

include utilization (e.g., number of times equipment operates), performance (e.g., no, or minimal degradation in operating as expected), asset wear (e.g., amount of corrosion), etc.

During the period, the ISM reviewed data provided by PG&E and performed analyses associated with the age of equipment in service and the estimated length of time equipment can be expected to contribute to operations.

In the Federal Monitorship Report, PG&E's Conditions of Probation, Condition 9, lists "Asset Age Condition" for "certain critical transmission tower components in High Fire Threat Districts" as a condition for which PG&E needed to provide a reasonable record of age and installation data for those components. The ISM received an update on the asset age and useful life, specifically in regard to this condition from the "Asset Information Collection" (AIC) Program. The AIC Program showed completion for all commitments targeted for Q1 2022. The Federal Monitorship Report indicates that "PG&E plans to complete its work for all 550 High Fire Threat District (HFTD) transmission circuits by the end of 2022" and a risk model was scheduled to be developed by March 2022. According to the AIC Program, the "Useful Life Model v1.0" was completed in Q1 2022 with a "Useful Life Model v1.5" release on track for completion by Q1 2023. The AIC Program notified the ISM that completion of all HFTD circuits by the end of 2022 is off track but is believed to be recoverable through increased resources and a one-month cushion which had been included in the plan.

Across the divisions (e.g., Transmission, Distribution, Gas, etc.), the ISM has observed numerous PG&E asset ages that are significantly older than the related industry average useful life and the related PG&E average age of asset failure. The ISM has questioned PG&E and performed various activities to understand the volume of PG&E assets beyond these averages and PG&E's ability to mitigate/remediate these volumes and the resulting potential operational and safety concerns.

The ISM noted some departments have identified the number of necessary units of equipment and the related financial resources required to mitigate/remediate the identified gaps; however, in some areas the current allocation of resources does not support PG&E's identified required resources. The emerging risk relates to the volume of assets that have the potential to fail within close time proximity to one another.

Substation Asset Age

During the period, the ISM reviewed data provided by PG&E regarding the average age of certain PG&E substation assets. For example, PG&E reported having certain equipment with an average age of 60 years and an average industry service life of 40 years (i.e., 20 years older than the industry average). Further, PG&E reported an average age of failure for this equipment as 70 years with 47% of this equipment exceeding this average age of failure.[12]

Similar observations were identified with respect to two other types of equipment. For one type, PG&E reported having certain equipment with an average age of 48 years, compared to

[12] Internal PG&E Report

an average industry service life of 40 years (i.e., eight years older than the industry average). For this equipment type, PG&E reported an average age of failure of 57 years with 56% of this equipment type exceeding this average age of failure. [13]

For the other type of equipment, PG&E reported an average age of 53 years and an average industry service life of 35 years (i.e., 18 years older than the industry average). In this case, PG&E reported an average age of failure of 55 years with 52% of this equipment type exceeding the average age of failure.[14]

In summary, if only utilizing asset age to determine an asset's useful life, PG&E would have to purchase and install over 2,000 components of the aforementioned equipment in order to bring the asset age of the equipment in these three categories down to the PG&E average age of failure for each equipment type. A significantly higher investment would be required to get each asset category reduced to the industry average. As noted in the Supply Chain section above, the current global supply chain issues may extend the availability and receipt lead times.

Per discussions with PG&E's Asset Strategy team, in addition to asset age, there are several other factors taken into consideration when determining the useful life of an asset. Depending on the asset, these factors may include: 1) performing insulating oil testing; 2) monitoring operational counts; 3) analyzing Accumulative Critical Current; 4) performing operation testing to determine if clearing times are per design; 5) performing physical condition assessment through inspections (rust, oil leaks, etc.); and 6) monitoring asset maintenance history, etc.

To actively manage assets and mitigate concerns associated with asset age, depending on the asset, PG&E may opt to: 1) increase testing and trend testing results; 2) add power factor testing to catch additional modes of failure; 3) perform additional routine inspections (e.g., monthly/bi-monthly); 4) perform supplemental inspections associated with preventive and corrective maintenance; 5) enhance equipment monitoring to drive "just-in-time" replacement to prevent in-service failures; 6) ensure adequate emergency material (mobile and Capital Emergency Material (CEM) inventory); and/or 7) apply life extension program activities.

Figure 1 (below) serves as an example of how performing Dissolved Gas Analysis (DGA) testing on electric transformers may guide PG&E to leave certain older transformers in service rather than removing the asset purely based on age.

In this analysis, PG&E grouped the in-service assets by age from A (0-4 years old) to V (105-109 years old), then mapped the DGA test results with Code 1 (i.e., the best condition) through Code 4 (i.e., the worst results). Code 3 identifies when the asset's condition has reached a point where action beyond normal maintenance is required. PG&E's DGA test results indicate that despite the transformer's age, the oldest transformers (i.e., S-V (90-109 years old)) are amongst the Code 1 test results. One of PG&E's key take-aways from the analysis is that, from

[14] Ibid.

an insulating oil perspective, there are a "high percentage of asset population Code 1 and 2 (good condition)"[15] transformers. Additionally, PG&E indicated that as degradation in performance is identified through the various tests performed, the frequency of testing, monitoring, and/or analysis is increased to prevent in-service failures.

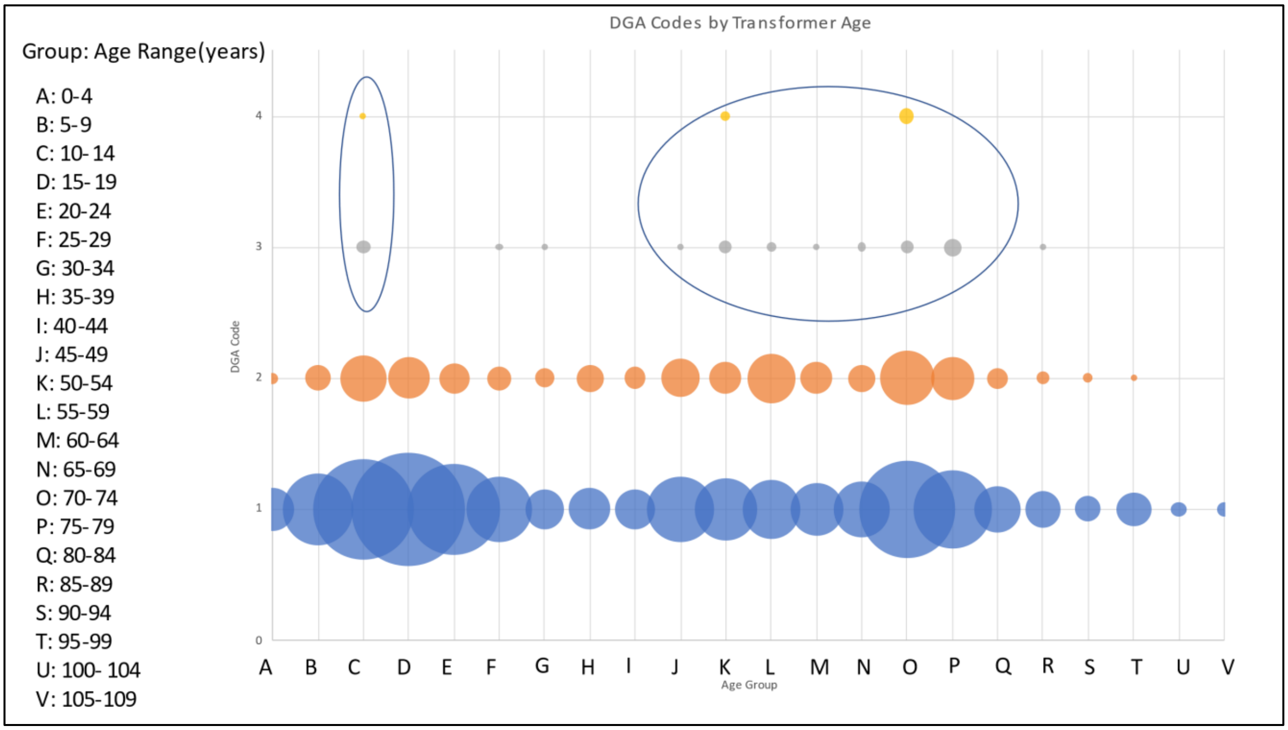

Figure 1. DGA Codes by Transformer Age[16]

