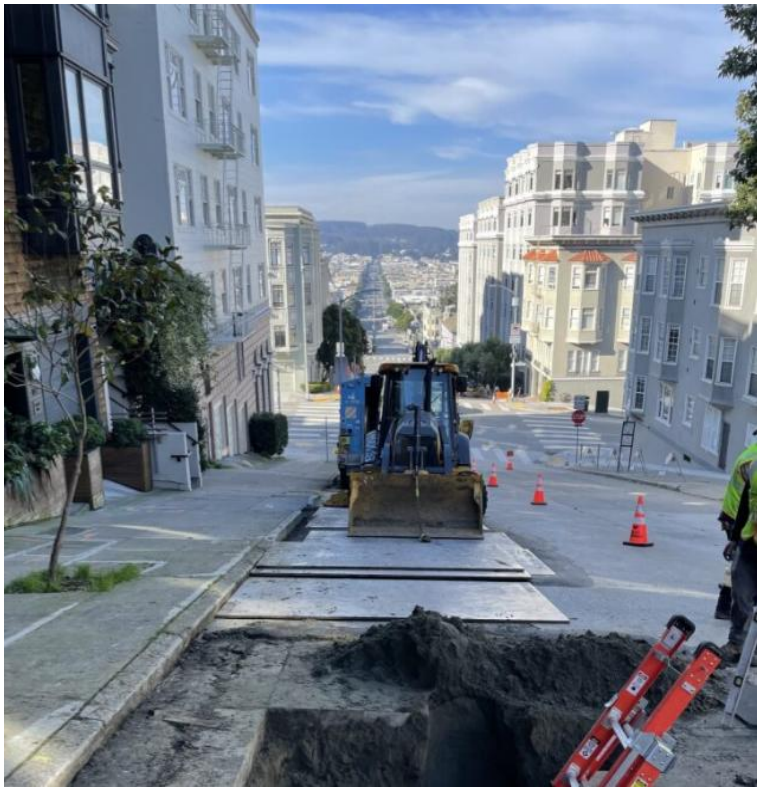
Pacific Gas and Electric Company®

2026 GAS SAFETY PLAN



March 13, 2026

Dear Reader,

PG&E has a critical responsibility to design, construct, maintain, and operate our gas systems in a manner to keep customers, communities, and coworkers safe. The 2026 Gas Safety Plan ("Plan")[1] provides a thorough summary of the work we accomplished in 2025 and highlights the meaningful progress we have made in strengthening gas safety and operational excellence.[2] Our goal is to present this information clearly and accessibly for a broad audience while demonstrating our continued commitment to transparency and improvement.

PG&E's 2026 Plan reflects how Gas has advanced safety excellence across the system. Throughout the document, we describe the ways in which Gas has grounded our work in PG&E's True North Strategy and applied the Performance Playbook to improve engagement, streamline work, and strengthen the communication from the frontline to senior leadership. The Plan also outlines how Gas completed its transition to the PG&E Safety Management Excellence System (PSEMS) in 2025, aligning Gas, Electric, and Power Generation under one enterprise safety management system that is based on national and international industry standards. PSEMS now serves as the foundation for driving operational excellence, safety performance, and reliability across the company.

The Plan contains updates on key metrics and improvements from 2025. This includes: An average response time of 19.8 minutes in handling gas odor calls, surpassing the target of 20.1 minutes; Strong performance in preventing third party dig-ins, achieving 0.80 dig in's per 1,000 tickets against a target of 1.03 dig-in's, supporting over 1.6 million USA tickets processed and 470 contractor workshops delivered; Continued progress in integrity management including 549.36 miles inspected in 2025, 113.14 of which were inspected for the first time, piggability increasing to 58.85% of the system and completed 100% of planned strength testing for the year; Faster mitigation of Grade 2 open leaks averaging 104 days, significantly outperforming the target of 150 days; and Substantial reductions in methane emissions by 52% compared to the 2015 baseline.

In 2025, PG&E Gas maintained compliance with ISO 55001 for asset management and complied with API RP 1173 for pipeline safety and API RP 754 for process safety, as validated through independent third-party audits conducted by LRQA. These certifications continue to reinforce our operational discipline, strengthen safety and compliance, and enhance operational efficiency and stakeholder confidence. We also expanded our Human Performance and Safety Culture initiatives, delivering 57 workshops, reaching over 1,000 Gas coworkers and growing our Gas Safety Culture Village teams and tools. Our Occupational Safety and Health Administration (OSHA) recordable rate improved by 8.6% in 2025 and we conducted 12 hands on emergency and de-escalation drills. These actions further demonstrate our commitment to public and coworker safety.

While we are proud of the progress detailed in this Plan, we recognize that safety excellence is a continuous journey. We remain focused and dedicated to strengthening our systems, processes, and culture, so every coworker goes home safely, every customer is protected, and every community we serve can rely on the integrity of our infrastructure. PG&E remains focused and dedicated to ensuring everyone and everything is always safe.

Sally Romero

Sally Romero
Senior Vice President | Gas Transmission & Distribution
Pacific Gas and Electric Company

Austin Hastings
Vice President | Gas Engineering
Pacific Gas and Electric Company

[1] PG&E submits this plan in accordance with General Order 112-F Section 123.2(k), and Public Utilities Code §§961 and 963.

[2] This Plan also incorporates PG&E's biennial Leak Abatement Plan.

PACIFIC GAS AND ELECTRIC COMPANY
GAS SAFETY PLAN

TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

TABLE OF CONTENTS (CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
GAS SAFETY PLAN

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E or the Company or the Utility) continuously strives to provide safe transport of natural gas under pressure through approximately 5,650 miles of transmission pipeline, approximately 45,400 miles of gas distribution main pipeline and approximately 4.8 million customer meters, 4,400 transmission and distribution (T&D) regulator stations and regulator sets, eight compressor stations,[1] and three gas storage facilities.[2] The PG&E natural gas system spans from the California and Oregon border in the north to the California and Arizona border in the south, and from the west coast of the Pacific Ocean to the Sierra Nevada mountains in the east, serving approximately sixteen million Californians. Our employees work around the clock, 365 days a year, on a mission to provide both reliable service and to keep everyone and everything always safe.

PG&E's Gas Safety Plan (Plan) provides a view into the safety activities and processes PG&E practices every day. It demonstrates and reflects on the specific gas safety work that was accomplished in 2025. PG&E annually reviews and updates its Plan in accordance with General Order (GO) 112-F Section 123.2(k) and Public Utilities Code (Pub. Util. Code) Sections 961 and 963.[3] Figure 1, below, provides a summary of PG&E's performance in key areas.

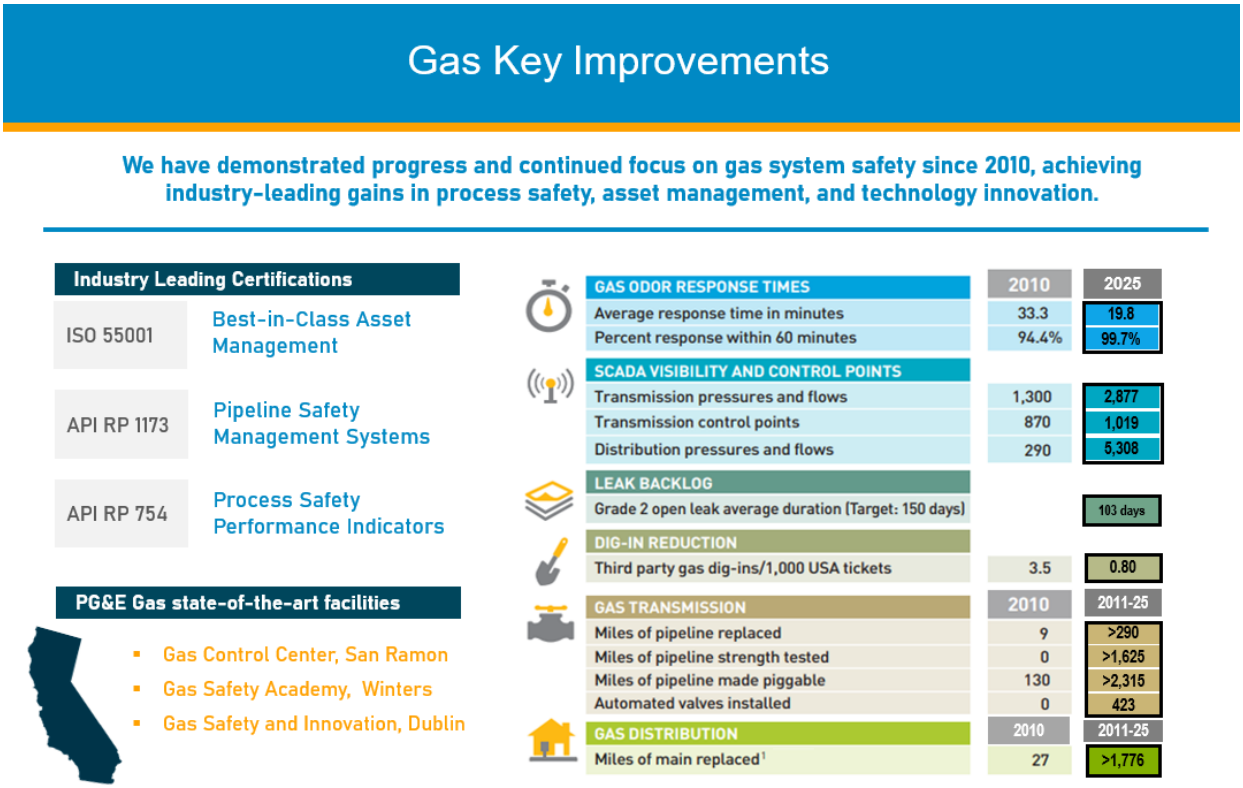


Figure 1 – Gas Key Improvements

1. STRUCTURE OF THE GAS SAFETY PLAN

The 2026 Plan reflects on work performed in 2025. In alignment with California's regulatory framework,[4] this Plan explains how PG&E places a top priority on the safety of the public, customers, employees, and contractors. It also summarizes how the Company has made safety investments in processes and infrastructure that are consistent with best practices in the gas industry.

The following sections of the Plan provide additional information on how PG&E is achieving Gas Safety Excellence and our Gas Stand to be the safest and most reliable gas utility while creating an affordable, carbon-neutral gas system. The Plan includes updates on the Company's safety goals and commitments to public, customer, employee, and contractor safety.

- **True North Strategy:** PG&E's True North Strategy is a ten-year enterprise strategy that provides a clear vision of what it means to achieve the purpose of delivering for our hometowns, serving our planet, and leading with love. PG&E's True North Strategy sets the tone for the Company to focus on people, the planet, and prosperity. It showcases where the Company is headed and how it will get there.
- **PG&E Safety Excellence Management System (PSEMS):** The PSEMS is a PG&E-wide integrated safety management system based on national and international industry standards. It grants the framework and structure to drive operational excellence, safety, and reliability performance across PG&E.
- **Safety Culture:** This section highlights how PG&E continuously improves workforce safety through a culture focused on employees and building a deeper partnership between Gas leadership, Grassroots Safety Teams, and the Labor Unions.
- **Process Safety:** This section focuses on PG&E's efforts to prevent low frequency, high-consequence incidents, and how the Company mitigates consequences from these incidents.
- **Asset Management:** This section explains how PG&E Gas utilizes the Asset Management System and the principles of the ISO 55001:2024 standard for asset management systems. ISO 55001 specifies the requirements for establishing, implementing, maintaining, and improving a gas asset management system. Key concepts include understanding the condition of assets, assessing risks to those assets, implementing risk reduction strategies, maintaining asset condition and performance, and balancing cost, risk, and performance to achieve strategic asset management objectives.
- **Workforce and Compliance Framework:** This section reviews how PG&E qualifies, trains, and engages employee resources to mitigate risk by performing work on assets safely and correctly.
- **Continuous Improvement (CI):** This section showcases PG&E's efforts to cross-functionally continuously improve processes and procedures.

2. PG&E's True North Strategy

PG&E's True North Strategy represents where the Company is headed and the path to get there. It is PG&E's 10-year enterprise strategy that sets a clear vision of what it means to achieve our Purpose, which is to deliver for our hometowns, serve our planet, and lead with love. PG&E's True North Strategy is reflected throughout every coworker's day-to-day work and is integrated into our enterprise planning processes over time.

PG&E's Gas Transmission and Distribution (Gas T&D) and Gas Engineering departments (together, PG&E Gas or Gas) follow the Company's Business Plan Deployment model to set annual goals and initiatives. This process incorporates the Company's True North Strategy to create "Plans on a Page." Plans on a Page are summaries of annual plans that align strategic goals and initiatives from the Enterprise's direction and priorities to each functional area's key activities to achieve the Enterprise plan. The Gas functional area's Plans on a Page include both operational and engineering activities that align with the Company's focus areas: Safety, Quality, Delivery, Cost, and Morale. These plans drive action throughout the business. Related goals and metrics cascade down through each functional area to provide all coworkers with a line of sight into how their daily contributions support PG&E's True North Strategy.

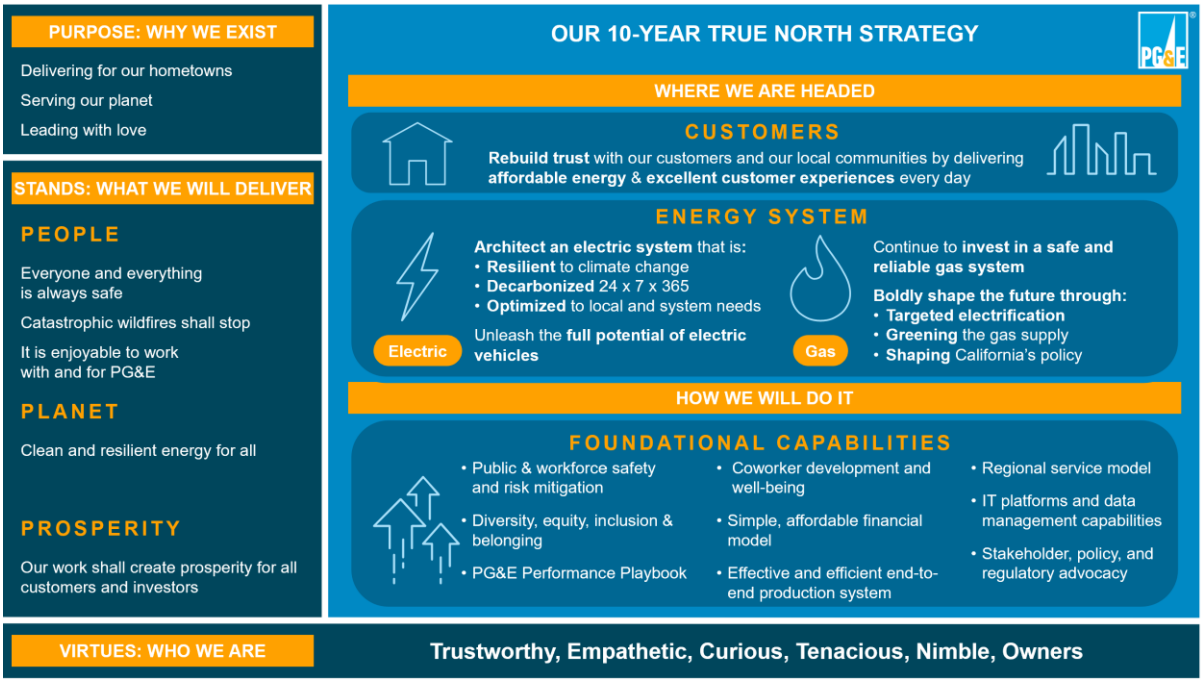


Figure 2 – PG&E's True North Strategy

3. THE PG&E SAFETY EXCELLENCE MANAGEMENT SYSTEM (PSEMS)

The journey to implement the Gas Safety Excellence Framework, grounded in the pillars of Asset Management, Safety Culture, and Process Safety, began in 2012. This Framework enabled PG&E Gas to develop management systems that established processes and controls to enhance asset lifecycle management and pipeline safety. Each pillar was underpinned by industry standards, with independent third-party certification strengthening the adoption of best practices in asset management, pipeline safety, safety culture, and process safety.

Figure 3 – PG&E Safety Excellence Management System Elements

The Framework led to the development and implementation of the Gas Safety Excellence Management System (GSEMS) in 2019. The GSEMS integrated the requirements of foundational standards—ISO 55001 (2014 edition) for Asset Management, API RP 1173 (2015 edition) for Pipeline Safety Management Systems and API RP 754 for Process Safety Performance Indicators (2021 edition)—into a single, comprehensive management system to improve system maturity.

The successful implementation of the GSEMS served as a model for the development of a PG&E-wide safety excellence management system in 2022. In 2023, the PSEMS manual was published. The PSEMS integrates the requirements of the three foundational standards for the GSEMS and ISO 45001 Occupational Health and Safety Management System Requirements into a framework consisting of 13 management system elements. In 2023, the GSEMS was retired as the PSEMS became the integrated safety management system standard across PG&E. In 2024, PG&E Gas completed the transition to the PSEMS. The transition included retirement of the Gas Management of Change (MOC) Standard and transition to the PG&E MOC standard, aligning Gas, Electric and Power Generation to a common standard. In 2025, PG&E Gas transitioned to the Pipeline Safety Management System (PSMS) Maturity Assessment model, which introduced a structured annual assessment cycle focused on specific management system elements, prioritized by risk. The model uses a maturity scale ranging from Level 1 (Initial) to Level 5 (Optimized).

a) Gas Independent Third-Party Certification to Industry Standards

PG&E Gas demonstrates its commitment to safety, reliability, and operational excellence through the maintenance of independent third-party certifications aligned with internationally recognized industry standards, including ISO 55001 for asset management systems, API Recommended Practice 1173 (API RP 1173) for pipeline safety management systems, and API Recommended Practice 754 (API RP 754) for process safety performance indicators. Together, these standards provide a comprehensive framework for asset management, pipeline safety, and the monitoring and improvement of process safety performance across Gas Operations.

ISO 55001 establishes best practices for managing physical assets throughout their lifecycle to optimize performance and reduce risk. API RP 1173 defines a structured approach to pipeline safety grounded in leadership commitment, risk management, and continuous improvement, while API RP 754 establishes leading and lagging indicators used to measure, evaluate, and strengthen process safety performance. Ongoing conformance with these standards is validated through rigorous audits conducted by accredited independent third-party auditors.

Consistent with its post–San Bruno emphasis on independent validation against leading industry standards, PG&E Gas completed its eleventh consecutive year of sustained certification in 2025. As part of this effort, LRQA (formerly Lloyd's Register Quality Assurance) conducted comprehensive surveillance audits in April and September 2025, covering PG&E Gas T&D and Gas Engineering. Audit activities included reviews of field work, station operations, asset management practices, and pipeline safety management processes across the PG&E service territory, including Eureka, Redding, Chico, Oroville, Oakland, San Francisco, San Jose, the Burney Compressor Station, and the Los Medanos Storage Facility. The audits concluded with reviews of corrective actions taken to address identified findings and opportunities for improvement from prior audits.