Further, per discussions with PG&E leadership, PG&E is working on an Integrated Grid Plan that will take numerous factors (e.g., Capacity, Asset Health, Wildfire Risk and Reliability) into account to strategically identify and prioritize asset replacements and reduce a "run to failure" replacement approach. The Integrated Grid Plan (IGP) is expected to have a 10-year horizon. Consistent with the observations regarding asset age and useful life, the IGP identified that approximately 60% of substations are forecast to have overloaded assets[17] by 2032. The ISM will continue to monitor and analyze PG&E's progress toward the prioritization of asset replacements; the development, implementation and reduction of substation asset ages and useful lives; and the trends utilized by PG&E to support longer in-service dates for older assets.

Underground Transmission Asset Age

Throughout the Western United States, utilities have instituted various systems aimed at reducing the number and size of wildfires. In addition to measures such as EPSS and PSPS, in July 2021, PG&E announced a multi-year infrastructure safety initiative to place underground

[15] Internal PG&E Presentation
[16] Ibid.
[17] Defined by PG&E as "substations with banks or feeders expected to be at >90% of capacity by 2031"; Internal PG&E Presentation

approximately 10,000 miles of power lines in and near high fire-threat areas. PG&E is also assessing its existing underground transmission assets.

During the period, the ISM reviewed data provided by PG&E related to PG&E's Underground Transmission asset ages and the average age of certain PG&E Underground Transmission assets. For example, 60% of one type of underground transmission cable is beyond its useful life.[18]

PG&E's underground transmission system operates at 60, 70, 115, and 230kV utilizing various cable types such as High Pressure Fluid Filled (HPFF), High Pressure Gas Filled (HPGF), and Cross Linked Polyethylene (XLPE). The high-pressure systems require welded steel pipes between vaults that are vacuum tested during installation and must withstand 200 psi (pounds per square inch) pressure during normal operations. These pipes also require special coatings to overcome long term corrosion. Three high voltage cables can be installed in one fluid or gas filled pipe. The current industry standard underground cable type, XLPE, requires one cable per conduit. Underground cable failures can result in long duration outages, especially if pipes are damaged.

Since 1989[19], PG&E has reported several underground transmission outages from 50 minutes to seven weeks in duration. The report states that certain assets do not have enough spares to make necessary repairs, if needed. PG&E intends to purchase certain quantities of assets to serve as spares. The ISM will continue to monitor PG&E's efforts to increase like-kind inventories as well as determine PG&E's efforts directed towards modernizing their underground transmission cable system.

PG&E also states in an internal report published in May 2022 that underground transmission provides a low-risk score. PG&E, however, currently operates with 60% of certain underground transmission assets exceeding their useful life, thus highlighting the importance of routine monitoring as well as underground system upgrades during planned outages. With certain assets exceeding their useful life coupled with required integrity of certain underground assets, PG&E lists increased cost, unexpected and prolonged outages as potential consequences of failure.

The ISM will continue to monitor and analyze the effects that asset age and useful life, coupled with longer lead times and reduced availability of certain equipment due to the global supply chain issues, have on outages and the related safety concerns.

CONTRACTOR MANAGEMENT

The Federal Monitorship Report identified "continuing to improve contractor management" as one of the "most salient challenges PG&E faces going forward" and noted that "consistent with industry practice, [PG&E] substantially relies on its contract workforce to perform wildfire mitigation efforts." Case in point, approximately two thirds of PG&E distribution

[18] Internal PG&E Report
[19] Ibid.

inspectors were contractors in the 2022 reporting period-to-date. Because of this heavy reliance on a contractor workforce, contractor management is critical to PG&E's ability to execute operational functions safely.

Training

From observations made in the Federal Monitorship Report to the current time period, PG&E modified its distribution inspector training and related training requirements and established new testing processes. The same distribution inspector training is completed by PG&E employee inspectors and contractor inspectors; however, due to bargaining unit contracts, employee inspectors do not take the skills assessment test at the end of the training. The ISM will continue to monitor these training initiatives and the related results.

The ISM has toured the training facility (Livermore), conducted interviews with training personnel, and attended certain inspector training sessions. The training facility uses both classroom and actual infrastructure with real issue scenarios for hands-on training and ensures that all training takes place in the same location. As the training program is less than a year old, updates/adjustments are in process. As the ISM completes its contractor management activities (i.e., reviewing field inspections, shadowing contractor inspectors, analyzing errors/corrections, monitoring enhancements, commitments, conducting interviews, etc.), the ISM will be better able to determine whether inspector training has improved consistency, thoroughness, efficiency and/or demonstration of skills assessment.

The skills assessment is the final test required for contractors before being allowed to perform system inspections in the field. Based on data provided by PG&E, approximately 50% of contractors pass the skills assessment test the first time. Those that do not pass initially have two additional opportunities to retake and pass the skills assessment. Review of related data indicates the overall skills assessment pass rate increases to approximately 95% during the subsequent test retakes. If the contractor fails all three times, a contractor training refresher course is provided that reviews material prior to contractors retaking the exam. If the contractor does not pass this final skills assessment, they are dismissed.

Improvement in contractor inspector training was observed when comparing Livermore training (2022) to that witnessed by the Federal Monitor in 2021. During the Federal Monitorship, the observed field training was provided at various locations across PG&E's territory. The Livermore Electric Training Center provides a centralized location where all inspectors are trained and, in the case of contractors, tested, on issues that could be found in the field.

While improvement was recognized in contractor inspector training year-over-year, interviews with successful and in-field working contract inspectors unanimously revealed a need for future improvements in the training program, including a need for improved hands-on training using the proprietary iPads, software, and decision-making guidance. Those interviewed expressed their knowledge of the equipment as being a result of their powerline infrastructure experience as journeymen linemen; however, they expressed a lack of proper knowledge using PG&E's proprietary inspection technology.

With respect to Gas Operations, the ISM toured the training facility (Winters), conducted interviews with training personnel, and observed certain training sessions. The Winters training facility also uses both classroom and actual infrastructure with real issue scenarios for hands-on training and ensures that all training takes place in the same location. The facility provides employees with simulators for certain types of large machinery (e.g., backhoes, dozers, cranes, etc.) that support teaching both the ability to utilize the equipment while increasing the efficiency and effectiveness prior to training on the live equipment. All activities that are completed in the field are trained at the facility (e.g., commercial driving, leak surveying and testing, installation and removal of equipment, appliance relight processes, welding, etc.). Every gas employee performing work in the field has a training profile that identifies what training is required to maintain certifications and by when. Additionally, training lead time reminders (e.g., 90-, 60-, 30-day reminders) are sent to employees and supervisors to support timely completion of training. The facility also includes a "studio" where training and safety awareness videos and/or virtual training and safety awareness workshops can be recorded/presented.

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 PG&E's "most salient challenges PG&E faces going forward." Accordingly, the ISM has monitored PG&E's core leadership changes.

During the period, the ISM was notified of certain senior leadership changes. The SVP of Electric Operations moved to a different company, resulting in the following shifts in leadership:

- The SVP of Gas Engineering moved to become the SVP of Electric Operations;
- The VP of Electric Engineering, Asset and Regulatory moved to become the SVP of Gas Engineering; and
- The Senior Director, Electric & Gas Acquisition moved to become the VP of Electric Engineering, Asset and Regulatory.