Collectively, the 2025 audit activities confirmed continued conformance with ISO 55001, API RP 1173, and API RP 754, with a single minor nonconformance identified related to contractor safety practices during a service transfer. LRQA auditors also recognized several organizational strengths, including effective field-level hazard identification, strong mentoring of newer workers, consistent use of the Energy Wheel/Keys to Life, and improved tracking of Operator Qualification (OQ) credentials in the field.

In addition, LRQA identified opportunities to further strengthen operational reliability and safety performance. These included enhancing excavation edge protection, improving plastic pipe coil securement to prevent injuries, aligning paper and digital maintenance records at storage facilities, updating well relief plans last revised in 2016, and ensuring consistent adoption of revised leak testing procedures. Continued emphasis on contractor oversight, calibration data quality, and management

review processes will support sustained improvement and reinforce readiness heading into the next LRQA surveillance audit scheduled for early 2026.

b) Safety Management System Maturity

PG&E Gas began conducting biennial assessments to evaluate the maturity of its safety management system in 2019. These internal evaluations have identified more than 150 opportunities for improvement. Examples include enhancements to emergency response capabilities, improvements in natural gas system integrity, and strengthened controls for occupational health, safety, and process safety. Results of the 2025 Gas PSEMS maturity assessment are shown in Figure 4.

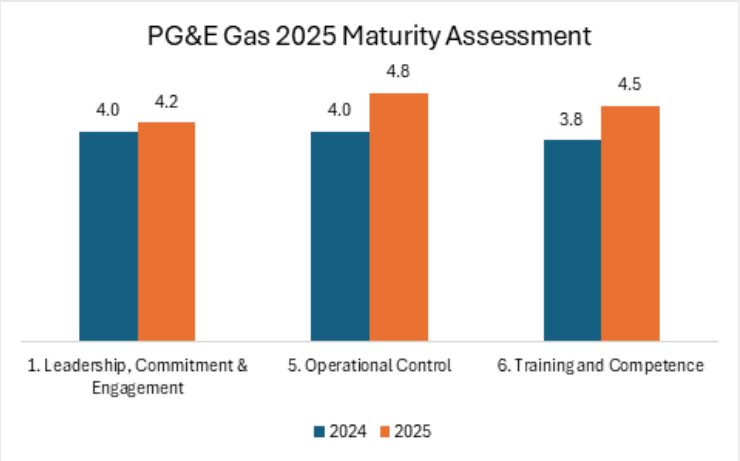


Figure 4 – PSEMS Maturity Assessment Results

4. Public Safety

As mentioned in the Introduction and shown in Figure 1, PG&E continues to make progress and improvements to support the safe operation of the gas system. Areas of continued focus to improve public safety are In-Line Inspections, Third Party Dig-ins, Gas Emergency Response, and Strength Testing. The 2025 metrics for those areas of focus can be found in the bullets below.

- **In-Line Inspections:** In 2025, PG&E increased piggability from 58.09 percent to roughly 60.55 percent of the approximately 5,496 miles of the Gas Transmission system.[5]
- **Third-Party Dig-Ins:** In 2025, PG&E experienced 0.80 third-party dig-ins per 1,000 Underground Service Alert (USA) tickets, exceeding the 2025 target of 1.03 third-party dig-ins per 1,000 tickets.
- **Gas Emergency Response:** In 2025, PG&E's average response time for immediate response gas odor or gas leak calls was 19.8 minutes, exceeding the target of 20.1 minutes.
- **Strength Test:** In 2025, PG&E completed strength-testing of 2.78 miles of pipeline, completing 100 percent of the planned mileage for the year.[6]

5. WORKFORCE SAFETY

PG&E's goal is to continually reduce risk to keep customers, communities, and workforce (employees and contractors) safe. PG&E focuses on building an organization in which every work activity is designed to facilitate safe performance, every member of the workforce knows and practices safe behaviors, and every individual is encouraged to speak up if they see unsafe or risky behavior with the confidence that concerns and ideas will be heard and follow up actions will be taken.

PG&E aspires to eliminate workplace fatalities and to reduce the number of serious safety incidents. PG&E established Days Away, Restricted or Transferred (DART) targets for 2025, with the goal to have a reduction from 2024. In 2025, Gas had 87 DART cases at a rate of 1.66 per 100 coworkers. This was an increase of 28 cases and a rate increase of 0.16, or 47 percent from 2024. The top three DART injuries were related to Sprains/Strains, Musculoskeletal, and cuts/lacerations, with Sprain/Strain accounting for 63 percent of all DART cases. Throughout 2025, Gas utilized problem solving sessions to target containment and countermeasures in reducing the top incident drivers. One major action resulting from these efforts was the adoption of reciprocating saws for stuck collars on gas meter sets. This adoption is expected to reduce the number of ergonomic injuries related to manual wrenching.

Gas employees were involved in 39 Lost Time Injuries in 2025, resulting in an increase of five cases compared to 2024. During the same period, the California Occupational Safety and Health Administration (OSHA) recordable rate decreased by approximately 8.6 percent from 2.97 percent in 2024 to 2.71 percent. The utilization of PG&E's 24 hour, seven days a week Nurse Care Line (NCL), early reporting, and early intervention with Industrial Athlete (IA) utilization all added to the reduction. In 2025, 91.8 percent of employees who called the NCL reported discomfort, or an injury, within 24 hours. This was a 2.1 percent increase from 2024, as seen in the table below.

PG&E believes that encouraging employees to speak to healthcare professionals about injuries or illnesses within 24 hours contributes to reduced severity and recovery time of injuries or illnesses. Through consistent application of timely reporting and preventative efforts, the serious Lost Time Injuries have begun to follow the OSHA recordable curve and show improvement.

Table 1 – Gas - NCL Timely Reporting

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Percentage Total	69.5	74.0%	77.7	80.8%	75.5	75.9%	92.8%	90.7%	90.1%	91.8%

In 2025, Gas T&D closed the year at 1,108 days without a Gas coworker or contractor fatality. During the year, Gas T&D experienced one non-fatal Serious Injury and Fatality Actual (SIF-A) incident and two safety incidents with Serious Injury and Fatality Potential (SIF-P). The SIF-A was related to a catwalk collapse at a compressor station. One SIF-P incident involved a concrete wall collapse, and in the second SIF-P incident, a high head extension blew off and injured a coworker.

To address these incidents, Gas T&D implemented numerous corrective actions, including reviewing and updating applicable procedures, field guides and design standards; developing new inspection processes; and creating videos to share incident information and learnings. Additional corrective actions included the use of audible devices and multiple spotters when backing in close quarter or high hazard situations.

In addition, PG&E's Gas Safety Improvement Strategy continued to emphasize the use of the Hazardous Energy Wheel (Figure 5), revised the Job Site Safety Analysis (JSSA), and focused on building capacity to fail safe into our high-risk work activities. Gas T&D also continued to reinforce Human Performance Standards by engaging almost 1600 Gas employees across 57 trainings and workshops across all Gas functional areas. Collectively, these activities helped Gas T&D maintain a low number of Serious Injury or Fatality Potential (SIF-P) events.

In 2025, PG&E continued its adoption of Edison Electric International's (EEI) Safety Classification Learning Model (SCL) to classify its serious injury or fatality (SIF) incidents. The EEI SCL model classifies incidents into the following categories: High-Energy SIF (HSIF), Low-Energy SIF, Potential SIF, Capacity, Exposure, and Success & Low Severity. Adopting the EEI SCL Model has improved the SIF program by bringing a consistent and objective approach to reviewing, classifying, and deploying corrective actions to prevent reccurence of SIF incidents across the Company and industry.

Once an incident is determined to meet SIF criteria, a cause evaluation team is assembled to investigate the facts of the incident, and identify the causal and contributing factors. The team also develops comprehensive corrective actions to minimize and/or prevent reoccurence. Upon completion of the internal investigation, a written report is presented to the Corrective Action Review Board (CARB) to evaluate and accept the corrective actions. The CARB is composed of Gas Leaders, Gas Corrective Action Program (CAP) Leaders, Enterprise Health and Safety (EH&S) Leaders, and is cross-functionally supported from other areas of the enterprise. This enterprise CARB showcases maturity and allows the ability to better challenge and drive learnings across the functional areas. Once approved, the corrective actions are entered into CAP and tracked and monitored to completion. Following closure of all corrective actions, an effectiveness review is conducted to determine if the actions taken were effective in preventing or mitigating the original outcome. PG&E continued additional evaluation measures in 2025, such as Timely Corrective Action Completion and Quality of Corrective Actions, to focus on both the quality and timely closure of corrective actions from SIF investigations. Last year, Gas completed 100 percent of the corrective actions related to SIF events on time.

One layer of control in preventing workplace injuries is Personal Protective Equipment (PPE). Employees are required to wear appropriate PPE when they are in the field and can refer to PG&E's PPE Matrix, which documents the minimum PPE required when performing certain tasks. PG&E annually

reviews its PPE Matrix to evaluate the appropriateness of current PPE requirements. Employees in the field also document the controls for any identified hazards associated with their tasks using a JSSA form. PG&E's PPE Matrix and JSSA are vital resources for employees as they plan their work prior to completing it in the field.

Another area of focus continues to be Motor Vehicle Safety. In 2025, Gas T&D saw a twelve percent decrease in the number of Preventable Motor Vehicle Incidents on Public Roads (PMVIP), going from 68 in 2024 to 60 in 2025. There were eleven Serious Preventable Motor Vehicle Incidents (SPMVI), which was an increase of two SPMVIs from 2024.

PG&E tracks a Safe Driving Rate (SDR) metric by calculating the number of Hard Braking events and Hard Accelerating events per 1,000 miles driven, and uses in-cab coaching technology in gas vehicles to alert drivers when they accelerate too fast or brake too hard. These are both leading indicators for incidents that have the potential to cause extensive damage or a SPMVI. Vehicles with an SDR greater than 30 are 1.5 times more likely to be involved in a Preventable MVI. In 2025, Gas finished with a SDR of 3.4, a decrease from the 3.5 recorded SDR in 2024. The Company continues to improve its motor vehicle safety program, conduct more driver observations, install backing sensor technology, enhance driver safety training, and promote awareness campaigns such as Driver Rodeos focused on drivers and their specific vehicles. PG&E will continue to strive to reduce OSHA recordable injuries, the DART rate, and motor vehicle incidents.

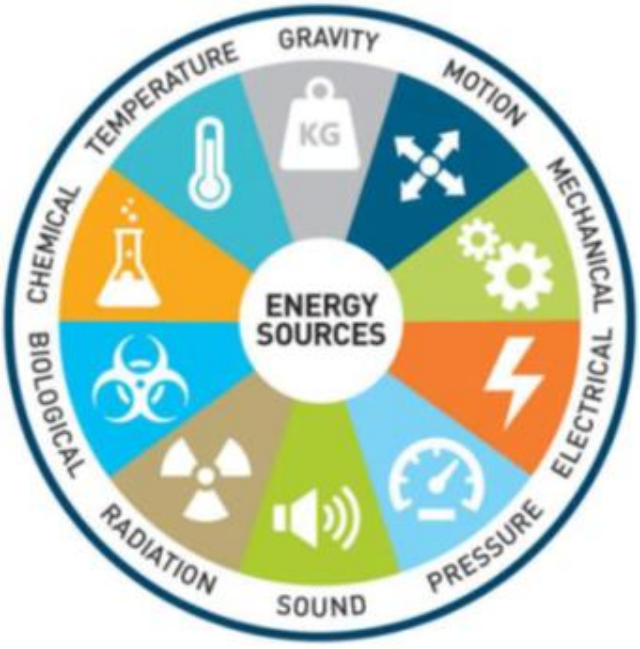


Figure 5 – Hazardous Energy Wheel

6. REWARDING SAFETY EXCELLENCE

PG&E's performance goals reinforce expectations regarding management decisions and allocation of resources. PG&E awards employees and contractors for their safety excellence by encouraging safe behavior and practices. These awards include:

Eagle Eye Award – Recipients of this award are those who submit CAP items identifying and addressing issues that result in significant improvements to safety, reliability, compliance, cost reduction, or process. Any employee can submit an Eagle Eye nomination.

Speak Up Awards – This program honors those who bravely speak up about an issue or concern, ranging from a safety issue to new ideas. In 2025, there were two Speak Up Champions. Both issues that were raised by the champions had safety implications.

Safety Recognition Program – Under this program, rewards and recognition are provided for employees who demonstrate safe behavior, speak up, and take action to promote a positive safety culture, and/or support the Workforce Safety Strategy. As a token of appreciation, the employees who nominate them are also eligible to receive rewards and recognition.

Process Safety Champion – This quarterly champion recognition distinguishes teams and individuals who have gone above and beyond in applying process safety principles to their work. Examples are having a questioning attitude, taking time to evaluate hazards prior to starting tasks, and submitting material issues into the CAP system. Champions are identified and recognized in the Process Safety Newsletter.

Regional Safety Recognition – The Regional Safety Recognition is a cross-functional program that recognizes safe behaviors and/or demonstrations of safe acts outside of the workplace. In 2025, 150 Gas T&D coworkers were nominated for their focus on safety and helping fellow coworkers.

Sibley Award – The Sibley award recognizes organizations that make outstanding contributions toward the safety and health of the public, employees, contractors, and customers. In 2025, it was awarded to a Gas Program Manager for creating Grassroots TV, which positively impacted PG&E's safety culture. The more than 450 videos the award-recipient has produced since 2013 use peer-originated stories and demonstrations to address safety issues, bring real situations to life and enhance safety focus.

811 Ambassador Program – This program encourages employees to report unsafe excavations activity to help prevent utility dig-ins and protect public safety. Through a tiered point system, employees who identify and report potential hazards are recognized with quarterly rewards, including gift cards and charitable donation opportunities [see *Section IV.4.a Damage Prevention for more information*].

Britton Award – This award recognizes individual coworkers, or teams, whose actions display an exceptional lifesaving, courageous, or self-sacrificing behavior or deed that demonstrated initiative and resourcefulness in an emergency. In 2025, twenty-three Gas T&D coworkers were awarded the Britton for taking actions above and beyond the call of duty.

II. SAFETY CULTURE

PG&E's commitment to strengthen our safety culture and performance is reinforced by the stand that "Everyone and Everything is Always Safe" (see Figure 6). Gas Safety and Leadership work together to improve workforce safety through building a culture focused on employees. They also cultivate a deeper partnership between Gas Leadership, Grassroots Safety Teams, and the Labor Unions. The goals of the partnership are to prevent and reduce employee serious injuries and fatalities, to promote healing and return to work, and to provide quality and appropriate medical care for our coworkers. In 2025, with leadership support, Gas focused on these goals as well as strengthened its safety culture through collaboration with external safety-culture professionals, whose specialized insight helped elevate expectations, sharpen practices, and reinforce a strong foundation for internal leaders.

Progress in strengthening safety culture was reflected in the results of the National Safety Council (NSC) Safety Culture Barometer Survey conducted in early 2025. Gas T&D achieved an overall 83rd percentile ranking compared to more than 1,400 organizations. Participation in the survey was strong, with 3,777 Gas T&D coworkers (72 percent) completing the survey and 1,397 coworkers (37 percent) providing written feedback. Collectively, the results point to meaningful gains in leadership involvement, employee participation, and organizational climate. These results reinforce that safety culture improvements are being experienced across the workforce. To continue advancement, Gas T&D convened a cross-functional working team of coworkers and Enterprise Health & Safety partners to review survey insights alongside other leading indicators. The focus of this team is on identifying targeted actions that build on existing strengths and address opportunities for further development. This work reinforces PG&E's commitment to learning and continuous improvement.

In 2025, Gas continued to participate in the Operations Safety Collaboration Center (OSCC) to drive leadership alignment and action in preventing SIF events and Near Hits. In December 2024, the OSCC advanced strategic planning, which included selecting the 2025 Areas for Improvement (AFI). The AFI's were Human Performance (HU) Pre-Job Safety Briefing, High Energy Gravity Line of Fire, and Organizational Culture and Safety Mindset. In Q3 of 2025, the OSCC added a new emergent AFI focusing on Falls While Working at Heights. As part of the Organizational Culture and Safety Mindset AFI, Gas hosted several safety culture-based workshops and grew from nine Safety Culture Village Guidance teams to eleven teams. Throughout 2025, there was tremendous progress in each of the AFIs resulting in exceptional cross-functional collaboration and effort in areas that are expected to significantly support SIF prevention efforts in Gas.

This past year marked noteworthy progress in expanding and maturing HU initiatives. Key achievements included the reinstitution of the HU Oversight Committee to strengthen governance and accountability, the creation of a dedicated Gas HU SharePoint to centralize resources, and the

development of a comprehensive HU starter kit for new team members. To enhance awareness and understanding of HU tools, there was a launch of targeted marketing and engaging videos highlighting the benefits of using the tools. HU training was delivered across Gas T&D and there were expanded training opportunities for Gas Engineering, Gas Pipeline Operations and Maintenance (GPOM), and Gas T&D teams. These teams also hosted 57 HU Workshops, which included 1,018 Gas coworkers. This promoted a consistent culture of excellence and safety throughout the organization.

The Safety Culture Village Guidance Team continued to be an integral part of the culture improvement efforts at PG&E. As mentioned earlier, the larger team is comprised of eleven teams, including bargaining unit and management coworkers. These coworkers are carefully selected for being safety leaders who positively influence their teams at the local level. The Safety Culture Village Guidance Teams choose the aspects of their local safety culture they believe, if enhanced, will promote work safety. The third annual Gas Safety Culture Summit was held in late 2025. The summit served as a platform for all eleven safety culture villages to exchange best practices, provide extensive training on safety culture tools, and gain insight from each team regarding the projects and actions that were effectively executed and influenced cultural change in 2025.

In addition, many more Gas coworkers continued to receive training to become certified Safety Culture Tools Facilitators who assist coworkers supporting Gas-wide culture topics. In 2025, the training provided was for two specific culture-based tools: Culture Iceberg and Cycle of Mistrust. The utilization of these powerful tools is used to problem-solve and improve the safety culture of our workforce, as well as to equip teams with advanced cultural insights. There were also four comprehensive three-day Safety Culture Workshops for Gas that reinforced commitment to a strong, proactive safety culture. To further promote collaboration and knowledge sharing, PG&E hosted two Safety Culture Roundtable events, providing a platform for open dialogue and best practice exchange, reinforcing our commitment to a robust, sustainable safety culture.

Figure 6 – PG&E Stands

In parallel, PG&E continued with its Gas Safety Council and Gas Grassroots Safety teams in 2025. PG&E advanced Grassroots engagement efforts by successfully conducting an election series for Grassroots Chairs within each functional area, showing strong representation and leadership at the local level. PG&E also launched the 2026 Grassroots-Led Safety Council HU Campaign, empowering teams to drive Human Performance initiatives from the ground up and reinforcing a culture of safety and accountability across the organization. More information on the Gas Safety Council can be found in *Section II.2.a*. More information on the Grassroots Safety Teams can be found in *Section II.2.b*.

As an organization, PG&E's ongoing focus is to reduce unsafe behaviors by connecting with those who do the work, building and improving the Safety Culture of our employees, and continuing to build a deeper partnership between Gas and Labor Unions.

1. COWORKER ENGAGEMENT

PG&E continues to develop and execute coworker and leadership engagement activities and initiatives that support a healthy safety culture, align with our TNS and Gas Stand, and support frontline coworkers. These efforts are designed to empower those closest to the work to make informed decisions and stop work when needed. PG&E's coworker engagement strategy incorporates the three elements of the Performance Playbook (Lean Operating System, PSEMS, and Breakthrough Thinking). In addition, Gas maintains a targeted communication and engagement strategy to relay information about safety stand-downs and all coworker calls when serious events or changes occur. This strategy utilizes tools from the Performance Playbook to be effective and timely. Additionally, the primary initiatives that make up the Gas coworker engagement strategy include developing plans based on Joy at Work results, Inclusion and Belonging Activities, volunteer and community events, and leadership development and support programs, such as Role of the Supervisor.

Performance Playbook

Lean Operating System. Lean implementation has a large influence on coworker engagement. The Lean Operating System (LOS) was first introduced to Gas in 2017 and has continued to mature each year. It utilizes five plays to drive more effective and responsive decision-making, reduce challenges faced in day-to-day work, and deliver better outcomes for our customers. These plays are Visual Management, Operating Reviews, Problem Solving, Standard Work, and Waste Elimination. The LOS encourages leaders to spend more time directly engaging with their team members, with daily, weekly, and monthly operating reviews, command centers, and in-field visits. Through the LOS, the engagement with leaders is maximized with effective views of metrics, tools to solve problems, and a process to eliminate waste and unproductivity.

LOS improves safety performance in many ways. With Visual Management, being able to see safety performance allows coworkers to immediately identify potential areas of improvement using real time data. Operating Reviews allow for brief, focused discussions to identify and address issues and barriers to getting the right work done, allowing those closest to the work to collaborate in decision-making and escalate safety incidents in real time. Problem Solving resolves issues and negative trends that impede performance as soon as they are flagged, and Standard Work supports effective safety processes and best practices that are in place for continuous improvement. Waste Elimination means elimination of non-value-added work, allowing more focus on safe completion of goals.

PSEMS. The PSEMS is a systematic management of processes, assets, and occupational health and safety to prevent injury and illness. The PSEMS framework includes the 13 elements, which allow the organization to operate safely and deliver safe, reliable, affordable, and clean energy to our customers and hometowns. More details on the PSEMS can be found in *Section I.3*.

Breakthrough Thinking. Breakthrough Thinking is PG&E's structured approach for helping leaders and teams intentionally move beyond "business as usual." A breakthrough organization is one in which leaders and teams consistently recognize where changes in mindset, decision making, or execution are needed to reduce risk and strengthen safe performance. In Gas, Breakthrough Thinking encourages leaders and coworkers closest to pause, challenge past-based thinking and assumptions, and take deliberate actions to discover new possibilities that will cause safety outcomes in alignment with the safety stand, "Everyone and everything is always safe." This approach is reinforced through four main Breakthrough building blocks—Breakthrough Intensives, Performance Diagnostics, Breakthrough Specialists, and Breakthrough Debriefs, that provide tools and methodologies for leaders to cause breakthrough outcomes in safety, performance, and customer experiences. In 2025, PG&E hosted six Breakthrough Intensive courses for 701 coworkers, launched a redesigned Supervisor Breakthrough course that ran 23 times with 424 supervisors participating, and onboarded 47 new Specialists to continue strengthening this capability across Gas.

Joy at work

Joy at Work Survey. PG&E is committed to fostering an enjoyable work environment for all employees and is dedicated to prioritizing safety, both physical and psychological, as fundamental aspects of our organizational culture. To gain deeper insights into the experiences of our coworkers, PG&E has maintained its annual joy at work survey aimed at assessing employee satisfaction and their feelings of being valued, appreciated, and proud to be part of the organization. In 2025, a total of 3,966 employees from Gas T&D and 787 from Gas Engineering participated in the survey, achieving joy scores of 73 percent, consistent with the previous year's findings. The survey results offered valuable insights for leaders and their teams, highlighting actionable strategies to enhance workplace joy, such as team-building activities, volunteer opportunities, and in-person collaborations, among other initiatives. The 2025 survey underscored the necessity of implementing solutions that foster the safety of coworkers in the field, strengthen support for both physical and mental well-being, and actively address concerns that may hinder performance. As we look ahead to 2026, PG&E will continue its focus through the Joy at Work Survey to poll employees on many levels, including safety.

Dedication to prioritizing safety, both physical and psychological, as fundamental aspects of our organizational culture.

Top Initiatives. In 2025, Gas advanced several initiatives designed to strengthen safe performance, emergency readiness, and workforce capability, including the Gas Mentorship Program, the PG&E IBEW (International Brotherhood of Electrical Workers) Gas Rodeo and National Gas Rodeo, Live Action Drills, and a range of volunteer events, such as Activate the Planet. Through the Gas Mentorship Program, experienced coworkers are paired with less experienced coworkers based on desired skills and knowledge sharing, transfer practical field experience, reinforce safe work practices, and support professional development. The PG&E IBEW Gas Rodeo promotes technical skills, teamwork, and adherence to safety fundamentals critical to the natural gas delivery industry; in 2025, the top PG&E team advanced to the National Gas Rodeo and earned first place. PG&E also hosted 12 Live Action Drills in partnership with local authorities, including fire departments, to test and practice emergency response strategies and coordination, strengthening preparedness for gas-related incidents. Activate the Planet provides coworkers opportunities to support community safety and resilience; in 2025, participants helped prepare the Yolo Basin ahead of flood season. Collectively, these initiatives reinforce connection, accountability, and shared responsibility for coworker, public, and community safety.

Other Notable Initiatives. In addition to Gas-specific initiatives, PG&E also participates in well-established programs that reinforce safety awareness, recognize safe behaviors, and strengthen a culture of accountability that supports gas safety performance. These include National Gas Utility Worker Day, Speak Up and Champion Awards (see Section I.6, *Rewarding Safety Excellence*), National Safe Digging Month, and the 811 Ambassador Program (see Section IV.4.a, *Damage Prevention*), all of which promote hazard awareness, damage prevention, and proactive identification of safety concerns. PG&E also conducts a winter gas safety campaign to educate customers about a free appliance inspection program. This program helps customers with the safe operation of their gas appliances and promotes awareness of the free pilot relight program. In addition, PG&E recognizes service anniversaries and Progress Maker achievements, where coworkers are acknowledged for actions or process improvements that align with PG&E's safety stands and contribute to safer work execution. Collectively, these initiatives reinforce consistent safety messaging, encourage speaking up, and integrate safety recognition into everyday workflows, supporting both public and workforce gas safety.

Reinforce consistent safety messaging, encourage speaking up, and integrate safety recognition into everyday workflows

Inclusion and Belonging. All coworkers should feel a sense of belonging, which is a critical component of psychological safety. To help foster belonging, Inclusion and Belonging (I&B) at PG&E is a big part of joy at work. Included in it are the Joy Council, which included the Gas Senior Vice President as the I&B champion for Gas T&D. In 2025, Gas sponsored a Belonging Day, where all Employee Resource Groups (ERG) were represented, and a panel was held. The Joy Council also holds quarterly meetings

where each functional area provides updates on what they do to provide support for I&B, and to implement joy plans. Joy plans may include mentorship, site visits, or any joy events held in functional areas (for example, chili cookoffs, family days in yards, and all-hands meetings).

Leadership Development Programs

Safety Leadership Development. In 2025, the *Leading Forward: Safety Leadership* program continued to be delivered to operational leaders, including gas supervisors and crew leads, covering topics of Shaping a Safety Culture, Identifying and Controlling Exposure, and You Are Not Alone. The program also includes information about the PSEMS and the Institute of Nuclear Power Operations 10-Traits of a Healthy Safety Culture. In 2025, the Grassroots Safety Committee continued for hybrid and office-based coworkers to better support ergonomics and the changing landscape where work is completed.

Leader in the Field. Leader in the Field was deployed in 2020, with a focus on supervisors and managers physically being in the field with their coworkers to assist in removing barriers and resolving safety concerns. During in-field visits, leaders regularly visit locations where the work is occurring to meet coworkers, to hear what is working well and where improvements are needed, and to observe the work being performed to identify opportunities for continuous improvement. Across Gas, supervisors' time in the field averaged approximately 63 percent throughout 2025, an increase compared to 62 percent in 2024 and 56 percent in 2023. This means over half of their working hours were spent in the field with frontline workers. For PG&E Gas Operation Managers, time in the field averaged approximately 38 percent throughout 2025, an increase from 37 percent in 2024 and 31 percent in 2023.

Role of the Supervisor. The Role of the Supervisor program elevates and strengthens supervision as a critical control in gas safety by allowing supervisors to be equipped, supported, and engaged in leading safe work execution, reinforcing safety culture, and addressing risks before incidents occur. By redesigning the supervisory role to be an attractive, supported, and aspirational position across the Company, PG&E enables supervisors to consistently set expectations, remove barriers to safe work, and model safety-focused decision-making in the field. In 2025, PG&E continued to enhance supervisor engagement through additional Supervisor Central Program First Line Network calls and Office Hours; shared Day in the Life and Time-in-Motion study results with supervisors in collaboration with the Enterprise Lean Office and Lean Yard teams to improve workload balance and field presence; and engaged functional area leads to address operational and safety challenges. PG&E also continued its 2025 *Leading at PG&E* leadership training offerings, delivering six courses focused on leading coworkers, strengthening safety culture, business acumen, breakthrough thinking, and lean principles, all of which support safer gas operations. The Role of the Supervisor was measured through the 2025 Joy at Work

survey, with 85 percent supervisor participation and overall Supervisor Joy remaining steady at 77 percent, reflecting sustained engagement in this key safety leadership role.

Leadership Town Halls. Previously named Coworker Town Halls, 11 Leadership Town Halls (LTH) were hosted in 2025. These town halls were designed for leaders to focus on being owners, together. They built trust by discussing our Performance Playbook, maturing our Safety Culture mindset, and getting deeper into our LOS. Spanning our territory, these town halls provided a mechanism for leaders to collaborate, discuss relevant issues and ideas, and learn from each other to improve effectiveness, efficiency, competency, and safe operations. A big focus at each LTH is on safe operations and execution, with segments ranging from PSEMS to controls to lean tools, creating another forum for leaders to learn from each other, talk about best practices and ideas, then bring those insights back to their teams.

2. CORRECTIVE ACTION PROGRAM (CAP)

The Corrective Action Program supports Gas safety culture by providing a structured process to identify, evaluate, and address and correct safety issues. PG&E's continued use and support of CAP demonstrates to coworkers, contractors, regulators, and customers its unwavering commitment to deliver safe, reliable, affordable, and clean energy.

The Gas CAP team is composed of CAP quality operations specialists and cause evaluators. The quality operations specialists handle day-to-day management of CAP submissions while the cause evaluators facilitate the end-to-end process of an investigation or cause evaluation (root, apparent, or common cause). The cause evaluation team is also responsible for all SIF coworker investigations and works in conjunction with Enterprise Safety to strengthen effective implementation of the process.

What Gets Reported into CAP

PG&E encourages employees to identify issues related to gas assets, processes, compliance, and the overall safety of our employees, contractors, and the public for submission into CAP for resolution and tracking.

How the Gas CAP Process Works

Initiation: The initiator, who can be any PG&E employee or contractor, can submit any issue or process improvement idea into the CAP system. Coworkers have several ways to submit an issue, and can choose to do so electronically, manually, or verbally. Once the CAP is in "submitted" status in Gas, the Gas CAP team will process it for assignment. Over a six-year period, Gas employees have submitted an average of 745 CAP issues per month.

Assignment and Resolution: The CAP process employs a standardized approach (Figure 7) to review and assign CAP Issues and Actions. This process is facilitated by the Gas CAP Review Team (CRT), composed of Subject Matter Experts (SME) from various Gas departments who meet twice weekly to

review newly submitted CAP notifications. The CRT categorizes each notification, assesses it for severity (using the enterprise CAP Severity Determination Table – see Figure 8), and assigns it to an issue owner.

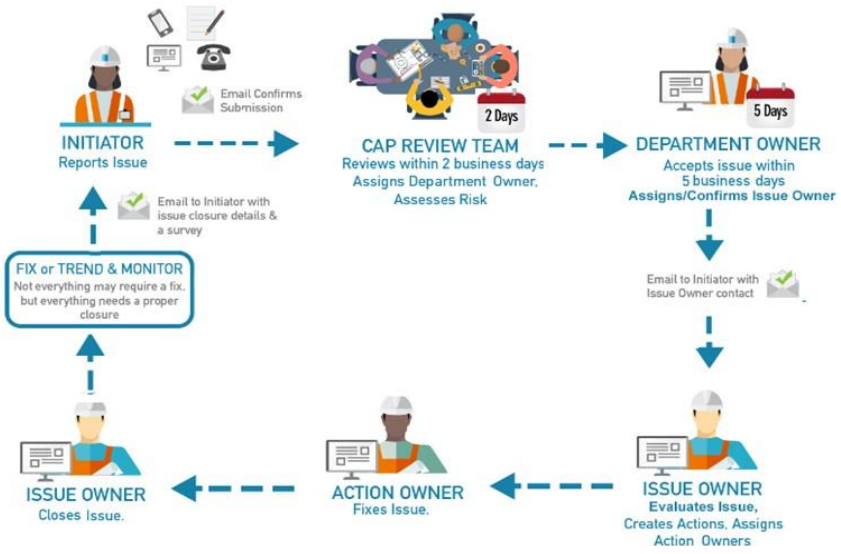
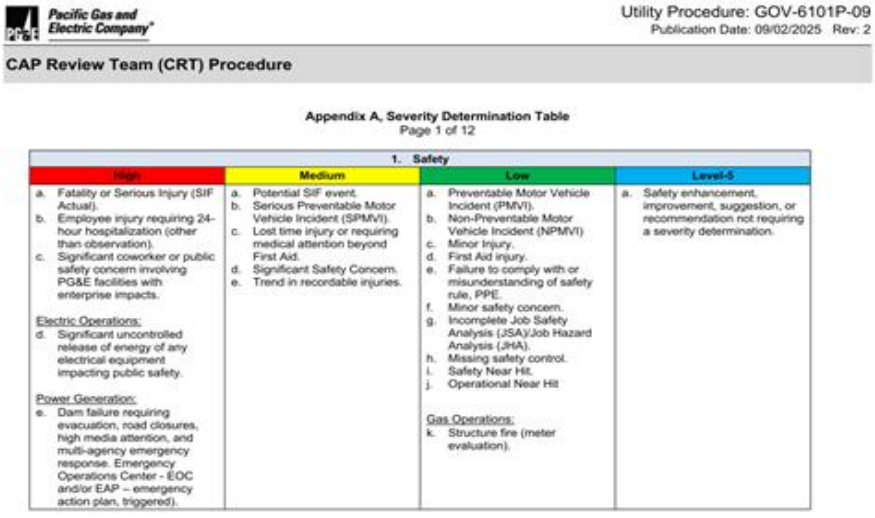


Figure 7 – CAP Process

Once the CAP is assigned to an issue owner, it is the issue owner's responsibility to review the notification, identify the causes underlying the issue, and address them appropriately by implementing any necessary corrective actions to mitigate risks and/or prevent recurrence (based on severity and evaluation level). After a CAP notification has been submitted to an issue owner, initiators receive an email detailing to whom their notification was assigned. They also receive another email when their notification is closed. This gives the initiator the opportunity to learn how the issue was resolved and to provide feedback on the results.



Pacific Gas and Electric Company®

Utility Procedure: GOV-6101P-09
Publication Date: 09/02/2025 Rev: 2

CAP Review Team (CRT) Procedure

Appendix A, Severity Determination Table
Page 1 of 12

1. Safety			
High	**Medium**	**Low**	**Level-5**
a. Fatality or Serious Injury (SIF Actual). b. Employee injury requiring 24-hour hospitalization (other than observation). c. Significant coworker or public safety concern involving PG&E facilities with enterprise impacts. Electric Operations: d. Significant uncontrolled release of energy of any electrical equipment impacting public safety. Power Generation: e. Dam failure requiring evacuation, road closures, high media attention, and multi-agency emergency response. Emergency Operations Center - EOC and/or EAP – emergency action plan, triggered).	a. Potential SIF event. b. Serious Preventable Motor Vehicle Incident (SPMVI). c. Lost time injury or requiring medical attention beyond First Aid. d. Significant Safety Concern. e. Trend in recordable injuries.	a. Preventable Motor Vehicle Incident (PMVI). b. Non-Preventable Motor Vehicle Incident (NPMVI) c. Minor Injury. d. First Aid injury. e. Failure to comply with or misunderstanding of safety rule, PPE. f. Minor safety concern. g. Incomplete Job Safety Analysis (JSA)/Job Hazard Analysis (JHA). h. Missing safety control. i. Safety Near Hit. j. Operational Near Hit Gas Operations: k. Structure fire (meter evaluation).	a. Safety enhancement, improvement, suggestion, or recommendation not requiring a severity determination.

Figure 8 – CAP Severity Determination Table

How CAPS are Prioritized

CAP assigns a Severity Level to all incoming CAP issues using the CAP Severity Determination Table delineated in GOV-6101P-09. The CAP notification severity level along with guidance provided in GOV-6101P-09 Appendix B is used to determine the appropriate evaluation type that will be assigned, if needed. There are four types of cause evaluations:

- **Root Cause Evaluation (RCE):** An RCE is a formal and rigorous investigation that uses analysis methods to determine the root cause(s) of a problem. The RCE identifies required corrective actions that prevent or reduce the likelihood of a recurrence of the problem for the same or similar root cause(s).
- **Apparent Cause Evaluation (ACE):** An ACE is an evaluation based on readily available information that provides reasonable assurance that the cause of a problem is determined and will be corrected. An ACE is conducted when management determines a formal but less rigorous cause evaluation is necessary.
- **Common Cause Evaluation (CCE):** A CCE is an analysis method that can be used to identify common underlying elements among different, unique, but similar events or issues. The underlying elements may be anything from a common failure mechanism to a common cause that may or may not require further investigations. A CCE can be conducted only when the individual issues have been evaluated on their own merits (i.e., ACE or WGE report completed) and causes and corrective actions have been identified.
- **Work Group Evaluation (WGE):** A WGE is a logical evaluation of an issue to identify reasonable corrective or preventive actions needed to resolve the issue. Resolution of the issue may be addressed by another process or a simple explanation of why something does or does not happen.