The ISM interviewed each of these leaders regarding their respective new roles as well as the roles they recently vacated. Based on the interviews of these leaders, they indicated that they do not intend to significantly change the overall priorities established by the previous leadership for the respective areas. In several cases, the new leadership participated in the previous leadership's processes that identified and established the current priorities. As such, the "whiplash" effect of new leadership (i.e., new leadership entering and identifying/implementing new priorities and/or processes significantly different from previous leadership) is not expected. However, each new leader has identified certain areas of focus or approaches to be implemented to achieve the overall strategic plans and goals. As these leaders were only in their new roles for approximately one month at the time of their interview, the ISM will continue to monitor the leadership changes and related potential impacts.

During the reporting period, PG&E initiated a Voluntary Separation Program (VSP). In May 2022, invitations were sent to employees in identified job classifications, departments, or job levels who were offered the opportunity to volunteer for the VSP. The process identified August 15, 2022, as the last day a "Separation Agreement" could be signed and returned, followed by a seven-day revocation period (i.e., seven days to revoke the signed Separation Agreement if an employee changes their mind). The ISM will continue to monitor the related potential impacts to core leadership and/or safety resulting from the VSP process.

ELECTRIC OPERATIONS OBSERVATIONS

EPSS CRITERIA CHANGE

EPSS is a program that increases the fault detection sensitivity on enabled powerline circuits such that when a change in current on the EPSS enabled powerline is identified, the EPSS equipment will quickly deenergize the powerline. Following the implementation of a pilot EPSS program in 2021, PG&E in 2022 made the decision to expand its EPSS program to encompass all HFTD and High Fire Risk Area (HFRA) distribution circuits in its service territory. EPSS enablement is designed to reduce the risk of wildfires (which PG&E has indicated is one of its highest priorities). From the implementation of EPSS in late July 2021 through October 2021, PG&E reports a 40% reduction in ignitions as compared to the past three-year average; and an 80% reduction in the CPUC-reportable ignitions as compared to the past three-year average for the same period.[20] Implementing an EPSS program in order to de-energize distribution circuits by providing sensitive fault detection settings increases the number of outages and the number of customers affected as some outages might not have occurred had normal settings remained in place.

EPSS also includes the disabling of automatic reclosing of circuit breakers. The amount of time required to patrol EPSS enabled circuits potentially increases due to the larger area affected by the outage. In essence, activating EPSS on circuits reduces fire risk at the cost of increasing the number of outages and affected customers.

PSPS is a planned de-energization of circuits within a geographic area that is based on forecasted meteorological conditions and thresholds as set forth in PG&E's PSPS protocols. PSPS is another wildfire mitigation tool utilized by PG&E; however, PSPS and EPSS are unrelated operationally in how they are executed.[21] Although both PSPS and EPSS are complementary wildfire mitigation programs, combining EPSS with PSPS exposes customers to the possibility of experiencing additional and/or longer duration power outages. Fire risk is reduced at the cost of other reliability related impacts. The ISM notes that as part of its May 26, 2022 "Issuance of Revision Notice for Pacific Gas and Electric Company's 2022 Wildfire Mitigation Plan Update", Energy Safety requested several report revisions, including RN-PG&E

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[20] PG&E Wildfire Mitigation Plan Update – Revised, 7/26/22. Three-year average is for the years 2018-2020.
[21] Ibid.

22-12, which stated that "PG&E has failed to provide sufficient evidence to support its extensive use of Enhanced Powerline Safety Settings and instead relies on the findings of a time-limited pilot deployed in 2021." To address this concern, Energy Safety requested that PG&E take the following actions: 1) explain how it will analyze EPSS deployment and modify settings; 2) reassess customer impacts associated with more widespread use of EPSS; 3) explain its EPSS customer impact mitigation plan; 4) detail its customer outreach plan; 5) present an EPSS staffing and resourcing plan; 6) detail an EPSS benchmarking plan; and 7) submit monthly EPSS data reports through the end of 2022.

The ISM is monitoring the evolution of the program and restoration times and will report on any substantive implementation changes or investigate any performance or impact trends.

While evaluating historical fires, PG&E determined that had it been using its original enablement criteria, and had EPSS been in effect at that time, the circuits would have been enabled at times when certain fires occurred. Examining historical acres burned, PG&E also noted that its original enablement criteria would have resulted in EPSS not being active during times when 5% of acres burned (from any cause), and 74% of historical PG&E ignitions occurred. As a result, PG&E determined that it should amend the enablement criteria to try to capture the conditions which existed during these other historical ignition and wildfire events.

In June 2022, PG&E made the decision to modify the conditions under which EPSS circuits are enabled. The new EPSS enablement criteria contained two modifications. The first modification is that all EPSS circuits will be enabled unless the FPI is ranked R1 (low) and conditions are damp or calm (wind speed < 19 mph, relative humidity >75%, or dead fuel moisture >9%)[22]. The second modification is that instead of using a single model run as the day-of-forecast, PG&E will use multiple forecasts to determine if a circuit would be enabled for a given date. Accordingly, if any of the forecasts that occur over the multiple-forecast period predict conditions for EPSS enablement on a particular circuit, then EPSS will be enabled on that circuit on that day.

PG&E has projected that the net impact to customers from shifting the model selection process is an expected 42% increase in HFTD customer minutes interrupted. PG&E has also projected that when adding the change of enablement criteria (i.e., shifting from the pre-June 2022, enablement criteria to the new, "always on unless disabled" criteria) to the model selection change, the net impact is expected to result in a 98% increase in HFTD customer minutes interrupted. Since the criteria change, the actual increase in customer minutes through August 2022 has been approximately 50%. The ISM notes that for the three-week period prior to the EPSS enablement criteria change, roughly 17,000 miles of EPSS circuits were enabled, with an average of 53 weekly outages on EPSS-enabled zones. For the eleven weeks following the EPSS criteria change, the number of EPSS-enabled miles increased to approximately 34,000, with weekly outages on EPSS-enabled zones increasing to an average of 100.

Given the increase in EPSS-enabled miles and the projected increase in customer impact as a result of this criteria change, the ISM requested information on the cost/benefit analysis

[22] Revised 2022 WMP in Figure RN-PG&E-22-12-01

behind the decision-making process. In response, PG&E indicated that while it had calculated potential increase in customer minutes interrupted, a detailed Risk Spend Efficiency (RSE) type analysis had not been conducted. PG&E noted that while it had originally calculated an RSE for EPSS settings of approximately 103-105 (based on the 2021 EPSS pilot data of ignition reduction), it did not recalculate the RSE value based on the June 6 change in EPSS criteria for 2022, citing that it was still refining and adjusting the criteria based on lessons learned from fires across California and the Western United States. PG&E has indicated that a new RSE will be calculated at the end of the 2022 fire season. The ISM will review the new RSE when it is available.

Given that such a large projected increase in EPSS outage minutes would require additional resources to patrol larger numbers of tripped circuits, and could put pressure on restoration times, the ISM followed up with questions on PG&E's resourcing plan for this projected increase in EPSS interruptions. The plan that was described to the ISM is similar to the restoration response and resource staffing plan presented in PG&E's revised WMP (Response to Critical Issue RN-PG&E-22-12 Remedy #5). This plan includes an update to its Storm Outage Prediction Project (SOPP) model, staging of helicopter assets throughout its service territory, a plan to surge when necessary, using inspection personnel (both internal and contractors), and shifting of local teams from planned work to outage response when high volumes of customers are out for extended duration.