A cause evaluation can be related to a wide range of topics in Gas, such as asset failures, reliability (e.g., dig-ins, overpressure (OP) events), and workforce safety incidents (i.e., SIF incidents). A cause evaluation can be requested by an employee on any CAP notification; however, an RCE is generally assigned to incidents where the consequence severely impacts public or employee safety, or reliability, and warrants rigorous analysis. Table 2 shows the total number of evaluations completed in 2025.

Table 2 – Gas Cause Evaluations Completed in 2025			
RCE	ACE	WGE	CCE
2	11	8,309	0

How CAP Success is Measured

In 2025, Gas' goal was to engage at least 33 percent of its workforce to use CAP to encourage employees' participation, and at year-end it engaged approximately 24 percent. Typically, Gas is assigned between 8,500 and 9,500 CAPs per year. To maintain accountability and transparency, leaders have access to an Executive CAP Dashboard tool (Figure 9) and the ability to subscribe to reports each week that detail how their organization is performing on their CAP items. Additionally, officers and directors receive a daily report containing CAP issues submitted the previous day prior to being vetted through CRT. This daily report provides advance awareness of issues that may require proactive actions, interim controls, or containment.

Key performance indicators (KPI's) reported in 2025 include:

- **Percent of Unique Initiators** – This is the number of employee submissions divided by the total count of employees. The 2025 goal was greater than or equal to 33 percent of unique initiators.
- **CAP Throughput** – This number measures the volume of work being completed by the organization. The 2025 goal was 1.0, meaning that the volume of closed notifications equals the volume of submitted notifications.
- **Average closure satisfaction (1-5 scale)** – This is the sum of survey scores divided by the number of survey submissions. The 2025 goal was an average closure satisfaction greater than or equal to 3.5, where 5 is "very satisfied" and 1 is "did not meet expectations."
- **Quality closure (percent)** – This is the number of CAP notifications passing quality review divided by the number of CAP notifications reviewed. The 2025 goal for quality closure was greater than or equal to 92 percent.
- **Average Age of Open High-Risk Notifications (days)** – This is the number of days high-risk notifications are open divided by the number of open high-risk notifications. The 2025 goal for average age of open high-risk notifications was 180 days.
- **Average Age of Open Medium-Risk Notifications (days)** – This is the number of days medium-risk notifications are open divided by the number of open medium-risk notifications. The 2025 goal for average age of open medium-risk notifications was less than or equal to 210 days.

Figure 9 shows how Gas performed against the above-mentioned KPI's in 2025.

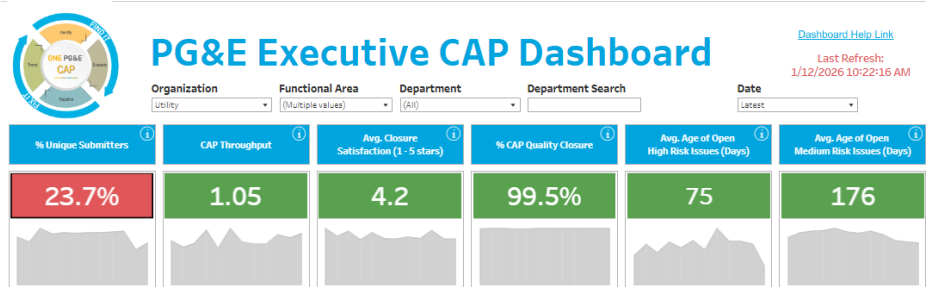


Figure 9 – CAP Metrics

Continuous Improvement and Speak Up Culture

The Gas CAP process continues to mature and serve an important role in Gas to identify and mitigate operational and safety issues as well as implement process improvements. The Gas CAP department looks for ways to improve how it supports the business and continues to bring added value to operations. Some examples are highlighted below:

Eagle Eye Program: In 2025, the Gas CAP Department logged 34 Eagle Eye nominations [see *Section I.6 Rewarding Safety Excellence*], which included nominations for identifying and submitting "good catch" issues and for efforts in resolving those issues.

Near Miss Reporting: Gas encourages the use of CAP for Near Miss reporting, asset dig-ins, process improvement recommendations, and general safety concerns. In addition, Gas CAP serves as a work management system for activities such as mapping updates, MVI and injury tracking, and compliance tracking, which contributes to overall submission volume. As a system of record and enterprise work management tool, CAP supports the identification and resolution of issues across a broad range of topics and reflects Gas's ongoing commitment to fostering a strong speak up culture.

Trending: In 2025, the Gas CAP team implemented the trending process from the model used by Diablo Canyon Power Plant (DCPP). Using the model, the CAP team reviews all safety-related CAP issues and assigns a behavior/mindset attribute. This is then incorporated into a dashboard for visual insights and to determine trends through data analysis. In 2025, the team identified two negative trends. One negative trend was for Electrical Hazards to Gas Employees while performing excavation. It is being addressed in the Quality Improvement Plan for Excavation. The second negative trend was procedural use and adherence in Locate and Mark, which is related to dig-ins. The trend was validated by that team as a previously known issue and is continuously addressed through their standard processes.

Quality Closure Review (QCR): QCR is a process in which the CAP team reviews closed notifications to determine if the responses meet the minimum quality closure requirements. Gas CAP reviews 100 percent of all High and Medium severity closed notifications and at least 50 percent, or more, of closed Low severity notifications on a weekly basis. This process adds value to the organization by creating an expectation on how a notification should be resolved and closed.

a) Industrial Athlete Program

The Industrial Athlete Program provides education and early symptom intervention to help our field coworkers avoid injuries and stay safe, healthy, and well at work. Industrial Athlete Specialists (IASs) are professionals trained in sports medicine. Twenty-one IASs are assigned to regions throughout the enterprise service territory and each IAS regularly visits sites within their region. They are also available for "on call" services.

IAS Services include:

- Body mechanics coaching to prevent injuries on the job;
- Individual and group education on topics such as performing;
- Task-specific stretches and preventing sprains and strains; and
- Support for discomfort, both work-related and non-work related.

In 2025, 30 percent of the Gas eligible physical workforce participated in 1:1 services with an IAS with 3,591 preventative 1:1 visits and 1,065 discomfort-related visits. Additionally, there were 5,069 group events in Gas T&D involving an IAS with a total of 59,576 event participants. Approximately 94 percent of coworkers with a resolved IAS discomfort case did not have a new MSD-related worker's compensation claim within six months after case closure.

b) Office and Industrial Ergonomics

In 2025, the Office Ergonomics team completed 4,154 workstation evaluations across the Enterprise. The ergonomics risk management software, RSIGuard, was retired in late 2024 and new software applications were introduced in 2025 (Ergo4Me, Wellnomics, Appointedd, and Longitude6 wearables). The new Ergo4Me platform consolidates ergonomics training, self-assessment, and corrective action plans for all office and frontline PG&E coworkers and allows PG&E to assess ergonomics risk from a holistic standpoint, and to align program resources needed to mitigate risk.

In 2025, ergonomics goals for all coworkers will focus on implementing corrective actions resulting from the completion of annual ergonomics training and self-assessment. This should proactively reduce ergonomics risk with a Company-wide goal of implementing all corrective actions within 60 days post-training completion. In 2025, 54 percent of all PG&E coworkers resolved their ergonomics risk by implementing their corrective actions plan. Employees with work-related discomfort are advised to contact the NCL for discomfort resolution. In accordance with PG&E's Ergonomics Standard, corrective actions are to be addressed within 60 days after completing ergonomics training and self-assessment.

Last year, PG&E continued to initiate and execute industrial ergonomics projects designed to improve employee safety. Industrial ergonomic projects in 2025 included the GC Gas Driving Grounding Rods project. In this project, the Industrial Ergonomics team, Gas T&D and the Grassroots Safety Team conducted a risk analysis of the available tools used for driving grounding rods. The team noted that while there are different tools available for the task, the current standard for grounding underground equipment does not provide guidance on specific tool use for the task given work conditions. Four different tools were assessed with potential to reduce ergonomics risk by approximately 92 percent using the gas-powered post driver compared to using the pneumatic manual driver. Two new tools were also identified that will be included in the comparative analysis results in 2026, once the tools are available

for piloting and assessment. In 2026, the team will partner to update written guidance in a standard regarding tool selection and criteria for inspecting and maintaining tools.

c) Ethics & Compliance Helpline

PG&E's Ethics and Compliance (E&C) Helpline is a toll-free telephone number and website available to employees, contractors, consultants, suppliers, and customers 24 hours a day, 7 days a week. The E&C Helpline, managed for PG&E by EQS, enables reporting parties to request guidance about our Code of Conduct (Code) or make a good-faith report of violations such as fraud, accounting issues, or illegal activity. Callers may remain anonymous throughout the entirety of their interaction with the helpline as well as any subsequent contact with E&C.

Concerns raised with E&C through its Helpline, or any other method, are documented and tracked to closure. The Workplace Ethics Committee for Action, Responsibility and Engagement (WECARE) reviews cases that are substantiated for misconduct or unsubstantiated but have recommendations for process improvements to maintain consistency in disciplinary action across the enterprise and continuous improvement. The committee is made up of coworkers from Ethics and Compliance and People and Operations. PG&E has a strict policy against retaliation against anyone who speaks up or is involved in an investigation. The E&C Helpline is part of PG&E's commitment to foster a workplace where everyone feels safe to ask for guidance, share ideas, or raise concerns. It is also a culture where everyone is confident that those concerns will be heard, taken seriously, and thereafter followed up in a timely manner.

d) Material Problem Reporting

PG&E encourages employees to report and act on problems with any materials, tools, gas, electric, and other equipment or infrastructure through the Material Problem Reporting (MPR) system. PG&E leverages the CAP reporting process [see *Section II.1.a Corrective Action Program* for more information] to route material related problems to the MPR system. The MPR process is cross-functional and relies on employees at all levels of the business to identify potential safety issues stemming from material problems.

MPRs can be identified from two different sources:

1) As material arrives at PG&E's facilities, the PG&E team may identify "Incoming MPRs."
2) As work is performed with materials, personnel may identify "Field MPRs."

Incoming MPRs that are quality tested and found to fail at receipt prompt the creation of a Supplier Corrective Action Request (SCAR), requiring the supplier to resolve the issue. The SCAR process and system is managed by Supplier Quality Assurance (SQA) to reinforce that proper corrective actions are

implemented. In 2025, the incoming gas MPR's had an average cycle time of five days, exceeding the target of 20 days.

Field MPRs are submitted by field personnel from various job sites and PG&E locations who either received a problematic new material or identified a failed part on an asset, as applicable. These Field MPRs are evaluated by Gas Engineering. PG&E uses trending from combined MPR data lists to review with SMEs. This is in line with the Wildfire Order Instituting Investigation (OII) requirements to trend MPRs generated in the field and allows insight into recurring material issues. Starting in 2023, Gas Technology Team meetings incorporated field MPR trend reviews into their agendas, enabling the timely examination of potential trends and facilitating investigation and corrective actions as applicable. In 2025, the field MPR program resulted in Supplier Quality issuing 11 SCARs and one purge (a purge is a PG&E system wide material recall). In 2026, PG&E plans to utilize MPR data and trending with relevant SME technical teams and explore ways to improve the process.

3. PG&E Company and Gas Safety Committees

PG&E's safety governance structure drives a consistent safety culture and aligns with PG&E's safety strategy and results. Table 3 describes PG&E's Company and Gas safety committees and meetings. Gas utilizes the forums described in Table 3 to maintain alignment with the Chief Safety Officer (CSO) and the Chief Risk Officer (CRO) across the enterprise. In addition to these standing committees and meetings, PG&E also executes three Safety Weeks annually. These Safety Weeks are spread out through the year and focus on topics like Human Performance Tools, Motor Vehicle Safety, PSEMS, and Healthy Safety Culture.

Table 3 – Safety Committees and Meetings	
Board of Directors Safety and Nuclear Oversight (SNO) Committee	Provides oversight and review of (i) policies, practices, goals, issues, risks, and compliance relating to safety (including public, employee and contractor safety), and compliance issues related to PG&E's nuclear, generation, gas and electric transmission, and gas and electric distribution operations and facilities ("Operations and Facilities"), (ii) significant operational performance and other compliance issues related to such Operations and Facilities, and (iii) risk management policies and practices related to such Operations and Facilities.
Operations Safety Collaboration Center (OSCC)	Provides a forum in which PG&E leaders identify today's critical safety risks, drive cultural behavior improvements, and enable high-energy essential controls for workers to fail safely. Through the OSCC, the goal is to eliminate SIFs, achieve cross-functional alignment related to high-energy SIF hazards and mitigations, drive awareness and improvement actions to maintain a positive Safety Culture and share best practices and critical learning opportunities.
Safety Weekly and Monthly Operating Reviews (WOR and MOR)	Provides a forum to focus discussion on safety related metrics and topics including SIF events, learnings, and mitigations, and safety strategy execution with a focus on monthly and annual performance against goals. Participants include the Senior Leadership Team and functional area leaders.
Corporate Security WOR	Provides a forum to focus discussion on security and safety issues that coworkers are facing, including mitigation strategies and learnings from current activities. Outcomes can be updated to include program enhancements and expansion, including security liaisons and support to other parts of the service territory.
Weekly Cross-Functional Safety Incident Call	Provides a forum to discuss OSHA, DARTs and PMVIs, learnings and mitigations. Led by the Lead of Gas Distribution Operations, the participants include Gas Supervisors and Directors as well as Occupational Health, Transportation Safety and the Regional Safety Director.
Gas Safety Council	Sponsors initiatives to improve safety across Gas T&D. Monitors Gas safety performance and initiatives so that risks are adequately addressed. For more information on the Gas Safety Council, please refer to *Section II.2.a*.
Grassroots-led Safety Council	Establishes PG&E-level alignment across Grassroots Safety Teams. This Council facilitates sharing grassroots-based ideas across all functional areas to improve safety performance and share learnings and best practices so that everyone and everything is always safe. The Council includes representatives from all functional areas across the Company to focus on frontline and office workforce safety.
Gas Grassroots Safety Teams	Develops and implements employee-led, leadership supported efforts to identify opportunities to improve safety, define and validate possible solutions, and implement and promote safety initiatives. For more information on the Gas Grassroots Safety Teams, please refer to *Section II.2.b*.
Gas Training Alignment Committee	Provides a forum comprised of Academy, Gas T&D, IBEW, and safety partners, to provide strategic direction on training for Gas T&D as well as to continuously review and monitor Gas T&D training execution. This committee meets monthly to review progress on existing Gas T&D training initiatives and to identify and address emerging issues and training needs.
Safety Partners Meeting	Provides a monthly forum, hosted by PG&E and IBEW leaders, to openly discuss concerns, key initiatives, and opportunities for Enterprise Health & Safety to better support delivery of PG&E's Safety Stand – "Everyone and Everything is Always Safe".
Quarterly Injury Prevention Leader Engagement	Focused on preventing work-related injuries. Sessions are led by the Occupational Health Injury Management Program Manager and include a report on injury trends and recommendations for prevention. Guest speakers highlight different Occupational Health programs. Participants include functional area people leaders from across the enterprise.
Quality and Process Improvement Committee (QPIC)	Provides governance over process management framework including ownership, process design and improvements, controls, and overall process maturity, leveraging process framework to drive process performance as well as governance over the Gas Ops Quality Management System (QMS) including QA, QC, and new or revised quality programs.
Gas Contractor Safety Committee	Provides a forum, facilitated by the Gas Contractor Safety team, for collaboration with all gas contractor safety and operations leadership. This meeting is an open environment to discuss key health and safety initiatives, new or updated policies/standards/procedures, and Enterprise Contractor Safety team and Operator Qualifications team updates, concerns, and issues. The intent is to improve overall safety in the field with our contractor partners and their subcontractors. The committee meets three times per year. For more information on contractor safety, please refer to *Section V.4 Contractor Safety and Oversight*.
Contractor Safety Partnership Meeting	Provides a monthly forum comprised of safety champions and key leadership from all functional areas to discuss recent updates and modifications made to our Enterprise Contractor Safety Management Standard - SAFE-3001S, the associated procedures, and overall compliance with the Kern OII. The meetings are recorded, and notes are provided so that those unable to participate can still receive updates.

_____

(a) Kern OII is no longer an active investigation and is closed. The annual assessments of oversight procedures associated with Kern OII ensures PG&E continues to maintain compliance.

a) Gas Safety Council

In 2025, the Gas Safety Council was held monthly from February through December. This meeting is sponsored by the Senior Vice President (SVP) of Gas T&D and facilitated by the Senior Director of Gas Operational Excellence. The Council is composed of Senior Leadership, including the SVP of Gas T&D, Vice President of Gas Engineering, Vice President of Gas T&D, Senior Director of Gas Operational Excellence, and Labor Union Leaders from both the IBEW Local 1245 and the Engineering and Scientists of California (ESC). Invited attendees include the Grassroots Safety Teams,[7] Gas T&D, Gas Safety Excellence, Human Resources leaders, Gas Engineering, Enterprise Health & Safety, and others as needed. The primary objectives are to provide overall governance of safety, guide department safety strategy, maintain compliance with Company safety standards, execute Chairman's Risk and Safety Committee directives, provide another channel to raise safety concerns, and promote positive safety culture change.

Throughout 2025, the Gas Safety Council facilitated productive conversations and effective closure of 29 safety concerns and opportunities, including the review of High-Risk Standards, Heavy Equipment Operations Qualifications, the rollout of Tait Radio Training, electric faults impacting gas facilities, and fire resistant (FR) clothing requirements while performing 911 standby work.

b) Gas Grassroots Safety Teams

Gas Grassroots Safety Teams are composed of Chairs, Co-Chairs, and members primarily from Gas field positions. The Chairs meet on a regular cadence to discuss issues, strategy, concerns, successes, roadblocks, and any barriers that may exist. As of December 2025, Gas Grassroots had over 240 members. The teams include Field Services, Maintenance & Construction, Damage Prevention, General Construction , Corrosion, Leak Survey, and GPOM.

Highlights from Gas Grassroots in 2025 include:

- Organized and hosted Driving Rodeos, Regional Frontline Safety Culture Coaching and Partnership Workshops, and Safety Summits across all the PG&E Field Service territory.
- Hosted and facilitated 31 Hostile Environment Awareness Tactic (HEAT), or de-escalation, training sessions and 12 Live Action Drills throughout the PG&E Field Service territory, which included collaboration with multiple first responder agencies and other utilities.
- The "Safety and Performance Fundamentals Handbook" was created to promote individual thinking and action. It is meant to be both a guide to safe work practices and an aid to identify and correct unsafe conditions that may exist outside of our normal workplace – in the field, the office, and at home.

- Grassroots team members contributed to the creation and execution of workshops spanning the entire service territory, incorporating a fun hands-on learning activity to reinforce the 10 HU tools.
- Grassroots continued to help organize Third Thursdays to enhance safety culture through structured engagements. These monthly events provide a platform for colleagues to share incident information, complete training, share best practices and conduct equipment inspections. The development of the Third Thursday Toolkits and best practices are continuously evolving through cross-functional collaboration.
- Shared the Gas Grassroots Newsletter, resulting in over 7,300 views.
- The Grassroots TV Team produced 68 videos focusing on various aspects of Human Performance, the Energy Wheel, and key life safety events. These included Driving Rodeos, De-escalation Training and Live Action Emergency Drills, Safety Summits, and other organizational learning-based videos. Due to the success of these efforts, a Gas Program manager received the PG&E Sibley award at the AGA for Safe Awareness Video Excellence and the de-escalation training was featured in an issue of the AGA magazine.

Figure 10 – Grassroots Safety Meeting Attendees and Grassroots TV Photos

III. Process Safety

Process Safety Management[8] focuses on preventing low frequency, high-consequence incidents and mitigating the consequences from these incidents. The Process Safety Management System consists of four foundational areas (Figure 11): Commit to Process Safety, Understand Hazards and Risk, Manage Risk, and Learn from Experience. The Process Safety Management System is used for engineering new facilities, modifying existing facilities, maintaining equipment, and strengthening safe operation. PG&E is improving process safety performance by strengthening each of the four foundational areas.

Figure 11 – The PG&E Process Safety Management System

The Process Safety Management System is well integrated within the enterprise-wide PSEMS [see *Section I.3 PG&E Safety Excellence Management System* and Figure 12] to safely manage the planning, construction, operation, decommissioning, and maintenance of gas assets and associated activities, through defined processes and controls, as well as to foster the safe, reliable, affordable, and clean delivery of natural gas.

Figure 12 – The PG&E Safety Excellence Management System

2025 Process Safety Highlights

Commit to Process Safety: Guided by the elements set by the Center for Chemical Process Safety, PG&E's continued commitment to implement process safety aligns with API Recommended Practice (RP) 754 *Process Safety Performance Indicators for the Refining and Petrochemical Industries*.[9] To help

Gas T&D operate and maintain safe facilities and consistently implement process safety practices, the Gas Process Safety team continued to review new and updated procedures and standards last year.

In addition, Gas Process Safety supported the enterprise PSEMS and Gas OSCC with the deployment of the PSEMS and promoting process safety culture improvements. The PSEMS prevents injury and illness by systematically managing processes, assets, and occupational health. Process safety is a key pillar to the PSEMS (see Figure 12) and the Gas Process Safety team contributed their Process Safety Management expertise and experiences during the development of the PSEMS framework, elements, and manual. As part of the PSEMS deployment, the Gas Process Safety team worked with Electric Operations Substation, Transmission-Line, and Power Generation teams to deploy process safety within their line of businesses and integrate into Propel, a business and technology modernization program that is intended to standardize our business processes, enable innovation, and unlock value across our core business functions as we move into a new version of SAP. Lastly, as part of Stakeholder Outreach within Gas T&D and Engineering, in 2025 the Gas Process Safety team published quarterly Process Safety Newsletters, conducted Process Safety Learning Sessions, and hosted Overview of Process Safety training sessions.

Understand Hazards and Risk: Process Safety Management is a key component in reducing PG&E's operational risk exposure. In 2025, the team continued to focus on maturing design risk assessments, standardizing and simplifying project design-phase Process Hazard Analysis (PHA) activities and checklists, and conducting complex project and facility PHAs. Identifying hazards and providing effective safeguards (layers of protection) to improve safety and reduce the risk by answering the five process safety questions and addressing the energy sources (see Figure 13) helps Gas T&D and Engineering understand and manage the risks associated with gas engineering designs or facilities activities.

In 2025, Gas Engineering conducted PHAs for 100 percent of the 440 applicable projects; 328 in gas distribution and 121 in gas transmission.

Figure 13 – Gas Process Hazard Analysis (PHA) Process

Manage Risk: In 2025, risk mitigation efforts included:

- MOC (Figure 14) process improvements;
- PHA/PSSR (Project Specific Safety Risk) process improvements:
  - PHA and PSSR procedures, waivers, and web-based-training (WBTs);
  - PHA and PSSR quality assurances (QAs);
- Safe Work Practices process improvements:
  - Human performance – Pre-job safety briefing AFI;
- Overview of Process Safety training improvement;
- High energy line of fire – enterprise JHA program development;
- Clearance Process (Elevated Review Process [ERP], Metrics, Risk & Readiness Review);
- Development of Station Safety Critical Equipment (SCE) list and Impermeant Procedure;
- Developed the purging exclusion zone criteria; and
- Propel integration.

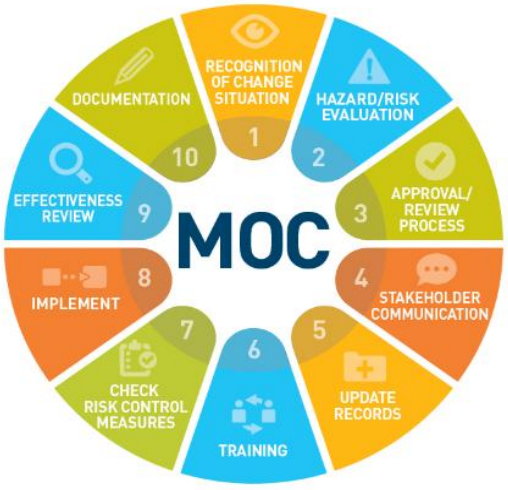


Figure 14 – Gas MOC Process

The focus of the MOC program is on the evaluation of changes in operations, procedures, standards, facilities, materials, or organizations to identify hazards and to provide a framework so that associated risks are effectively managed. MOC is designed to promote changes that achieve their intended purpose without compromising workforce, public, or environmental safety.

The Gas Process Safety team also continued to update the PSSR checklists in 2025. To confirm identification and mitigation of risk prior to tie-ins, Gas Engineering conducted PSSRs for 100 percent of the 128 applicable transmission projects.

Additionally, in 2025, the Gas Process Safety team conducted or supported the following Safe Work Practices improvements:

- **Safety Critical Equipment (SCE) Development:** Collaborated with PHA teams to create SCE lists for gas processing and compressor facilities to allow for risk management before project execution, using the criteria for identifying SCE.
- **Elevated Review Process (ERP) Gas Clearance Criteria:** Supported the development of the ERP Gas Clearance Criteria, adding it to the existing clearance process for medium- and high-risk clearance work.
- **Job Hazard Analysis (JHA) Program:** Collaborated with Enterprise Safety team to develop JHA draft procedure and process based on the high energy line of fire. Assisted in piloting the program by developing select JHAs.

- **Updated Reference Document:** In support of a corrective action from a 2024 incident, the Process Safety team developed a reference document to define exclusion zones for gas release such as during our purging processes.

To support PSEMS, process safety is now being rolled out Enterprise wide. The Process Safety team continues to work with Electric Engineering on effective implementation of process safety tools and has begun collaboration with Power Generation to identify opportunities as well. As part of this effort the Process Safety team has also identified opportunities to integrate process safety with Propel. Though Propel is still in the developing stage, this integration would not only bring much more control and visibility to the PHA/PSSR processes, but it would also build a standard for the rest of the enterprise functional areas as they begin their process safety journeys. Finally, Gas Process Safety revised the Overview of Process Safety training and expanded the list of profiled employees to reach a larger population within Gas T&D and Engineering, as part of our effort to continuously improve and mature our process safety.

Learn from Experience: To continuously improve in process safety, Gas Process Safety engineers support incident investigations and cause evaluations based on incident scope or severity. Lessons learned from these incidents are shared through Process Safety Moments during DORs or other senior leadership platforms. In 2025, Gas T&D and Engineering stayed on the journey of Process Safety Management maturity. Gas T&D and Engineering continued to be compliant, per a third-party assessment, with the intent of API RP 754 and Process Safety Performance Indicators, demonstrating a commitment to incident prevention. The Process Safety Indicator (PSI) Dashboard is based on a pyramid framework from the most serious incidents (Tier A) at the top to leading indicators, such as issues indicating operating discipline or management system concerns (Tier D), at the bottom of the pyramid (Figure 15). The PSI Dashboard drives ownership and accountability so that leading indicators (Tier C and D) are proactively identified and acted upon to reduce the likelihood of a major gas incident (GI) (Tier A and B) that can lead to serious injuries, fatalities, or cause significant interruption to the gas business.

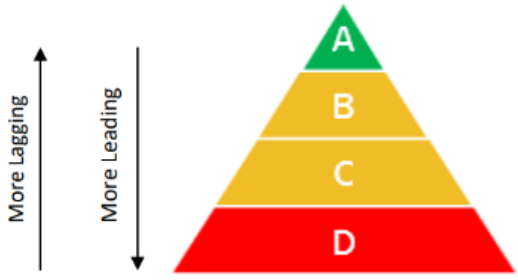


Figure 15 – Pyramid Framework for PSI Dashboard

In addition, in 2025, the Gas Process Safety team continued to improve the PSI Dashboard functionality, conduct trend analysis for the leading and lagging indicators, and aligned the various leading and lagging indicators metrics among the individual PSI Dashboard Tier levels A through D against the PSEMS elements.

Finally, the Gas Process Safety team continued to identify GI and Process Safety Near Misses and supported further development of the Process Safety Near Miss Program to align with the Gas and enterprise-wide Near Hit Program. The Gas Process Safety Near Miss Program's mission, guided by the Safety Principles and Keys to Life, is to substantially advance the enterprise-wide engagement in the reporting, sharing, and dialogue of Near Miss and hazardous events to reduce the risk of employee and public safety incidents.

IV. Gas Leak Abatement Plan

On January 22, 2015, the CPUC issued the Order Instituting Rulemaking (OIR) (R.) 15-01-008 to implement the provisions of Senate Bill (SB) 1371 (Statutes 2014, Chapter 525). SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities consistent with Public Utilities Code § 961(d), § 192.703(c) of Subpart M of Title 49 of the Code of Federal Regulations (CFR), the Commission's General Order (GO) 112-F, and the state's goal of reducing GHG emissions. In the June 15, 2017, Decision (D.) 17-06-015, the Commission established:

1. Annual reporting for tracking methane emissions;
2. 26 mandatory best practices for minimizing methane emissions pertaining to policies and procedures, recordkeeping, training, experienced trained personnel, leak detection, leak repair, and leak prevention;
3. Biennial compliance plan incorporated into the utilities' annual Gas Safety Plans, beginning in March 2018; and a
4. Cost recovery process to facilitate Commission review and approval of incremental expenditures to implement best practices and Pilot Programs and Research & Development.

In August 2019, the Commission's Phase II Decision adopted a restriction on rate recovery beginning in 2025, for methane emissions greater than 20% below the 2015 baseline levels for PG&E and SoCalGas, to reinforce that expenditures authorized to implement their Compliance Plans achieve their intended methane emissions reductions.[10]

Since 2018, PG&E has implemented a series of measures under its previous Compliance Plans, achieving a 52 percent reduction in methane emissions from the 2015 adjusted baseline in 2025. Key measures can be found in the following table:

Table 4 – Key Compliance Plan Measures	
Compliance Period	**Key Measures/Actions**
2018-2019	• Super Emitter Program to accelerate detection and repair of large leaks on the distribution system • Accelerated distribution system compliance survey from five to three years • Cross compression and drafting practices on backbone transmission pipeline projects • Replacement of 100+ high bleed pneumatic devices • Quarterly surveys at compressor stations and storage facilities
2020-2021	• Meter set leak bubble classification and repair prioritization • Project bundling to minimize blowdown emissions • Extending cross compression to local transmission projects
2022-2023	• Lowered super emitter threshold from 10 to 7 standard cubic feet per hour (scfh) prioritizing more large leaks for repair • Leveraging Super Emitter drives for DIMP vintage pipeline surveys • Replacing 10 high bleed pneumatic devices • Extending blowdown strategies to compressor stations and storage facilities
2024-2025	• Further reduction of Super Emitter threshold from seven to six to five scfh prioritizing more large leaks for repair • Replacing 17 high bleed pneumatic devices • Prioritizing repair of outdoor meter set Class B leaks • Transitioning to a component-level methodology for estimating methane emissions at Transmission Metering & Regulating (M&R) stations

In accordance with R. 15-01-008, PG&E is including its fifth biennial Leak Abatement Compliance Plan (2026 Compliance Plan) with the 2026 Gas Safety Plan submittal. The 2026 Compliance Plan covers the years 2026-2027 and describes PG&E's actions, governance processes, and continuous-improvement efforts to reduce methane emissions across its natural gas system.

V. Asset Management

PG&E builds, operates, and maintains natural gas infrastructure to transport, store, and deliver gas to customers in Northern and Central California. There are inherent risks to operating any natural gas system; this is particularly true for PG&E's system as it passes through populated areas and a wide variety of terrain.

The top three operational risks confronting PG&E's natural gas system are a Loss of Containment on Gas Transmission Pipeline, a Loss of Containment on Gas Distribution Main or Service, and a Loss of Containment from a Large Overpressure Event [see *Section V.3 Risk Management Process* for more information]. PG&E's strategy to address these risks through asset management consists of knowing the assets and their condition, understanding the risks for those assets, and developing and implementing risk reduction strategies with the intent to reduce risk in balance with operational performance and cost. Asset Management is part of the PSEMS Element 4: Strategy, Objectives and Planning.

The following sections describe PG&E's asset management system, the asset families, how PG&E Gas manages risk, and the current risk portfolio.

1. Asset Management System

PG&E maintains an asset management system to help drive the business toward achieving its commitment to the safe, reliable, and affordable management and operation of PG&E's gas assets. Using ISO 55001 "Asset management—Management systems—Requirements," PG&E's asset management system focuses on:

- Knowing the condition of the assets;
- Understanding the risks to those assets;
- Implementing asset risk reduction strategies;
- Maintaining asset condition and performance; and
- Balancing asset cost, risk, and performance in pursuit of the asset management strategic objectives.

The Gas Operational Excellence Policy governs the foundation for PG&E's Gas Asset Management system while the vision and strategy for enhancing the system is documented in the Strategic Asset Management Plan. PG&E maintains Asset Management Plans for each of its nine gas asset families and reports regularly to the CPUC on its safety and reliability investments.[11]

2. Asset Family Structure

PG&E continues to use the asset family structure to identify, manage, and mitigate risks faced by the gas assets. The asset family structure also provides a consistent approach for PG&E to address risks. PG&E's nine Gas asset families are illustrated in the figure below.

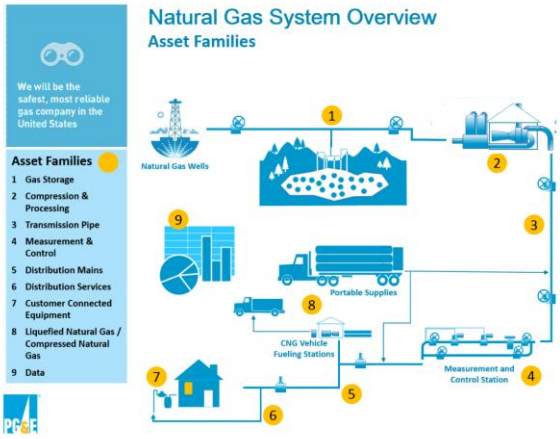


Figure 16 – Natural Gas System Overview - Asset Families

Each asset family has an Asset Family Owner (AFO) who is responsible for understanding the asset condition, the risks to the assets, and developing a risk-informed Asset Management Plan (AMP). An AMP is a living document that maintains a forward-looking, five-plus-year horizon for the management

of gas assets and is continuously updated as conditions evolve. For 2025 changes to PG&E's AMPs, please see Attachment 03.

The AFO leads the preparation of the AMP for each asset family that describes:

- Asset inventory and condition;
- Asset threats and risks;
- Desired state for the assets and strategic objectives for achieving desired state;
- Programs and risk mitigations; and
- Areas for continual improvement.

AMPs are living documents that evolve as new asset or risk management information becomes available. The following sections summarize the types of assets in each family, the function these assets serve in the gas system, and the progress towards achieving long-term goals.

a) Gas Storage

Presently, the Gas Storage Asset Family includes PG&E-owned and operated underground natural gas storage facilities at McDonald Island, Los Medanos, and Pleasant Creek. The primary assets within this family include 106 storage wells, 16 miles of transmission pipe, well controls for all injection and withdrawal wells, and 3,404 acres of storage reservoirs with over 51.1 billion cubic feet (Bcf) of working gas capacity.

Figure 17 – Rig and Well Platform

The United States (U.S.) Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) oversees Underground Gas Storage (UGS) for operators; their rules include adoption of the API's RPS 1170[12] and 1171[13] outlining requirements around risk and integrity management, design standards, emergency response, and training. For operators in California, UGS is also regulated by the California Geologic Energy Management Division (CalGEM). More recently, CalGEM has imposed additional requirements, including requirements for elimination of a single point of failure that necessitates modified well design and construction and other operational changes, such as inspection methodology and increased reporting. In 2025, all active gas storage wells are compliant with 14 CCR *§* 1726.5, which requires dual barrier construction as required by CalGEM – a configuration that significantly impacts available well capacity and reduces the well withdrawal rates on the project by approximately 40 percent. Also consistent with CalGEM's requirements, PG&E has proposed a risk-based reinspection cycle to CalGEM following the baseline inspection and conversion to dual barrier; a decision from CalGEM remains

pending.[14] Additional regulatory decisions related to gas storage continue to be promulgated and are expected to increase and evolve in the coming years in the state of California.

In the CPUC decision D.19-09-025 in PG&E's 2019 Gas Transmission and Storage (GT&S) Rate Case, the Natural Gas Storage Strategy (NGSS) was adopted. PG&E solicited a buyer for the Pleasant Creek Storage Facility and in July 2023, PG&E submitted a response California Public Utilities Code section 851 filing to the Commission for which was approved. PG&E is currently working with the buyer to complete the sale. Further, the 2023 General Rate Case (GRC) Final Decision (D.23-11-069) approved PG&E's request to retain Los Medanos and continue to operate the facility as storage. As part of the decision, PG&E was also approved to move forward with a compressor replacement project given the long-term need for UGS in Northern California.

The Gas Storage Asset Management Plan describes the strategy for mitigating and managing risk for this asset family and achieving the established asset management objectives. Examples of key objectives included in the Asset Management Plan are shown in Table 5.