The ISM has been tracking EPSS performance and PG&E response times. PG&E has revised its response time standard to respond to outages in HFTD areas, where they can safely do so, within 60 minutes as compared to the prior standard which required a response to a low-level outage within 24 hours. For the EPSS program, PG&E has set a target of 80% of responses within 60 minutes. As of August 23, 2022, 86% of the year-to-date responses have been within 60 minutes, with an average response time of 45 minutes. Five divisions have been experiencing lower than target levels, with the reasons given for their below target times as "resource constraints and extended drive time contributing to extended response times". The slower-than-target response time is also leading to several of these divisions reporting higher than targeted Customer Average Interruption Duration Index (CAIDI) figures. The ISM will continue to monitor response/restoration times and resource allocations, as well as their combined impacts on customer outage durations as the EPSS program continues.

INFRASTRUCTURE OBSERVATIONS

Distribution Inspections

For the past three years, as part of its annual WMP commitments, PG&E has been inspecting 100% of all Tier 3 distribution structures annually, and one-third of its Tier 2 structures, as part of a three-year inspection cycle that began in 2020. For each of the past three years, PG&E's WMP commitment was to complete its HFTD inspections by July 31. As seen in Figure 2 (below), PG&E missed this target in 2020 (primarily due to the impacts of the COVID-19 pandemic). Although the majority of the committed inspections were completed by the target date in 2021, the company identified, during its record validation, that additional poles after the target date should have been inspected. These supplemental inspections were completed as of December 31, 2021. For 2022, PG&E was able to complete its 2022 WMP commitment of 396,000 HFTD structure inspections by July 31.

The ISM interviewed management of the distribution inspection group in order to better understand the reasons for the delayed start to inspections in each of the past three years, as well as the large increase in field inspectors in June and July 2022. As part of its independent verification process, the ISM was also provided direct access to various inspection records, with observations noted below.

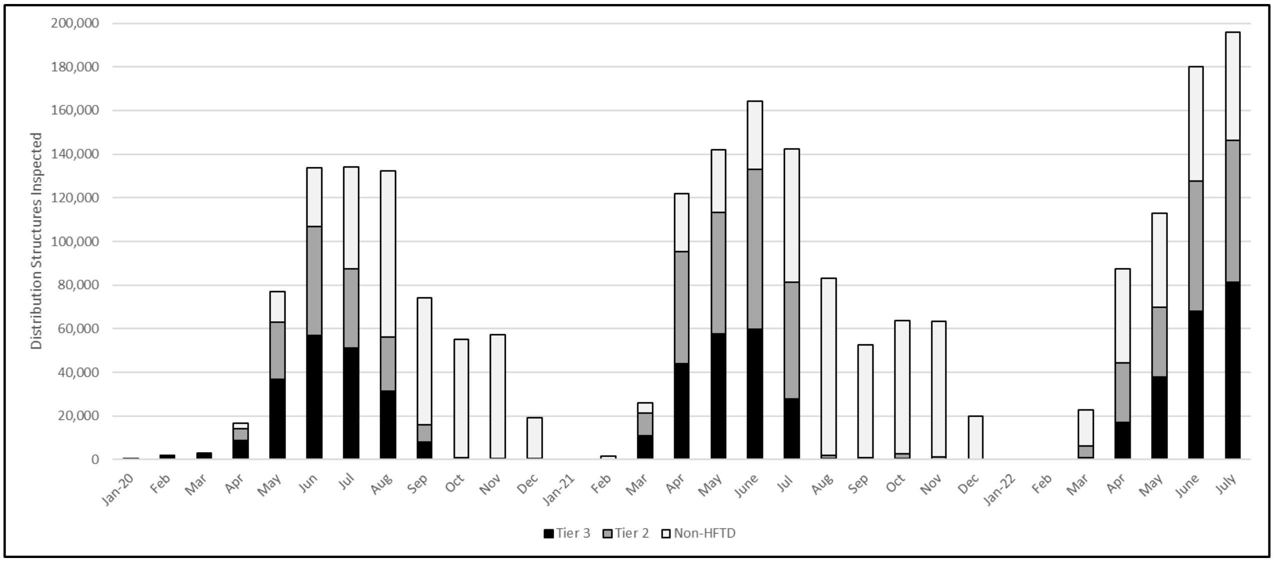

Figure 2. PG&E Distribution Structures Inspected (January 2020 – July 2022)[23]

The ISM was informed that the delayed start to inspections in 2020 was linked with a delay in finalizing the electronic application checklist tool that was being deployed among the inspectors in the field. Further delays, which resulted in the missing of the WMP target completion date in 2020, were due to work restrictions and other related impacts of the COVID-19 pandemic as it began to emerge in early 2020. Additional modifications were made to the checklists and the form of the field app at the start of 2021, which again led to a delayed start for that year. A rapid increase in the inspection volume during March-June allowed PG&E to achieve its target in 2021.

Calendar year 2022 again saw a slow start to the HFTD distribution inspections. For 2022, PG&E elected to switch from its historical use of multiple contractor companies to the engagement of one contractor company under a new, three-year contract, with two one-year extension possibilities. Reasons cited for this change include cost savings, reduced "Request for Proposals" management, and improved safety expectations and quality commitments. Delays in finalizing this new arrangement, combined with the introduction of the new centralized skills assessment and training program (previously described in the "Contractor Management" section of this report) and initial contractor availability due to out–of-state

[23] Internal PG&E Reports 2020, 2021, 2022 to 7/31. Includes inspection of structures; excludes tree connection inspections.

storm restoration redeployment, resulted in PG&E falling further behind its target inspections as the year progressed. PG&E management have indicated that with the single contracting company entering its second year, and with the contractor inspectors' previous training and skills assessment, the company should be able to begin its inspections much more actively starting in February of 2023. PG&E has also indicated that they are attempting to address issues experienced in the spring of 2022 related to contract inspectors moving to other projects.

In order to achieve its July 31 target date for 2022, PG&E's "Catch-Back" plan focused on significantly increasing the number of contract inspectors in the field in June and July, both from the new, solo contracting company, as well as from a second contracting company that began to assist on distribution inspections starting in mid-June. As seen in Figure 3, in order to complete its inspections by the target date, PG&E increased its weekly HFTD inspection volume from roughly 15,000/week in April to a peak of 40,000/week by mid-June.