Table 5 – Gas Storage Asset Management Plan Strategic Objectives and Progress To-Date

Overall Objective/Goal	Progress Towards Goal
Complete baseline well production casing assessments on 104* wells by 2023 ***13 Wells Plugged & Abandoned from 2017-2024, for a net remaining wells of 106**	Number of baseline assessments performed: 2020: 20 wells 2021: 17 wells 2022: 18 wells 2023: 22 wells 2024: N/A – 100% baseline inspections completed in 2023 2025: N/A – 100% baseline inspections completed in 2023
Evaluate and incorporate Well Risk & Integrity Management Plan (WELL) enhancements	2020: Reviewed and revised WELL with sections re-rewritten as either standards, procedures, or guidance. 2021: Published WELL Rev 6, TD-4870M. 2022: Published necessary updates to TD-4870M. 2023: Restructured and published necessary updates to TD-4870M. 2024: Publication of updates to Gas Storage Asset Management Manual, TD-4870M, continued web-based training development for TD-4870M (8 published). 2025: Annual review and made necessary updates to TD-4870M.
Assess work on Non-HCA Storage transmission pipeline with support of the Transmission Integrity Management Program (TIMP)[(a)]	2020: Installed single line 1.6 miles and removed 2.6 miles of dual lines transmission pipe on the west side of Whiskey Slough. 2021: Installed single line 1.1 miles and removed 2.2 miles of dual lines transmission pipe on the north side of Turner Cut. 2022: Completed Turner Cut South Pipe replacement project. 2023: No storage pipe projects completed. 2024: Approximately 1 mile of non-HCA pipe at McDonald Island successfully hydrotested; completed pipe replacement work to accommodate future drilling activities. 2025: No storage pipe projects completed.
Continue PHA and PSSR on all well, surface equipment, and pipeline in storage asset family	Number of PHAs and PSSRs complete: 2020: 38 PHAs, 15 PSSRs 2021: 36 PHAs, 14 PSSRs 2022: 34 PHAs, 20 PSSRs 2023: 21 PHAs, 12 PSSRs 2024: 17 PHAs, 77 PSSRs (Ramp up of PSSRs due to change in process for cleanup) 2025: 1 PHA, 55 PSSRs (Ramp up of PSSRs due to change in process for cleanup)

(a) Pipe within the storage asset family boundary that is non-HCA is subject to the highest internal corrosion threats within the system due to the nature of processing. The Storage Asset Family partners with the TIMP program to employ the appropriate inspection techniques to support the safe operation of these facilities at UGS Facilities.

The Gas Storage Asset Management Plan describes these objectives in more detail.

b) Compression and Processing

PG&E's Compression and Processing (C&P) facilities move gas from receipt points to customer delivery locations and provide for injection and withdrawal of gas at PG&E's UGS facilities. Gas processing equipment provides gas that is sufficiently dehydrated and odorized so that it can be transported to the gas T&D systems, meeting quality requirements. This asset family includes eight transmission compressor stations. Storage compressors are also installed at PG&E's three underground storage facilities.[15] Major assets include 40 Company-owned compressor units, as well as associated equipment such as filter-separators, odorizers, pumps, motor control centers, and station piping, among others. C&P facilities are critical in maintaining the reliability of the gas system.

Figure 18 – Delevan K-1 Compressor Unit

The C&P Asset Management Plan describes PG&E's strategic objectives related to the C&P assets. Key strategic objectives for C&P assets include the following:

Table 6 – Compression and Processing Asset Management Plan Strategic Objectives and Progress to Date

Overall Objective/Goal	Progress Towards Goal
Maintain total number of compressor unscheduled outages below 202 in 2025.	Improvements seen in 2025 (161 outages as of 12/31/2025) compared to 2024 (227 outages) and 2023 (229 outages).
Complete MAOP reconfirmation (ECA2) and/or pressure (strength) testing activities on at least 50 percent of transmission station mileage by July 3, 2028, as required by CFR 192.624(b)(1).	Completed 14 submittals in 2025.

The C&P Asset Management Plan describes these and other strategic objectives in more detail.

c) Transmission Pipe

The Transmission Pipe asset family consists of approximately 6,410 miles of line pipe (the overall mileage count includes transmission, distribution supply line, and gas gathering pipelines) and major components, such as valves and fittings, used in transporting natural gas.[16] PG&E's Transmission Integrity Management Program (TIMP) governs how PG&E identifies threats and evaluates risks, reduces risk through risk mitigation activities, and assesses integrity performance within the Transmission Pipe asset family. The TIMP is a core foundation of PG&E's ongoing efforts to provide safe and reliable service, consistent with industry best practices and based on federal TIMP regulations.[17]

On December 14, 2023, the CPUC approved PG&E's proposal to update definitions of "distribution center," "transmission line," and "large-volume customer." These changes, commonly referred to as "TransDef," allow for the reclassification of select assets from Transmission to Distribution. PG&E's implementation of this change, in accordance with CPUC Decision 23-12-003 to include updates of asset records and work plans, was completed in 2025.

Figure 19 – Line 114 Retrofit Near Livermore

In 2025, PG&E completed six transmission "derate" or "downrate" projects. Transmission pipeline downrates reduce the risk of pipeline failure and allow PG&E to reduce its overall asset risk more efficiently by reallocating costs that would otherwise be spent on transmission integrity work to mitigating risk elsewhere on the gas system. Downrates also provide qualitative greenhouse gas emissions benefits by reducing the magnitude and likelihood of pipeline leaks due to the reduced operating pressure.

The Transmission Pipe Asset Management Plan describes the roadmap for mitigating and managing risk for this asset family and for achieving the established asset management objectives. The plan's objectives and 2025 progress can be found in the following table.

Table 7 – Transmission Pipe Asset Management Plan Strategic Objectives and Progress To-Date	
Overall Objective/Goal	**Progress Towards Goal**
1. Expand the integrity management program to pipelines in HCAs, MCAs, and non-HCA Class 3 & 4 by end of 2034.	• 91.9 percent of the HCA, MCA, and Class 3 and 4 miles of transmission pipe have had baseline assessments. • 67.4 percent of transmission pipe have been assessed using TIMP methods.
2. Execute TIMP to achieve program objectives of zero incidents and full compliance.	• 1 PHMSA reportable incident in 2025 attributable to Transmission Pipe assets (2 PHMSA reportable transmission incidents total). • Completed 145 miles of 2025 HCA Assessment credit mileage. • 0 missed assessments in 2025.
3. Upgrade 65 percent of the transmission system for in-line inspection devices by end of 2038.	• 3 completed ILI upgrades resulting in additional 42.8 miles piggable. • 60.55 percent of the system is piggable (through EOY 2025). • In-Line Inspection – inspected 549.36 miles in 2025. • See *Section V.5.g In-Line Inspection* for more information.
4. Manage the Corrosion Control system and practices to further reduce the time-dependent corrosion risks by end of 2034.	• Cathodic protection (CP) availability maintained at 93.9 percent in 2025. • Conducted Close Interval Surveys (CIS) on 275 miles in 2025, for a total of 72.5 percent of the system surveyed.
5. Meet 100 percent of system capacity obligations and minimize high risk manual operations in peak day conditions.	• High risk manual operations stable (6 for the 25-26 winter). • 8 of 9 transmission regions meet all expected load conditions. • See *Section V.6.a System Capacity Design Criteria* for more information
6. Update PG&E's gas transmission assets to improve incident mitigation management (IMM) by end of 2030.	• Installed 6 automated valves in 2025. • See *Section V.7.d Valve Automation* for more information.
7. Achieve and maintain a first quartile Damage Prevention program to further reduce transmission dig-ins.	• See *Section V.5.a Damage Prevention* for more information.

The Transmission Pipe Asset Management Plan describes these objectives in more detail.

d) Measurement and Control

PG&E's Measurement and Control (M&C) assets monitor, measure, and control pressure and flow within the gas T&D systems. The assets in this family perform a critical role in system safety by protecting downstream assets from system pressure excursions and gas quality degradation. Additionally, in concert with the C&P asset family, these assets perform a key role in overall system reliability.

Figure 20 – M&C Complex Station-Above Ground

The physical assets within this family include three gas terminals, 329 gas transmission stations, 441 large and medium volume customer type facilities, 103 automated valve sites, 2,280 distribution district regulator stations, and 1,372 farm taps. The asset family also includes odorizers and analyzers along with other equipment that monitors gas quality. PG&E's M&C assets are located above and below-ground, including within vaults. As an example, Figure 20 shows a M&C complex transmission station.

The M&C Asset Management Plan describes PG&E's strategic objectives for the M&C assets. Key strategic objectives for M&C assets can be found in the following table:

Table 8 – M&C Asset Management Plan Key Strategic Objectives and Progress to Date	
Overall Objective/Goal	**Progress Towards Goal**
Monitor overpressure risk reduction at regulation facilities and reduce risk through continued execution of mitigation programs for common failure mode stations.	Large overpressure (OP) events per year: 2020 – 9; 2021 – 5; 2022 – 9; 2023 – 5; 2024 – 4; 2025 – 7. • Continued installation of secondary overpressure protection devices.
Complete MAOP reconfirmation (ECA2) and/or pressure (strength) testing activities on at least 50 percent of transmission station mileage by July 3, 2028, as required by CFR 192.624(b)(1).	• Completed 14 submittals in 2025.

The M&C Asset Management Plan describes these, and other strategic objectives, in more detail.

e) Distribution Mains and Services

This asset family includes approximately 45,400 miles of distribution main pipeline that connects to the gas measurement and control asset family on the upstream side and transports natural gas to customers throughout the service area. It also includes approximately 3.7 million service lines totaling approximately 35,000 miles of pipeline that deliver gas from the distribution mains to the assets in the Customer Connected Equipment family on the downstream side. Combined, the distribution mains and services asset family comprise approximately 80,400 miles of distribution pipeline – enough pipeline to wrap around the equator of the earth over three times.

Figure 21 – Employee Working on Distribution Main and Service

The Distribution Mains and Services asset family generally begins at the outlet of the Measurement and Control regulator station assets and ends at the inlet of the distribution service shutoff valve, which is where the Customer-Connected Equipment asset family begins. The programs associated with the Distribution Mains and Services asset family are focused on the inspection, maintenance, and replacement or deactivation of Distribution Main and Service assets. PG&E continues to identify and assess threats to Distribution Mains and Services assets using a federal code compliant operational risk model and then works to mitigate those threats in various ways, including through its Distribution Integrity Management Program (DIMP). Key strategic objectives can be found in the following table.

Table 9 – Key Distribution Mains and Services Metrics	
Overall Objective/Goal	**Progress Towards Goal**
Maintain first quartile for third-party gas dig-ins.	PG&E set a third-party dig-in target of 1.03 dig-ins per 1,000 tickets for 2025. In 2025, PG&E experienced 0.80 dig-ins per 1,000 tickets for third-party dig-ins.
Eliminate potential hazards associated with historic pre-1985 plastics by the end of 2049, with consideration of cost-effective electrification.[(a)]	2012: 17.6 miles replaced 2013: 30.7 miles replaced 2014: 32.5 miles replaced 2015: 63.5 miles replaced 2016: 80.4 miles replaced 2017: 95.1 miles replaced 2018: 91.2 miles replaced 2019: 90.1 miles replaced 2020: 87.6 miles replaced 2021: 136.3 miles replaced 2022: 163.9 miles replaced 2023: 84.2 miles replaced 2024: 109.5 miles replaced 2025: 100.3 miles replaced

(a) Includes the Butte Rebuild replacement mileage performed in-concert with the Plastic Pipe Replacement Program (Capital, MAT 14D). This does not include main replacement through other programs such as the Gas Pipeline Replacement Program (Capital, MAT 14A) or the Reliability Main Pipe Replacement Program (Capital, MAT 50A).

The Distribution Mains and Services Asset Management Plan describes associated strategic objectives in more detail.

f) Customer-Connected Equipment

The Customer-Connected Equipment Asset Family is composed of approximately 4.8 million gas meters and associated regulators, shut-off valves, piping, and fittings that connect the gas distribution service to the customer. Customer meters are used to measure gas usage to support the billing function.

Figure 22 – PG&E Employee Working on Customer Connected Equipment

The Customer-Connected Equipment Asset Management Plan provides an overview of the assets, threats to these assets, and efforts underway to manage these threats. The plan presents the asset inventory and an assessment of condition and overview of key risks to these assets. The plan also includes long-term strategic objectives and an overview of the key programs in progress to mitigate these risks. One of the plan's key strategic objectives is included in the following table.

Table 10 – Key Customer Connected Equipment Metrics	
Overall Objective/Goal	**Progress Towards Goal**
Develop and implement residential methane detector strategy by 2030.	• Established an internal PG&E Methane Detector Committee to champion policy and implement internal processes for gas detection safety devices. • Implemented and continued to mature pilot program to test deployment and installation of residential methane detector devices. • Published external webpage to build customer awareness around methane detector devices.

The Customer Connected Equipment Asset Management Plan describes associated strategic objectives in more detail.

g) Liquefied Natural Gas and Compressed Natural Gas

The Liquefied Natural Gas (LNG)/Compressed Natural Gas (CNG) asset family consists of portable assets that provide natural gas supplies utilizing either LNG and/or CNG to offset or supplement pipeline flowing supplies for planned outages, winter peak load shaving, unplanned outages, and emergency situations. The LNG/CNG asset family consists of over 200 portable assets with the inclusion of PG&E owned mobile odorization units, as well as portable cross compression that is primarily utilized to move isolated methane to an adjacent pipeline, reducing overall raw methane emissions during pipeline work. In 2025, there were no loss of containment incidents for portable assets as indicated in Table 11.

Figure 23 – Portable Cross Compression Degassing Isolated Segment of Pipeline into Adjacent Line

Figure 24 – A Large-Scale LNG Injection Site in Dublin, CA Supporting a Planned Gas Outage

The LNG/CNG asset family also includes 33 CNG station assets to supply high pressure natural gas that fuels PG&E and third-party vehicles while also providing gas supply to our portable CNG assets. Since 2014, PG&E has maintained an industry leading inspection program to assure the integrity of its

customers' Natural Gas Vehicle fuel systems. In 2025, 100 percent compliance with this program was achieved. In 2025, PG&E remained 100 percent compliant with PG&E owned natural gas vehicle fueling stations. This compliance was achieved when either the customer submitted a required three-year vehicle certificate of inspection or the customer's fueling privileges were suspended until the inspection was completed. In 2025, there were no significant loss of containment incidents for CNG Station assets.

Table 11 – Liquefied Natural Gas/Compressed Natural Gas Asset Management Plan Strategic Objectives and Progress to Date

Overall Objective/Goal	Progress Towards Goal
Driving towards zero significant LNG/CNG loss of containment incidents	2025: Achieved zero significant loss of containment incidents through continued maintenance, investments, and upgrades of LNG/CNG equipment and assets. Continued LNG/CNG equipment training development and administering, including the LNG/CNG apprenticeship program. Continued improvements in quality control program to verify overall effectiveness of maintenance and training programs for LNG/CNG assets.
Implementing an industry-leading inspection program to improve safety inspection certifications to 100 percent of CNG fuel customer vehicles	2025: 100 percent of natural gas fueling customers authorized to fill at our facilities submitted their three-year cylinder certification in compliance with current Federal Motor Vehicle safety standards.
Reduce risk of portable natural gas transportation traffic incidents by reducing equipment issues through an improved maintenance program	2025: Continued maintenance of LNG/CNG portable over-the-road assets by dedicated fleet mechanics with Transportation Services. Hazardous material transport trailer quality control program continues to be in place to verify overall effectiveness of the below the deck maintenance program.

The LNG/CNG Asset Management Plan describes these objectives in more detail.

h) DATA

Established in 2017, Gas Data Management (GDM) has become an integral part of Safety Management Excellence. Successful management of data as an asset relies on developing and maintaining high-quality data and the recognition that achieving this requires time, effort, and organizational support from leadership and data stewards.

GDM is responsible for the data quality of the Gas Asset Registry (AR), a system to manage and monitor the quality of data representing physical and non-physical assets used to safely operate the gas infrastructure. Since its inception, GDM has enhanced the AR by improving completeness, traceability, and quality of data. In 2019, Gas began to validate mission and business critical data and added data quality monitoring. This monitoring enables PG&E to quantify the quality of asset data in the Gas Asset Registry (SAP and GIS). The strategy to improve and maintain the AR is to address historical and legacy data gaps, introduce controls to data as it is added to the registry and with Mobile As-Builts (MAB), and utilize the Propel deployment to drive accuracy and timeliness of data.

In 2025, the Data Asset Family continued to strengthen controls and advanced data quality through validation programs (data stewardship), system reconciliation (SAP/GIS Alignment), and proactive monitoring dashboards (Strategic Data Plans). As Gas data governance and stewardship capabilities have

continued to mature, further progress is supported by increased alignment with the enterprise data governance framework. Gas remains committed to strengthening its governance practices, and sustained advancement will be enabled through an enterprise-wide approach that reinforces coordination, consistency, and shared accountability.

Key Metrics from 2025 are presented in Table 12. Strategic goals, and progress towards those goals, are listed in Table 13.

Table 12 – Key Data Asset Metrics for 2025

Overall Objective/Goal	Progress Towards Goal to Date
Data Sets Under Management	Vital Few Key Performance Indicators (KPIs, board of directors' level) • 1333 critical datasets have been identified within Gas • 136 datasets have been brought under management in total.
Data Quality Key Performance Indicators (KPIs)	Critical data elements (CDEs) • To date, 126 unique data locations have been identified in 19 different data sources. • Currently, 2,789 CDEs have been collected for critical datasets, including: • 6,212 data quality rules are running monitoring CDEs • 3,243 are meeting or exceeding the set threshold • 1,565 fall below the threshold from 0% to 5% • 1,087 fall well below the threshold greater than 5%

Table 13 – Data Asset Management Plan Strategic Objectives and Progress to Date	
Overall Objective/Goal	**Progress Towards Goal**
Continue Implementation of Data Stewardship in alignment with the Enterprise Data Strategy and reach PSEMS level 4 maturity by the end of 2028.	• Completed training for 8 Business Data Stewards. • Enterprise pivot to a new data stewardship tool will require new training for 2026.
Develop and implement the data governance framework to improve underlying data quality to effectively manage risk outcomes for all Gas asset families by the end of 2028.	• Dataset Scoring Model updated • SDP Datasets Prioritization in progress • 4 quarterly governance meetings completed at functional area level in 2025.
Implement advanced data analytics platform that enables big data analysis and provides actionable insights. Foundational data from SAP, CC&B and GIS to be ingested with Level 2 (reusable) ontology into advanced data analytics platform by end of 2025	• Ingested 25 data ontologies (Foundry) • Developed product creation lifecycle: Ideate, incubate, accelerate, retire. Developing value-stacking framework to improve ROI
Develop and execute an annual portfolio of data quality improvement projects with supporting processes and do so in a way that is strategic, and risk informed.	Developed product tracking. Dashboard development underway. SAP-GIS Alignment (May 2023-Present) • Identification of assets that are in GIS and may not be in SAP. • Enables asset family owner to identify assets where maintenance plans are missing. • Helps build trust with users when looking at like data • For Gas Distribution and Transmission updated. • 125,249 values (records and attributes) previously not aligned between GIS and SAP. • Went from 13.5% to 21.2% matching records, a 7.7% Improvement. Service Installation Date (SID) (2023-Present) • Updated 59,685 previously unknown install dates • Went from 89.5% to 90.1% Matching Records, a 0.6% Improvement, as the ~96% limit with linked records is approached. • ~160K of the targeted ~460K Services do not have a Gas Service Record associated with them, ~4% will require other methods of discovery.

The Data Asset Management Plan describes these objectives in more detail.

3. Risk Management Process

Transporting natural gas involves moving a flammable product under pressure. As a result, risk management is an important part of the natural gas business. PG&E's Enterprise and Operational Risk Management (EORM) team prioritizes risks based on how likely an incident is to occur and how severe it might be. Although the hazards and risks associated with natural gas are inherent, multiple layers of protection placed on top of one another safeguard against the failure of any one layer. Therefore, PG&E builds in multiple layers of protection into Company processes and plans.

To identify and address risk, PG&E follows a comprehensive EORM process. PG&E's EORM plans allow PG&E to manage assets and risks at an enterprise and operational level. PG&E defines "Enterprise Risk" as any risk that could potentially have a catastrophic impact to the Company. PG&E's Board of Directors (BOD) provide oversight for Enterprise Risks through annual and ad-hoc risk reviews.

All operational risks are actively managed at the functional area level, with oversight provided by each functional area's Risk and Compliance Committee (RCC), which meet quarterly at a minimum. However, in 2025, the Gas RCC met monthly. Each functional area's RCC is charged with oversight of risk management activities within the functional area including, but not limited to, reviewing risk assessments, approving risk response plans, and overseeing their implementation.

By assessing and managing risks from PG&E's BOD and Gas RCC, PG&E can better manage the interdependencies and drive for consistency in risk management across the Company. In addition, the EORM team leverages several executive forums[18] to maintain governance of the EORM and awareness of enterprise risks across the executive team. The annual governance plan supports BOD oversight of Enterprise Risks and provides oversight for the remainder of the Corporate Risk Register. Elements of the work plan include risk management program strategy, deep dives, and challenge sessions for specific top risks. This process increases Senior Leadership and BOD engagement in risk-informed decision-making by involving them in decisions as the process unfolds and gives individuals charged with managing specific assets line of sight to other risks across the enterprise.

Gas identifies, assesses, and ranks its risks in a Corporate Risk Register in accordance with EORM guidelines. The Gas risks within the Corporate Risk Register are governed by the Gas RCC. In 2025, PG&E implemented Risk Deep Dive (RDD) sessions twice, as well as Quarterly Operating Reviews (QOR) where Gas risks were discussed with PG&E's senior leadership team. Risks for each asset family identified during an annual risk refresh are captured within the Asset Management Plans, mitigation programs, and work projects. As a result of the annual risk refresh process, Gas identified nine operational risks as part of the Corporate Risk Register for 2025, which have not changed since 2020. These risks are summarized in Table 14.

Table 14 – 2025 Gas Risks in the Corporate Risk Register	
Risk	**Description of Risk and Risk Drivers**
Loss of Containment on Gas Transmission Pipeline	Failure of a gas transmission pipeline resulting in a loss of containment, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas to customers. Failure of a gas transmission pipeline includes both pipeline leak and pipeline rupture. Drivers include: Equipment Failure, External/Internal Corrosion, Incorrect Operations, Manufacturing Defects, Stress Corrosion Cracking (SCC), Third Party/Mechanical Damage, Weather Related and Outside Force Threats, and Construction Threats.
Loss of Containment on Gas Distribution Main or Service	Failure of a gas distribution main or service resulting in a loss of containment, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas to customers. Drivers include: Equipment Failure, Corrosion, Incorrect Operation, Excavation Damage, Material Failure of the Distribution Pipeline or Weld, Natural or Other Outside Force, and Cross Bore.
Loss of Containment from a Large OP Event	Failure of a Gas M&C facility to perform its pressure control function resulting in a large OP event downstream that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and/or the inability to deliver natural gas to customers. Drivers include: Equipment Related and Incorrect Operations.
Loss of Containment on Gas Customer Connected Equipment	Failure of gas customer connected equipment resulting in a loss of containment, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas to customers. Drivers include: Corrosion, Equipment Failure, Incorrect Operation, Material/Weld Fail, Natural or Other Outside Force.
Loss of Containment at Natural Gas Storage Well or Reservoir	Failure at a gas storage well or reservoir resulting in loss of containment, with or without an unplanned ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas to customers. Drivers include: 1st/2nd/3rd Party Mechanical Damage, Incorrect Operations, Casing Wall Loss, Equipment Related, Manufacturing Related Defects, Weather Related/Outside Forces, and Welding/Fabrication Related.
Loss of Containment at Gas M&C or C&P Facility	Failure at a Gas M&C or C&P station resulting in a loss of containment that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas to customers. Drivers include: Incorrect Operations, Welding/Fabrication Related, External/Internal Corrosion, SCC, Third-Party/Mechanical Damage, Weather Related/Outside Forces, Manufacturing Related Defects, and Equipment Related.
Loss of Containment on CNG Station Equipment	Failure of CNG station equipment during operations resulting in a loss of containment that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas to customers. Drivers include: Third Party Damage, Equipment Related, Incorrect Operations, and Corrosion.
Loss of Containment on LNG/CNG Portable Equipment	Failure of LNG/CNG portable equipment during operations resulting in a loss of containment that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas to customers. Drivers include: Equipment Related, Incorrect Operations, Corrosion.
Insufficient Capacity to Meet Customer Demand	Failure to maintain capacity on the system on high demand days. Drivers include: Pipeline Outage, Integrity Finding, Delayed/Deferred Capacity Projects, Inadequate Design, Design Deviation, and Unexpected System Restriction.

Factors impacting more than one risk as a unique risk driver, or a component of an existing risk driver, are called Cross-Cutting Factors. As such, these factors can impact the likelihood or consequence of a risk event. The Cross-Cutting Factors are owned by a single functional area, with other impacted functional area(s) providing their input and subject matter expertise. These factors also follow the EORM process. Gas is impacted by several Cross-Cutting Factors owned by other functional areas as displayed in the table below.

Table 15 – Enterprise Risk Management: Cross-Cutting Factors	
Cross-Cutting Factor	**Description**
Seismic	Seismic events can be a significant driver of failure in all functional area assets. Seismic events contribute to the likelihood of asset failure events and to the associated safety, reliability, and financial consequences of those events.
Cybersecurity Incident	A coordinated malicious attack purposefully targeting PG&E's core business functions, resulting in loss of control of Company information or systems used for gas, electric, or business operations. The consequences of a cyber-attack are potentially catastrophic and could impact the safety and reliability of PG&E's operational systems.
IT Asset Failure	Failure of IT systems or infrastructure, resulting in outages, system unavailability for mission critical assets impacting operations, or the ability to support public safety events.
Records and Information Management (RIM)	The risk of not having an effective RIM program may result in the failure to construct, operate, and maintain a safe system and may lead to property damage and/or loss of life.
Physical Attack	Incidents related to break-ins, vandalism, theft, fraud, assault, and threats against PG&E's workforce and assets.
Emergency Preparedness and Response	Examines the drivers and consequences of inadequate planning or response to catastrophic emergencies. Inadequate emergency planning or response could have significant safety, reliability, and regulatory impacts.
Climate Change	Climate change presents ongoing and future risks to PG&E's assets, operations, employees, customers, and the communities it serves.

Through external regulatory changes, PG&E continues to improve its risk management process and is an active participant in CPUC proceedings to advance a "risk-informed" process. In D.14-12-025, the CPUC adopted a risk-based decision-making framework into the Rate Case Plan for energy utilities. The framework includes the Safety Model Assessment Proceeding (S-MAP) and the Risk Assessment and Mitigation Phase (RAMP). S-MAP's focus is on the models used by each utility to evaluate risk, with the intent of developing a single model for all utilities. RAMP's focus is on risk mitigation, alternatives analysis, cost-benefit ratio, and a quantitative measure of expected risk reduction. D.22-12-027[19] replaced the previous 2018 S-MAP Settlement Agreement with a modified Risk-Based Decision-Making Framework document that details the minimum requirements for an IOU's RAMP report.

A key change in the decision is a shift from a Multi-Attribute Value Function (MAVF) approach to a Cost-Benefit Approach (CBA) that includes standardized dollar valuations of safety, electric reliability, and gas reliability consequences from risk events. This change, along with other Risk-Based Decision-Making Framework refinements made in the decision, are intended to further increase transparency, participation, and accountability into how safety risks for energy utilities are managed, mitigated, and minimized. PG&E incorporated the new requirements from this Decision into the 2024 RAMP report (A.24-05-008) filed in May 2024, which is the initial phase of PG&E's 2027 GRC (A.25-05-009, filed May 15, 2025). The key updates reflected in the 2024 RAMP report are the conversion to the CBA for risk measure and the transition from Risk Spend Efficiency (RSE) to Cost Benefit Ratio (CBR) calculations for mitigation analysis.

4. RECORDS AND INFORMATION MANAGEMENT

PG&E's Information & Records Governance (IRG) Program's focus is to reduce risk and increase trust in the Company's information and records by providing clear governance, change management and process improvement, and effective technology and tools. This includes deployment of consistent, integrated processes that support records development associated with operational safety, regulatory compliance, and knowledge management. IRG works with all of PG&E to assess and inventory physical and electronic records and implement tools to manage the lifecycle of records. Examples of IRG accomplishments in partnership with the Gas functional area in 2025 include:

- Continued physical records remediation in field offices and provided local support during decommissioning and reconfiguration of PG&E sites.
- Validated 354 (65 percent) of 545 Gas records in the Enterprise Records Inventory and remediated 38 (58 percent) of 57 Gas records risks.
- Migrated 232,951 files from ELS Gas to Documentum CRM cloud after analyzing and cleaning up 311,000 files. This move allows Gas business users to upload files into correct version trees, reducing safety risks from inaccurate drawings.
- Migrated the Technical Information Library (TIL), including all Gas TIL records, to Documentum CRM cloud.
- Destroyed 1,007 boxes of eligible inactive Gas records through the physical records disposition process.

Table 16 – Gas Records and Information Management Roadmap Highlights

Roadmap Projects & Programs	Roadmap Drivers
Documentum Repository Consolidation	• Documentum stability and support, improved functionality, and new features. • Simplified data structure to support functional implementation. • PG&E's Records Information Management standards (GOV-7000 series).
IRG Program Compliance	• Information Governance Maturity Model & Framework • PG&E's Records Information Management standards (GOV-7000 series) • California Privacy Rights Act (CPRA)
Third-Party Compliance Audits	
Information Governance Maturity Assessments	
Physical Records Disposition Execution	
Data Disposition	

IRG maintains comprehensive five-year roadmaps listing projects and initiatives in support of PG&E's mission and goals. Table 16 highlights key IRG projects and programs, with the drivers for work impacting the Gas functional area in 2026.

5. Mitigating the Risk of Loss of Containment

PG&E takes a proactive approach to reduce the risk of loss of containment or the unintended release of natural gas. The mitigation programs and projects to address loss of containment vary significantly in size and scope, from actively promoting "811 Call Before You Dig" and installing pipeline markers over the assets as visual identifiers, to inspecting, testing, and replacing assets that may be deemed beyond their useful lives. PG&E remains focused on identifying the right work to protect the public from a loss of containment incident.

a) Damage Prevention

Damage Prevention consists of multiple workgroups collaborating to educate excavation contractors and homeowners about safe excavation practices near underground infrastructure. Activities are reviewed continuously throughout the year. Described in the following sections, they include Public Awareness, Dig-in Reduction Team (DiRT), Locate and Mark, Standby Governance and Pipeline Patrol.

Damage Prevention includes marking the field location of underground facilities, as requested, through the Underground Service Alert (USA) system (commonly referred to as 811), USA ticket management, investigations associated with excavation damages (commonly referred to as dig-ins) and damage claims, monitoring excavations in proximity to critical infrastructure, and Public Awareness. The marking of underground utilities is governed by California Government Code Section 4216 et seq. and the process is driven by regulatory requirements and industry best practices. Table 17 describes other key Damage Prevention programs.

Table 17 – Damage Prevention Programs	
811 Ambassador	Every few minutes, a dig-in (utility strike) occurs in the U.S. Dig-ins can cause damage to people, property and the environment. Dig-in incidents pose a significant risk to public and personnel safety. These incidents are caused by negligence but can be prevented through education and enforcement. Having an 811 ticket and utility markings decrease dig-ins. 811 tickets are required by the California One Call Law. In 2025, approximately 51% of 3rd Party contractors damaged PG&E gas lines because they failed to obtain an 811 ticket prior to digging. In 2025, homeowners and commercial excavators were responsible for approximately 1,179 dig-ins to PG&E's underground gas pipeline system. Of those dig-ins, 51% of them had no 811 ticket, meaning the homeowner and/or contractor did not request a ticket for utility marking. In 2025, 92% of the 811 Ambassador reports had no 811 tickets; there were 320 811 Ambassador reports with No 811 tickets which is a potential dig-in savings of $1,120,000 in distribution service for the Company. The goal of the 811 Ambassador program is to empower all Company personnel to be advocates for damage prevention and public awareness of safe digging practices. It provides a way for PG&E employees to speak up when they observe an unsafe excavation with no delineation or markings. All PG&E employees are 811 Ambassadors. In 2025, an 811 Ambassador Application was installed on every coworker's cell phone, allowing employees who observe excavation without required marks to notify the Damage Prevention team through the 811 Ambassador Application. Once an unsafe digging report is made, a Dig-in Reduction Team (DiRT) member is notified to assess whether the excavation complies with California's One Call Law. If the excavation is found to be in non-compliance with California's One Call Law, the DiRT member takes several actions. They request all excavation be stopped, educate the excavator about the requirements of California's One Call Law and the reason for the non-compliance, provide excavation safety materials, and instruct the excavator to correct the non-compliance activity prior to continuing any excavation.
Damage Prevention Institute	The Common Ground Alliance (CGA) created the Damage Prevention Institute (DPI). The goal of DPI is to identify and develop best practices in excavation safety. PG&E sits on the DPI advisory committee and actively participates in developing industry best practices. DPI sets the safety criteria that second-party contractors are required to meet to be eligible to do work on behalf of the Utility. Having PG&E coworkers and PG&E contractors participate in DPI is one way that PG&E is helping to make communities safer. PG&E requires its contractors excavate on behalf of PG&E to maintain the DPI accreditation. PG&E acknowledges all contractors who practice safe excavation and monitors offenders who fail to demonstrate safe practices. Unsafe contractors are unable to perform work on behalf of PG&E.
Procedures, Guidance and Training	Providing clear and concise instruction around dig-in prevention measures like troubleshooting "difficult to locate" facilities, documenting field activities, and how to properly respond to a USA ticket. PG&E has continued to revise Locate and Mark procedures with lessons learned and feedback from field employees to increase quality and safety. Also in 2025, a new version of the Locate and Mark Field Training Guide (FTG) was released for use by field employees. The new FTG links human performance tools with best practices and troubleshooting techniques to facilitate the best possible performance from locators in the field.

Since 2014, PG&E has improved its "Shut-In the Gas Performance," which tracks the Company's ability to quickly stop the flow of gas when the Company is notified of potentially dangerous public safety events such as dig-ins, impacts to meters from vehicles, pipe ruptures, explosions, or material failures. The Shut-In the Gas Performance specifically measures the number of minutes required for a qualified PG&E responder to arrive onsite and stop the uncontrolled flow of gas from PG&E's distribution network.[20] PG&E measures performance for damages impacting either gas service lines or meters/risers (Services) or damages impacting gas mains. Plan of Reorganization (D.20-05-053) called for the development of Safety and Operational Metrics to be used in conjunction with the adopted Enhanced Oversight and Enforcement Process to advance the progress that is being made on key safety and operational metrics. In 2022, PG&E began reporting the median Shut-In the Gas Performance versus the average. As seen in Table 18, in 2025 PG&E's median Shut-In the Gas Performance exceeded its target with 30.6 minutes for services and 81.9 minutes for mains. PG&E will continue its efforts to improve its Shut-In the Gas Performance.

Table 18 – Shut-In The Gas Performance (Median Number of Minutes)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025 Target
Svcs.	38.0	40.0	37.0	36.0	37.2	36.8	36.7	36.3	36.8	35.3	34.2	30.6	**39.8**
Mains	97.0	87.0	87.0	89.0	76.1	76.0	79.2	79.1	82.1	80.0	83.6	81.9	**87.4**

Since 2014, PG&E has improved its overall make safe performance on events involving services by 19 percent and events involving mains by 15 percent.