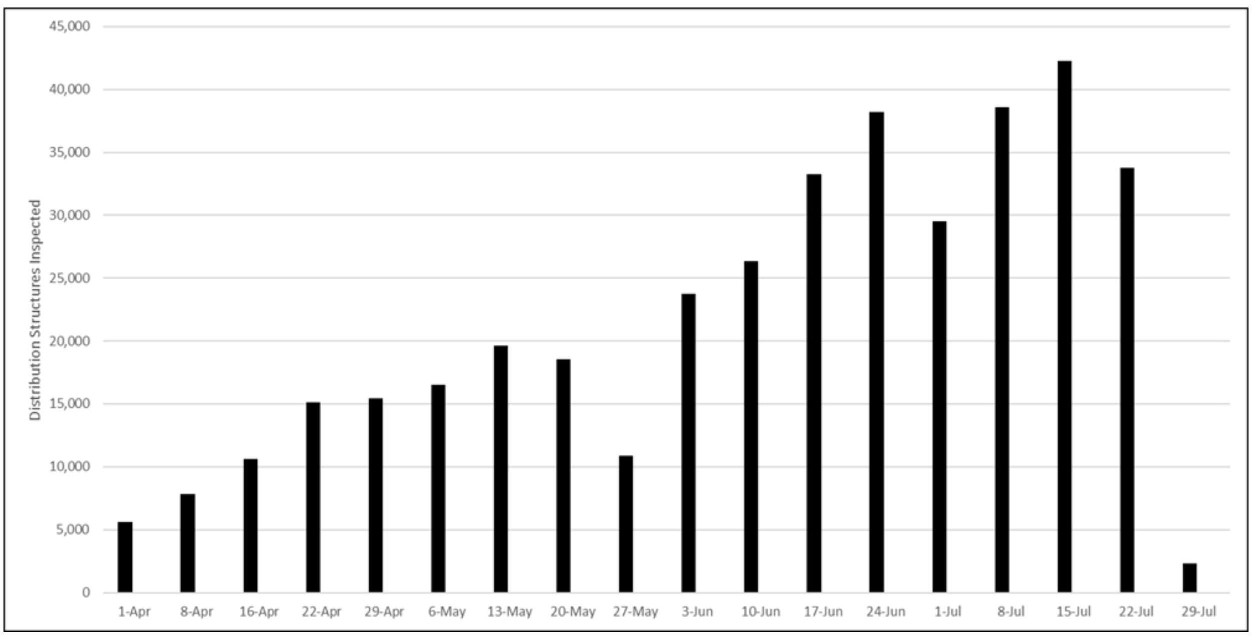

Figure 3. PG&E Tier 2 + Tier 3 Distribution Structures Inspected per Week (April to July 2022)[24]

As seen in Table 1, PG&E's employee inspector count remained relatively stable during the March to July 2022 period, whereas the number of contract inspectors that were conducting inspections in the HFTD areas roughly doubled from 188 in April to a peak of 374 in July.

[24]Internal PG&E Reports April 1, 2022 to 7/31. Includes inspection of structures; excludes tree connection inspections.

Table 1 PG&E Inspector Count - 2022[25]

Tier 2 + Tier 3 2022 Distribution Structures Inspected	March	April	May	June	July
Employee					
Inspectors Active in HFTD	67	84	77	85	90
Structures Inspected	5,854	9,940	8,906	13,526	11,946
Contractor					
Inspectors Active in HFTD	21	188	220	339	374
Structures Inspected	313	34,277	60,909	114,019	134,539

All Tiers 2022 Distribution Structures Inspected	March	April	May	June	July
Employee					
Inspectors Active in all Tiers	118	121	104	104	116
Structures Inspected	21,915	25,376	18,363	23,132	24,110
Contractor					
Inspectors Active in all Tiers	36	219	246	346	379
Structures Inspected	731	61,877	94,441	156,954	171,946

In addition to the increased number of contract inspectors, they were also working for longer days without interruption and were conducting more inspections per day than PG&E employees. One contractor, for example, conducted inspections every day from May 6, 2022, through July 30, 2022, without interruption. For the days those inspectors were in the field, the average number of structures inspected per inspection day, across all Tiers, averaged 21.3 for contractors and 14.9 for employees.

PG&E has stated that with contractors and employees both working on roughly equal 10-hour inspection shifts, the primary reason for the lower daily average inspection counts for the employees is likely that employees are allowed to do minor remediation work in the field for items identified during inspections, whereas the contractors are not. The ISM has also noted numerous inspectors who have been recording daily inspection counts well above the company-wide daily averages. While daily inspection counts may be expected to be higher in non-HFTD urban areas versus areas of more difficult terrain that may be found in HFTD areas, the ISM has observed individual contractor averages in July more than double the contractor daily average for that month in both HFTD and non-HFTD areas, with individual day inspection counts as high as 78 in a non-HFTD area and 68 in an HFTD area.

The ISM will be conducting further investigations into the quality of inspections of both the newly hired and trained inspectors. Such investigations will include: 1) examining the rate of defect notification and repair tag creation; 2) examining inspections records that have been flagged as having discrepancies or deficiencies; and 3) conducting ISM inspections of select distribution structures and comparing them against the records for inspections recently conducted by these groups.

[25] Internal PG&E Report March 1, 2022 to 7/31. Includes inspection of structures; excludes tree connection inspections.

During a 12-week period in 2022, ending on Week 26, PG&E conducted over 3,000 distribution field QC reviews. While PG&E had set an internal target of 65% of reviews achieving a perfect field review, the 3,000-plus field reviews averaged 43.5% achieving a perfect review. A separate quality verification of the distribution system inspections found that over a period from Week 14 to Week 23, 77.35% of the inspections received a pass rate. This again was below the internal target pass rate of 90%, which is the performance level linked to full payout for this metric under the management short term incentive plan. The ISM will continue to monitor PG&E's internal 2022 distribution field inspection QC program.

The most commonly occurring identification failures (many of which can lead to potential ignitions and wildfires) noted in this quality verification process relate to improper conductor splices, pole damage, missing/loose/damaged guy wires, exposed/broken/damaged grounds, service connections, missing inspection photos, incorrect tap clamp installations, damaged insulators and king pins, and damaged anchor rods.

Starting in 2023, PG&E has proposed new HFTD inspection cycles that will be based upon structures within circuit protection zones (separate segments within a circuit) that have been risk ranked using the company's latest Wildfire Distribution Model V3. The ISM will continue to monitor and analyze whether inspections are completed in a risk-informed manner.

Field Review of Inspections

For the period beginning in June 2022, the ISM performed an in-field review of PG&E's enhanced vegetation management work and electric distribution system inspections. The in-field review consisted of reviewing a sampling of the work performed by PG&E inspectors in PG&E's territory and reporting on observations found in the field not identified by PG&E inspectors.

Over a three-month period, the ISM reviewed approximately 500 electric distribution structures and over 200 miles of PG&E's EVM inspected circuits in HFTD areas which had been inspected by PG&E in 2022. The ISM's high-level observations include:

- <u>Electric distribution structures</u>: Of the structures inspected by PG&E and later reviewed by the ISM using PG&E's inspection checklist[26], at least one observation not previously identified by PG&E was found on approximately 30% of the structures. The top two observations missed by PG&E inspectors were 1) pole damage; and 2) conditions attributed to splices and improper conductor splices. This aligns with a few of the most commonly occurring identified failures found by PG&E's field QC review.

- <u>EVM circuits</u>: Observations were reported by the ISM to PG&E for trees considered 1) hazard trees (those that have a structural defect that makes them likely to fail in whole or in part[27], or are dead/dying and have the potential to strike PG&E facilities); 2) trees

[26] PG&E's inspection checklist covers structure, conductor, equipment, anchors and guys, hardware and framing, vegetation, and other required data type questions.
[27] https://www.fs.usda.gov/visit/know-before-you-go/hazard-trees

which did not have sufficient radial clearance per GO95 and PRC 4293; and 3) those that did not have sufficient overhead clearance based on PG&E's internal EVM standards.

In addition to the non-urgent observations reported to PG&E, as part of its standard process the ISM reports immediate hazards if conditions are discovered in the field which may require immediate attention. Two types of immediate hazard issues were identified and communicated by the ISM to PG&E during the reporting period. Those include: 1) exposed ground wire; and 2) trees with strike potential (those which, in their current state, have the potential to strike PG&E facilities if they fall).

VARIABILITY OF DISTRIBUTION RISK RANKING IN MODEL UPDATES

Over the past five years, PG&E's wildfire risk models have seen considerable refinement, incorporating such things as advanced machine learning, the introduction of increasing sources of historical ignitions, greater geographic granularity and environmental inputs, distance weighting, and the use of more advanced wildfire spread and consequence formulation over time. Figure 4 contains a summary of several of the key modeling changes that PG&E has been incorporating into its Wildfire Distribution Risk Models (WDRM) over time.

		2019 WDRM v1	2021 WDRM v2	2022 WDRM v3
Probability	Exposure	HTFD T2/3	HTFD T2/3	**Service Territory**
	GIS Vintage	2018	2020	**2022**
	Risk Event	2015-2018 Ignitions	2015-2019 Ignitions	**2015-2020 Outages / Ignitions / Damages**
	Vegetation	Yes	Yes	Yes
	▶ LiDAR Data	No	No	**Yes**
	Conductor	Primary	Primary	Primary and Secondary
	Support Structures	No	No	**Yes**
	Transformers	No	No	**Yes**
	Compositing	No	No	Yes
	Mitigation Effectiveness	No	No	Yes
Consequence	Exposure	HTFD T2/3	HTFD T2/3	**HTFD + Burnable T1**
	GIS Vintage	2016	2019	**2022**
	Fuels	2012 LANDFIRE	2020 Fuels Snapshot	**2030 Forecast Growth**
	Simulation Duration	6 Hours	8 Hours	8 Hours
	Consequence Formulation	Reax Index	FBI >=2 and Acres >= 300 and Buildings >= 50, OR FBI >=3	**FPI >= R4, OR FL >= 5 and ROS >= 12**

Figure 4. Summary of PG&E's Key Modeling Changes – 2019 through 2022[28,29]

While the wildfire model enhancements are allowing PG&E to better target its wildfire mitigation efforts to areas deemed higher in risk for wildfire (with the probability of ignition combined with the consequences of fire spread now modeled down to 100-meter pixels), the company has been seeing considerable variability in the risk ranking of its distribution circuits between each version of the model. With these large changes in circuit risk ranking, some of

[28] PG&E 2022 Wildfire Mitigation Plan Risk Modeling & Assessment presentation at an Energy Safety WMP Workshop, May 10, 2022

[29] FBI = Fire Burn Index; FPI = Fire Protection Index; FL = Flame Length; ROS = Rate of Spread

the earlier wildfire mitigation work that was prioritized based on earlier versions of the risk models now maps onto circuits and circuit protection zones (CPZ, also known as "circuit segments") that the latest version of the model is showing as having lower risk.

The other impact of such changes in risk ranking is that for mitigation activities with long lead times such as system hardening (where it may take several years to scope, estimate, and permit the work), by the time a project is ready for construction, the latest version of the risk model ranks these CPZs much lower than when they were originally selected for system hardening. This has led to PG&E having to consider abandoning and expensing certain pre-construction system hardening projects.[30]

PG&E's risk models, and the changes that have been made to them over time are described in detail in recent WMP reports and will not be addressed here. In this section, the ISM instead has focused its observations on the degree of variability in risk rankings between the latest two model versions, and the observations related to the impacts of these changes.

In terms of the wildfire risk model history, Figure 4 (above) highlights three versions of the WDRM. In addition to these three WDRM versions, PG&E also created the "Circuit Based Planning" model in between WDRM V1 and V2 in late 2019 which was used to prioritize the three-year Tier 2 distribution inspection cycle. As with the risk ranking variability seen between V1 and V2 of the models, where none of the top 100 circuit segments between the two models overlapped, this Circuit Based Planning model, which incorporated different modeling elements than V1 and V2, also saw significant variability in its circuit risk ranking from V1 and V2.

Some of the larger changes between the two models include: 1) the V1 risk results not being distance weighted, whereas V2 prioritization included a distance factor; 2) the use of a different wildfire spread model than what is currently in use among all of the large California utilities; 3) the incorporation of an egress score in V1 which was eliminated in later versions (but which may be re-introduced in later models); 4) updated fuels snapshot (from 2012 used in V1 to 2020 used in V2); and 5) the introduction of machine learning in V2 versus regression analysis and the use of differing dependent and independent variables for each of the V1 sub-models.

In April 2022, PG&E approved the use of the updated WDRM V3 risk model. In addition to the changes highlighted in Figure 4 (above), the WMP contains a detailed description of the new features incorporated into V3. After making the model modifications, a significant shifting of risk rankings has again occurred between the V2 and V3 models.

Figure 5 graphically presents the shifting of the risk ranking of the CPZs from V2 on the left-hand side to V3 on the right-hand side.

[30] Internal PG&E Presentation, June 2022

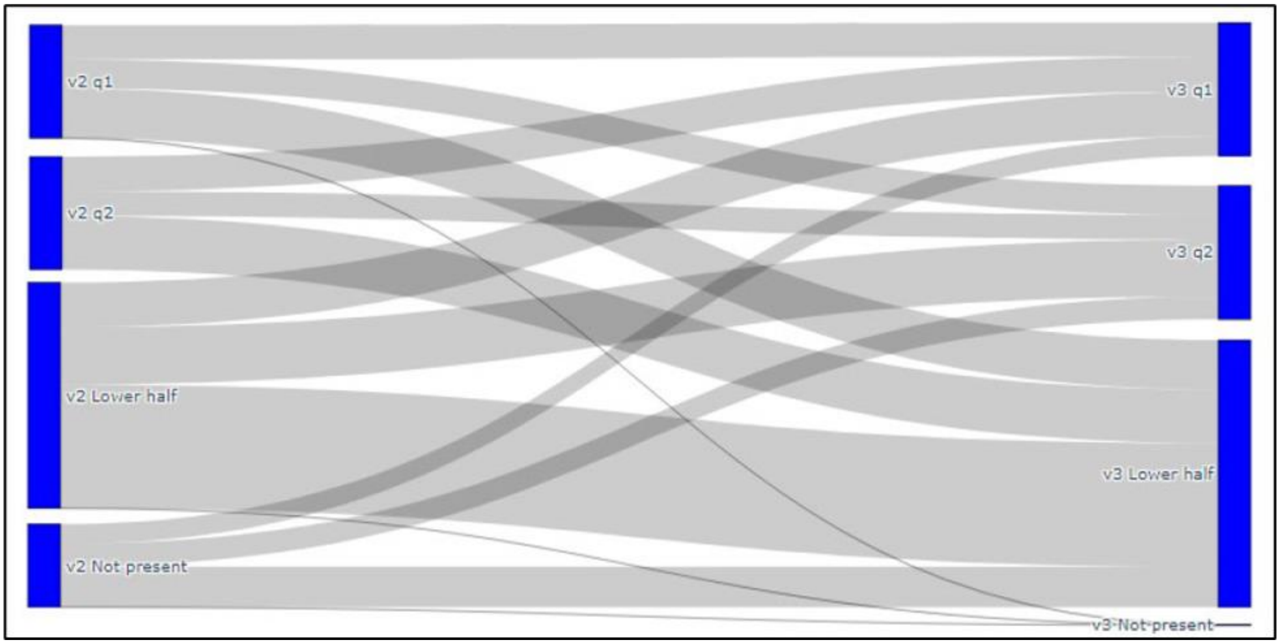

Figure 5. PG&E's Shifting of Risk Ranking of CPZs – V2 to V3[31]

As seen in this figure, there is again considerable shifting of the risk ranking of CPZs between the two models, with the top quartile of V2 being reallocated roughly equally now among the quartiles of V3. The section at the bottom of the left-hand side represents new CPZ's that were not present when the V2 model was created (due to additional sectionalization), but that are now included in the January 2022 CPZ vintages being used by V3. These new CPZ's are also seen to be allocated broadly across all quartiles in V3.

In presentations received by the ISM, PG&E's analysis shows that the majority of the CPZ risk rank shifting in WDRM V3 is due to larger changes in wildfire consequence scoring, versus more minor adjustments to the probability of ignition. While the overall predictive power of probability has dropped slightly from V2 (due in part to the inclusion of a greater number of lower-frequency, and more difficult to predict ignition drivers, including population-based ignition events involving third parties and animals), the change in consequences methodology now aligns V3 with the methodology used in PSPS wildfire consequences modeling, and the V3 risk curve is aligned with the PSPS consequence 10-year lookback. In addition, PG&E has represented that the V3 consequences model now aligns better with public safety specialist risk scoring and uses a 2030 projected fuel layer to better simulate vegetation regrowth in fire scar areas.

Since the wildfire mitigation work plans for EVM and system hardening for 2021 and 2022 have been focused on working on CPZs at the top of the V2 risk ranking, some of this completed and still in-progress work has/is continuing to be done on CPZs that the latest model has now identified as lower risk. For the WMP EVM programs, work in 2021 was primarily focused on CPZs risk ranked 1 to 100 using a tree-weighted adjustment (as detailed in the WMP) to the V2 model. For 2022, the EVM work is focusing primarily on CPZs ranked using same model from

[31] Internal PG&E Presentation, April 2022

101-253. Given annual work plan horizons, and the approval of V3 of the model in April 2022, the first EVM, system hardening and distribution inspection work plans that are anticipated to be risk informed by V3, are not scheduled to begin until 2023.

As previously noted, system hardening projects can take years between when they are initially scoped, and when construction may begin. During such an extended period, changes to the risk models have been occurring, with accompanying shifts in CPZ risk rankings. As a result of these changes, previously approved system hardening projects have not yet initiated construction on CPZs that are now ranked as much lower risk.

With the release of V2 in late 2020, PG&E directed the reprioritization of the System Hardening Program, halting many projects and placing them on-hold pending reevaluation. Throughout 2020 and 2021, these projects were reevaluated, and many were brought back into the workplan for reasons such as EPSS Recommendations, CalTrans Design Standard Decision Document pilot, and PSPS lookback changes. PG&E elected to hold and wait until the release of V3 to complete the final opportunity assessment and then decide whether to cancel several projects scheduled to occur on CPZs now deemed lower risk.

The shifting of the distribution circuit/CPZ risk rankings between model versions over the past five years also has the unintended consequence of making it appear as if much of the previous EVM and system hardening work was focused on areas now forecast to have lower risk.

Figure 6 provides an example, indicating the 2022 system hardening miles (excluding fire rebuild miles) overlain with the V3 system hardening composite cumulative risk scores by CPZ. As seen in this figure, the system hardening miles in the current year appear to be spread across a large range of V3 risk ranked CPZs.

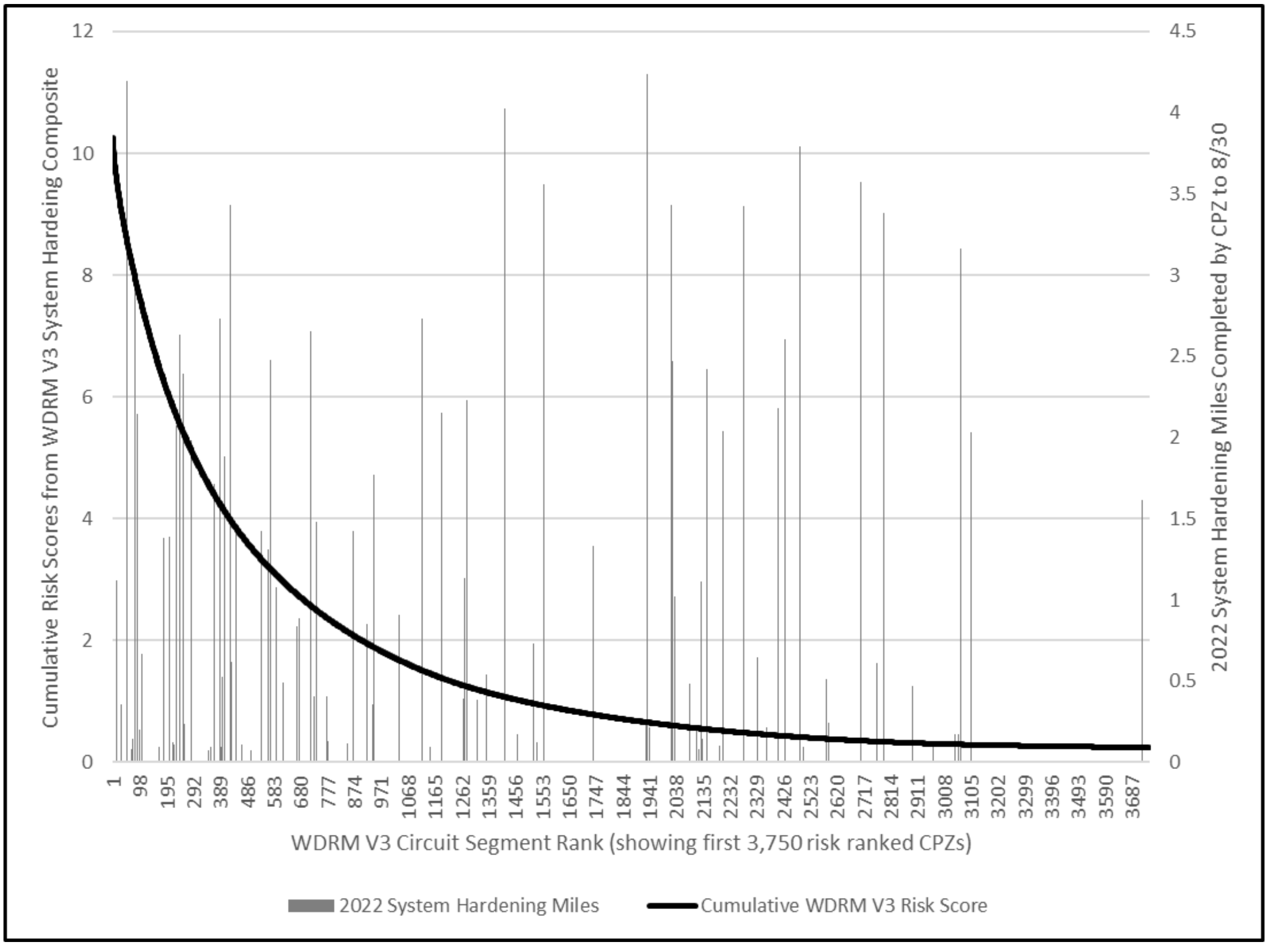

Figure 6. WDRM V3 Cumulative Risk Score Overlaid with 2022 System Hardening Miles [32]

GAS OPERATIONS OBSERVATIONS

PG&E is the owner and operator of one of the largest natural gas systems in the United States. PG&E is responsible for an integrated transmission, storage and distribution system comprised of over 6,000 miles of backbone and local transmission pipeline, three gas storage facilities and over 40,000 miles of distribution pipeline.

PG&E's gas operations have been under significant external oversight and scrutiny since the San Bruno pipeline explosion in 2010. During the period of heightened regulatory oversight, PG&E was required to change and/or implement several policies, programs, and processes related to enhancing gas operations and increasing public safety. The ISM is performing various monitoring activities related to the status of the programs.

[32] Internal PG&E Reports (April 2022 and August 2022)

GAS STORAGE OPERATIONS

During the reporting period, the ISM 1) performed interviews of leadership and personnel within gas operations related to gas storage; 2) attended various gas operational meetings; 3) performed site visits to each of PG&E's three gas storage facilities (Pleasant Creek, Los Medanos, and McDonald Island); 4) reviewed PG&E's gas related risk models, procedures, and programs; and 5) completed various analyses associated with gas operations.

PG&E has indicated that the gas storage asset group has identified issues with resource availability, including internal staffing and vendor availability. Regarding internal staffing, in 2021, gas storage operations requested the addition of 16 employees; however, due to attrition, recruiting difficulties, and an internal process for review of staffing for critical positions, gas storage operations currently has only one more employee than they had at the time of the request. Additionally, constrained internal staffing has led to a delay in implementing its gas storage employee training program. With the recent leadership change in Gas Operations (see Core Leadership Changes section), PG&E is reviewing the gas operation's organizational structure, budget, and headcount to determine appropriate mitigation measures. The ISM will monitor and review the impacts of the training program delay as well as the mitigation measures implemented.

Regarding vendor availability, PG&E has indicated that there is a scarcity of rigs with qualified crews in California to perform the well work that is required by PHMSA/CalGEM regulations. Due to increased competition for qualified rig crews as a result of high oil prices, many rigs and the associated crews are choosing to service conventional oil and gas operations in other states. The service companies' decisions to work in other states and on conventional oil and gas operations makes it difficult for storage operators to support a high frequency schedule of storage well work.

Based on communications with CalGEM and PG&E's General Rate Case, PG&E submitted a plan which accelerated its base well conversion work plan from 2025 to 2024. On June 15, 2021, CalGEM issued a letter to PG&E which PG&E refers to as the Revised Implementation Plan. According to PG&E, this plan affirmed PG&E's acceleration of its base well conversion work plan to inspect and convert wells with tubing and packer equipment through 2024 and confirmed the requirement to perform incremental pressure testing of converted wells on a 24-month interval.

The underground natural gas storage inspection regulations provide several key review and determination decision requirements by CalGEM as follows:

> *"Pressure testing of the production casing shall be conducted at a minimum frequency determined on a well-by-well basis under Section 1726.3, subdivision (d)(3), provided that the well-specific minimum pressure testing frequency has been reviewed and approved by the Division. If the Division has not approved a well-specific minimum pressure testing frequency for a well as part of the Risk Management Plan, then the operator shall pressure*

test the well at least once every 24 months."[33]

PG&E has stated they are waiting for guidance regarding modification of CalGEM's well-by-well 24-month schedule for storage well direct casing inspection and pressure testing. Until such determination, PG&E is scheduling service equipment to perform 24-month direct casing inspection and pressure testing for all gas storage wells per current CalGEM requirements. The ISM has not yet determined whether all information required for CalGEM to consider a modification of the 24-month schedule has been submitted by PG&E to make such determination.

In order to pressure test a well that has not yet been converted to tubing/packer configuration, a rig must be moved onto the well to set either a packer or a casing plug in order to isolate the casing/tubing annulus for pressure testing. Since PG&E is required to convert all wells to tubing and packer operation, they have elected to perform the pressure tests and a direct casing inspection (while there is no tubing or packer in the wellbore) at the same time a well is being converted.

According to PG&E, rig operations are required to perform either a) a storage well conversion or b) a converted storage well direct casing inspection (that requires temporary removal of the tubing and packer from the wellbore). During rig operations, the close proximity of storage wellheads requires four offset storage wells to be shut-in during rig operations (two on either side of the well to be serviced by a rig) including removing their storage flow lines. This offset storage well shut-in period begins approximately one week before the rig operation and lasts up to two weeks afterward. Having a total of five wells out of service for each rig operation has the potential to impact the number of wells available to support customer supply and demand, especially during annual peak supply and demand periods.

Per CalGEM, after a gas storage well has been converted to tubing/packer configuration, the gas storage well can be pressure tested without requiring rig operations, therefore the adjacent storage wells are not required to be taken out of service.

During the reporting period, CalGEM performed an inspection of PG&E's three gas storage facilities (Pleasant Creek, Los Medanos and McDonald Island). Inspection results have not yet been officially issued by PHMSA. However, the ISM has reviewed a list provided by PG&E's internal audit department of responses to questions from the inspection with which CalGEM was not satisfied. Many of the concerns are related to the inadequacy of procedures and records, and these concerns will need to be addressed. The ISM will continue to monitor PG&E's actions associated with these issues.

PIPELINE INTEGRITY MANAGEMENT

The Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP), and Gas Safety Plan all incorporate aspects of PG&E's Pipeline

[33] Requirements for California Underground Gas Storage Projects. California Code of Regulations, Title 14, Chapter 4. Development, Regulation, and Conservation of Oil and Gas Resources.

Integrity Program. During the period, the ISM: 1) performed interviews of gas leadership and personnel related to pipeline integrity practices being implemented by PG&E; 2) attended various gas operational meetings; 3) performed a site visit to observe in-line pipeline integrity inspections; 4) reviewed PG&E's gas related risk models, procedures, and programs; and 5) completed various analyses associated with gas operations.

During the site visit held during this period, the ISM observed in-line pipeline integrity testing on the gas line running between San Andreas Substation to Healy Substation. The inspection testing performed during the site visit included a visual inspection of the interior of the pipeline utilizing a camera and laser deformation sensor testing to determine potential metal loss, dents, or other anomalies associated with the shape of the pipe. Magnetic Flux Leakage (MFL) testing was not a part of this inspection testing performed during the site visit on this section of pipeline. However, PG&E indicated that MFL testing is scheduled to be performed at a later date with traditional in-line testing equipment. A final report regarding the testing performed on the gas line running between San Andreas Substation to Healy Substation was not available before the conclusion of the site visit. The ISM will continue to monitor certain activities associated with PG&E's gas operations and observe additional pipeline integrity testing.

GAS OPERATIONS RECORDKEEPING AND RECORD MANAGEMENT

PG&E has indicated there is a high risk of potentially large volumes of overdue "Can't Get In" (CGI) tickets in the near future. The anticipated increase in volume is the result of several compounding factors, including 1) COVID-19 and other health related concerns driving increased customer refusals for access; 2) budget constraints lowering staff volumes available to perform the work; 3) decreased effectiveness of customer communication; and 4) expiration of the M-4845 waiver (discussed in more detail below). PG&E has indicated that the number of overdue CGIs remained low in 2021, however that was driven by the exclusion of CGIs allowed under the M-4845 waiver. With the expiration of this waiver in December 2022, the number of overdue CGIs could increase to more than 30,000.

PG&E identified a problem with CGIs related to record-errors in 2020 and implemented changes to address the issues. At the time, there was no link between the mapping system and the customer meter database, and there was a significant backlog of mapping corrections with thousands of corrections submitted each year. PG&E implemented several changes to address these issues, including: 1) standardization and training; 2) tracking atmospheric corrosion inspection errors and leak survey errors in an Abnormal Operating Condition (AOC) bucket; and 3) using trained error resolution Subject Matter Experts to take over tracking and resolution of errors. These changes led to significant improvements in CGIs related to record errors, but PG&E continues to strive for further improvement.

In 2020, the CPUC issued the M-4845 waiver, which acknowledged that the COVID-19 pandemic significantly challenged PG&E's ability to complete work execution. This further allowed for exclusion of CGIs that were not completed ahead of their original compliance dates from the overdue CGI population. The COVID-19 pandemic and a moratorium on service disconnection has negatively affected the completion of CGIs resulting in an increased backlog. If not for the M-4845 waiver, there would have been significantly more overdue CGIs in 2021 and 2022. The M-4845 waiver will expire in December 2022, and the SED (Safety and Enforcement Division) has given until the end of 2022 for all 2021 backlogs to be completed, which PG&E has indicated creates a high risk of a large number of overdue CGIs in 2023.

PG&E has made efforts to address the risk of a high number of CGIs in 2023, including:

- Increase customer communication and education, including standard communication (phone call, emails, text messages); also produced a new brochure explaining gas meter safety, and promotion of the pge.com website meter safety inspection page to educate customers;

- Completed the Accurate Reconciliation of Meters and Service Project in Q3 2021, which should reduce the volume of errored records required NRT review; and

- Continued weekly dialog between the CGI team, NRT, and Leak Survey teams to track progress.

EMERGING OBSERVATIONS

In addition to the areas covered in this initial report, the ISM will continue to perform activities and monitor developments in areas such as vegetation management, enhanced vegetation management, sourcing of materials and labor to support PG&E's 10K electrical system undergrounding initiatives.