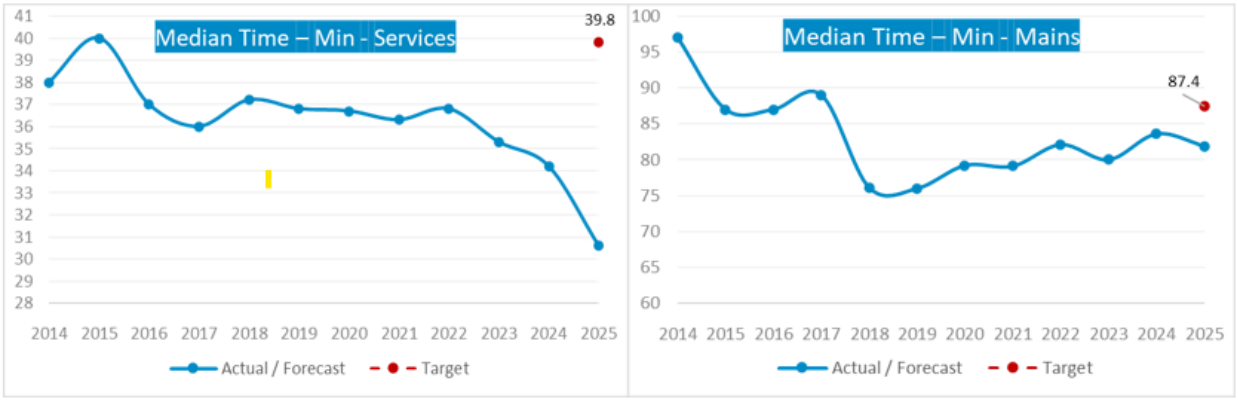
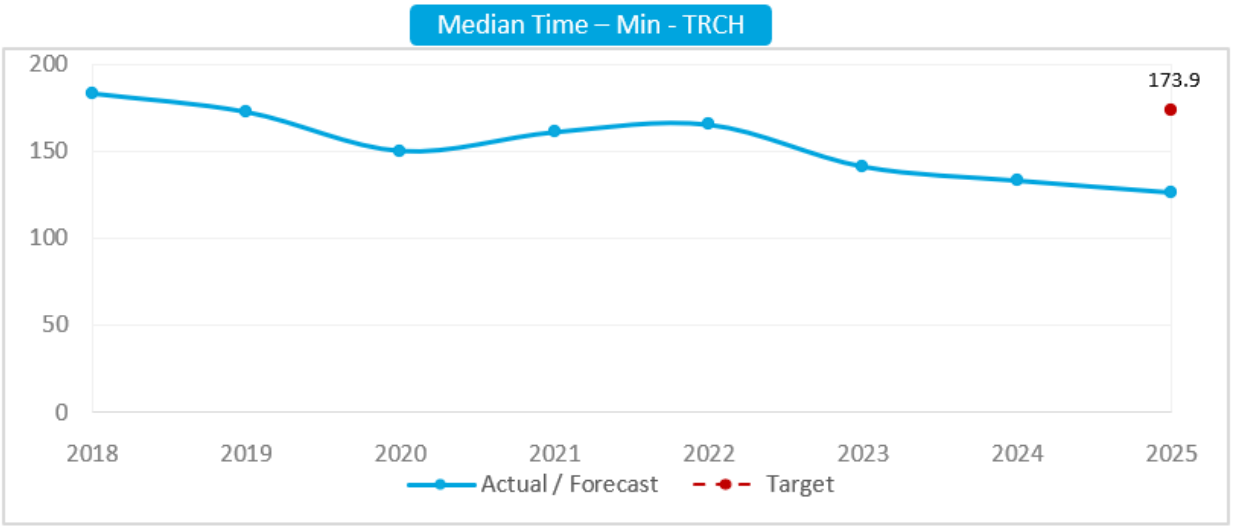


Figure 25 – Shut-In the Gas Performance

In addition to Shut-In the Gas performance, PG&E began measuring the Time to Resolve Hazardous conditions (TRHC) in 2022 as part of the Safety Operational Metrics. This metric measures the median response time to resolve a Grade 1 leak. As seen in the following table and graph, PG&E's median Time to Resolve Hazardous Condition performance exceeded its target with 126.0 minutes for 2025, which was a five percent improvement compared to the 2024 median time of 132.9 minutes.

Table 19 – Shut-In The Gas Performance (Median Number of Minutes)									
	2018	2019	2020	2021	2022	2023	2024	2025	2025 Target
TRCH	183.4	172.7	150.1	161	165.3	141	132.9	126	**173.9**



i. Public Awareness

PG&E's Public Awareness Program conducts educational outreach activities for excavators, local public officials, emergency responders, and the public who live and work in PG&E's service territory. The program communicates safe excavation practices, required actions prior to excavating near underground pipelines, availability of pipeline location information, and other gas safety information through a variety of methods throughout the year including bill inserts, e-mails, brochures, mass media advertising and press releases.

PG&E conducted 470 "811 Call Before You Dig" contractor workshops, reaching 5,829 attendees at 550 companies

PG&E communicates gas safety information continuously throughout the year, and in 2025, reached approximately 3 million customers who receive paper bills as well as sent approximately 3 million e-mails to customers who receive paperless billing. In addition to the bill inserts and e-mail campaigns, PG&E sent targeted direct mailers to over 300,000 businesses and residences within 1,000 feet of a PG&E gas transmission pipeline, explaining their proximity to the transmission line, information about how to locate nearby gas pipelines, damage prevention measures (811), how to identify gas leaks, and what to do in the event of a gas leak. Additional targeted mailings were sent to school administrators, excavators, emergency responders, public officials, landscapers, sewer and plumbing companies, farmers, master meter accounts, and those who live or work near PG&E's storage and compressor facilities. Table 20 identifies highlights from the Public Awareness Program's 2025 activities.

Table 20 – 2025 Public Awareness Program Highlights
Mailed educational postcards to homeowners who recently called 811, thanking them for keeping their communities safe. Separate postcards were sent to their neighbors explaining 811 and what the marks on the ground mean. This outreach was done on a weekly basis in areas with high dig-ins, resulting in 7,954 touchpoints.
Executed 6 different social media campaigns targeting homeowners and contractors throughout PG&'s service territory, promoting the importance of calling 811 before digging. These campaigns resulted in over 4.7 million impressions.
Completed 12 bilingual 811 workshops, with 400 participants, in partnership with local Spanish language radio stations.
Continued to conduct targeted outreach in cities with a high number of dig-ins. The outreach included job site visits, responding to dig-ins and issuing notices of unsafe excavation. These targeted efforts resulted in over 8,628 field visits by Dig-in Reduction Team (DiRT) Investigators

ii. DIG-IN REDUCTION TEAM (DIRT)

PG&E continues to push for improved performance in dig-in prevention by conducting factual investigations of excavation damage to PG&E's facilities, identifying process improvements to reduce damages, and actively pursuing cost recovery from excavators responsible for excavation damage. The DiRT is part of a proactive program that directly and positively affects public and employee safety by striving to reduce the number of excavation damage incidents through outreach, education, and incident investigations. PG&E's Dig-In Reduction programs are instrumental in managing the number of third -party gas dig-ins per USA tickets.

Table 21 provides information on various dig-in prevention projects or process improvements.

Table 21 – Dig-In Reduction Team Programs Under Damage Prevention	
PG&E's Commitment to Safety	**Promoting Safety**
DiRT Investigations	Deploys investigators to oversee and enhance PG&E's ability to investigate dig-ins, patrol active excavations, and intervene when unsafe excavation activities are identified.
Pipeline Patrol	Identifies and intercepts surface threats to the transmission system via aerial and ground patrolling. Pipeline Patrol notifies DiRT as needed. DiRT will perform tasks listed above, as appropriate.
811 Workshops	Conduct safe digging workshops throughout the service territory.

iii. LOCATE AND MARK PROGRAM

The Locate and Mark Program is designed to mitigate the potential risk of damage to underground facilities by identifying and marking assets for potential excavators within a two working-day window. Federal pipeline safety regulations[21] and California state law[22] require that PG&E belong to, and share the cost of, operating the regional "one-call" notification system. Builders, contractors, and others

planning to excavate must use this system to notify underground facility owners, like PG&E, of their plans to excavate. PG&E then provides the excavators with information about the location of its underground facilities, including natural gas, electric, and fiber optic. Information is typically provided by having a PG&E locator visit the work site and place color-coded surface markings to show where underground pipes and wires are located. Because of its large service territory, PG&E belongs to two regional notification centers which share a common toll-free, 3-digit "811" telephone number. The California one-call systems are commonly referred to as "USA." In 2025, PG&E received over 1.6 million USA ticket notifications, an increase from approximately 1.4 million USA ticket notifications in 2024.

Figure 26 – PG&E Coworker Marking a Gas Main and Service

Human Performance Training has been identified as an effective method of fostering safety and promoting procedure usage and adherence with Locate and Mark employees. This training has been deployed for all field employees, and its tenets have been incorporated into the newly refreshed Locate and Mark Field Training Guide.

iv. Standby Governance

Standby Governance is part of PG&E's internal damage prevention process to meet requirements of 49 CFR Part 196. Excavators working near PG&E high-priority or critical facilities are mandated to follow safe excavation practices per California Government Code § 4216 as well as PG&E procedures.

Standby is a free service provided to excavators. Standby inspectors serve as an objective representative of the utility on site to observe and protect PG&E facilities.

Figure 27 – Standby Crew at Work During Excavation

The standby role goes well beyond simply observing and reinforcing safe excavation. It is important for a standby inspector to understand the complexities of each job to foster the safety of the public, coworkers, and PG&E's assets. The standby inspector is familiar with general safe excavation practices, PG&E procedures, and how to apply them. Additionally, a standby inspector will intervene to stop work if they identify any unsafe activities that may jeopardize PG&E facilities, the crew, or the public.

The Standby Governance Team supported 5,467 standby jobs in 2025. While each standby was conducted to protect PG&E's critical infrastructure, each standby also provided an opportunity to build relationships with excavators and to educate the excavator community on safe digging practices.

v. PIPELINE PATROL

Pipeline Patrol is a federally required activity designed to protect the integrity of PG&E's gas transmission facilities from external threats while supporting public safety. Patrol is performed both by air and ground by operator-qualified personnel who observe surface conditions on or near the rights of way of buried pipelines. Patrollers identify and respond to excavation activity (e.g., digging, ripping, boring, blasting, etc.) to notify excavators that they are digging in the vicinity of pipelines, and in the case of unauthorized digging, to educate and direct the use of the Underground Service Alert System (USA).

Patrollers also report on surface conditions that could cause damage to Company facilities, such as land movement, or conditions that could cause a change in class location, such as new construction, that may affect identification of High Consequence Areas.

PG&E primarily utilizes aerial methods to conduct patrols, with ground personnel dispatched to investigate observations made from the air. Special patrols may also be performed following natural disasters or other incidents as necessary. Aerial patrols provide real-time knowledge of on-the-ground activities, and their surveillance helps PG&E identify and stop unsafe excavation practices before dig-ins occur.

Figure 28 – Example of Land Movement

Figure 29 – Patrol Fixed Wing Aircraft

Figure 30 – Patrol Helicopter

PG&E patrols use a combination of fixed-wing aircraft and helicopters. In 2025, 54 percent of observations were related to excavation, 16 percent were related to agriculture, 8 percent were immediate threats, and the remaining 22 percent were related to include right of way (ROW) encroachments, geohazards, and other miscellaneous observations requiring further ground evaluation.

b) Pipeline Markers

Pipeline Markers are signs on the surface above or near natural gas pipelines and are located at frequent intervals along the pipeline ROW. Markers and indicators are important damage prevention tools used to indicate the approximate locations of pipelines along their routes to prevent "dig-ins" from occurring. They also advise the public of pipeline rights of way. Pipeline safety regulations require installation of markers because markers contribute to public awareness and damage prevention, which reduce the risk of loss of containment.

Figure 31 – Pipeline Marker

While the Transmission Pipeline Marker Program is already well established, implementation of the Distribution Pipeline Marker Program began in November 2024. In 2025, a total of 2,733 markers were installed at points where distribution mains crossed public roads or railroads in class 1 and 2 locations, achieving 66% completion of the overall planned scope.

Pipeline markers are typically found at various important points along the pipeline route including highway, railway, navigable waterway intersections, spans, angle points (bends), and other road crossings. These markers display the name of the operator and a telephone number where the operator can be reached in the event of an emergency. They are meant to be highly visible along the ROW and appear in different forms, as seen in the in the following figures.

Figure 32 – Pipeline Marker

Figure 33 – Pipeline Marker Sign

Figure 34 – Types of Pipeline Markers

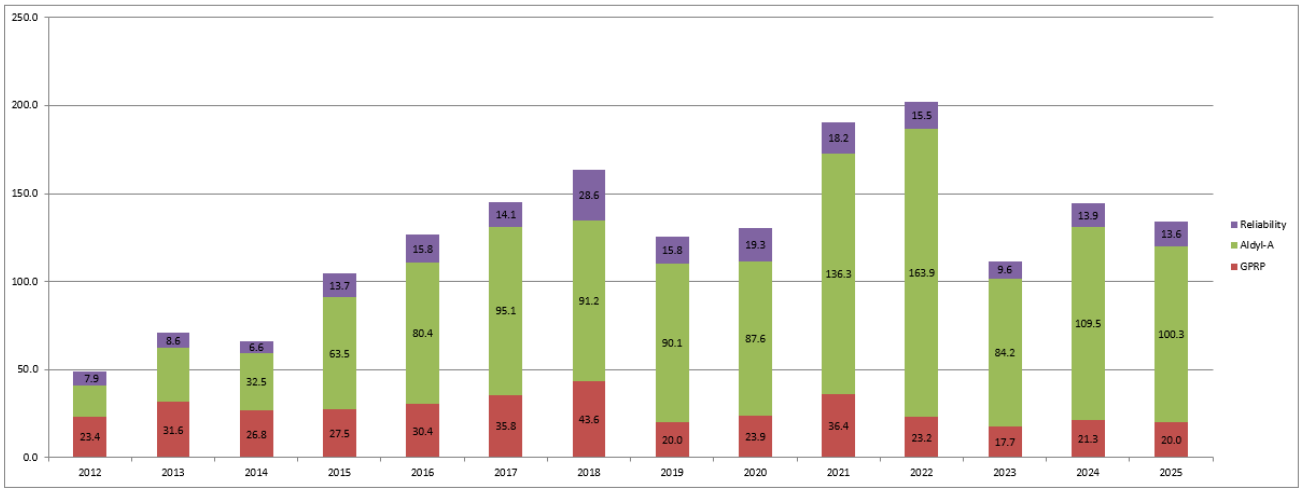
In the event of an emergency or natural disaster, markers may be the only indication to the public and emergency responders that natural gas pipelines are in the area.

c) Distribution Pipeline Replacement

PG&E has three pipeline replacement programs: The Gas Pipeline Replacement Program (GPRP), the Plastic Pipe Replacement Program, and the Reliability Main Replacement Program. The GPRP was established in 1985 with a focus on deactivation of cast iron and pre-1941 steel distribution pipe, enabling PG&E to deactivate all known cast iron pipe (over 830 miles of cast iron pipe). Today, the focus of the GPRP is on replacing or deactivating pre-1941 steel distribution pipe and post-1940 steel distribution pipe based on risk. The Plastic Pipe Replacement Program, established in 2012, mitigates risks associated with pre-1985 plastic materials through replacement or deactivation of pre-1985 plastic distribution pipe based on risk. Lastly, the Reliability Main Replacement Program focuses on the replacement of gas distribution pipe to improve safety and reliability for pipe assets not qualifying for replacement under either the GPRP or the Plastic Pipe Replacement Program.

An important element of providing safe gas distribution service is replacing aging or at-risk assets. PG&E uses relative risk to prioritize its pipeline replacement projects so that the sections of pipe with the highest risk are replaced first. The risk ranking for the GPRP is based on a methodology that considers pipe age, leak history, cathodic protection, coating, seismic activities, and population proximity. The risk ranking for the Plastic Pipeline Replacement Program is based on a methodology that considers leak history, pipe age, material type, ground temperature, diameter, operating pressure, and population proximity. PG&E identifies scope for the Reliability Main Replacement Program through local engineers working in conjunction with field employees and DIMP and prioritizes the work based on risk and compliance factors. The following figure demonstrates the Company's main replacement progress from 2012 to 2025.

Main Replacement 2012-2025 Actuals																	
Program			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	TOTAL (2012-2025)
14A	GPRP	Replacement of all cast iron and some steel main installed pre-1941	23.4	31.6	26.8	27.5	30.4	35.8	43.6	20.0	23.9	36.4	23.2	17.7	21.3	20.0	*381.6*
14D[a]	Aldyl-A	Replacement of Aldyl-A plastic and similar plastic installed pre-1985	17.6	30.7	32.5	63.5	80.4	95.1	91.2	90.1	87.6	136.3	163.9	84.2	109.5	100.3	*1,182.8*
50A[a]	Reliability	Replacement of gas facilities that have reliability concerns but do not qualify for replacement under the GPRP or Aldyl-A Plastic Replacement	7.9	8.6	6.6	13.7	15.8	14.1	28.6	15.8	19.3	18.2	15.5	9.6	13.9	13.6	*201.0*
		Total (miles replaced)	**48.9**	**70.9**	**66.0**	**104.7**	**126.6**	**145.0**	**163.4**	**125.8**	**130.7**	**190.8**	**202.5**	**111.5**	**144.7**	**133.9**	***1,765.4***



[a] Includes the Butte Rebuild replacement mileage performed in-concert with the Plastic Pipe Replacement Program (Capital, MAT 14D) and Reliability Main Replacement Program (Capital, MAT 50A).

Figure 35 – Main Replacement Progress 2012-2025 (in Miles)

With enough natural gas distribution pipe traversing underneath the ground to wrap around the equator of the earth over three times, a holistic approach that incorporates the condition of these assets and the risks to these assets must be considered. Implementing asset risk reduction strategies over a significant timeframe (half a century or more) is crucial. Absent prudent asset management, a time may come where short-term and reactive needs result in an asset failure rate that exceeds the capacity of the skilled and qualified workforce as well as exceeds a reasonable cost burden that customers are willing to pay over a short period of time to replace or repair the failed assets. This could result in an increase in the number of significant incidents because of loss of containment on these aging assets. With maturing policies and legislation, asset management seeks to evaluate alternatives to pipeline replacement, where feasible, through leveraging the Alternative Energy Program (AEP) and other electrification initiatives to incentivize cost-effective retrofitting of structures to alternative energy other than natural gas resulting in the possible retirement of gas distribution facilities as opposed to replacement.

d) Cross Bore Mitigation

A cross bore[23] is a gas main or service that has been installed unintentionally, using trenchless technology, through a wastewater or storm drain system. PG&E has an inspection program to identify and remediate gas cross-bores, and a public outreach program that provides safety information to PG&E customers, sewer districts, and public works agencies. In addition, PG&E has implemented a Gas Cross Bore Inspection Program that uses video camera inspections to verify that no damage has occurred to sewer lines when using trenchless construction methods on new construction projects.

Figure 36 – Cross Bore

The goal of PG&E's Cross Bore Inspection Program is to identify cross bores by completing inspections of potential conflict locations and repairing all occurrences as they are discovered. The Cross Bore Program is divided into two separate branches. The Legacy branch inspects older construction that predates the program's existence, while the Prevention branch performs inspections for current construction projects. Legacy completed approximately 6,901 inspections in 2025 and found 7 cross bores. Prevention completed approximately 36,162 inspections in 2025 and found 10 cross bores. Additionally, 11 Legacy cross bores were reported by Closed Circuit Television (CCTV) vendors and subsequently corrected through the Prevention program for a total of 21 cross bores cleared through the Prevention program.

In recent years, there has been an added focus to create cross bore awareness through the Cross Bore Public Awareness Campaign. The goal of the Cross Bore Public Awareness Campaign is to educate as many contractors, agencies, and members of the public as possible on the risk of cross bores to avoid the possibility of damage to a gas line during plumbing activities in sewer lines and to encourage investigation of the source of an issue via camera or other non-invasive means before more invasive measures are taken. Since 2024, the team has sent out approximately 7,400 mailers (see Figures 37 and 38) via USPS three times per year to plumbing companies throughout the territory to enhance awareness around cross-bore risk. Additionally, throughout the year the Cross Bore team partners with Damage Prevention to set up public awareness booths in front of stores such as Home Depot and Lowe's to inform those in the general public who might be renting sewer-clearing, or similar equipment, about safe practices. In 2025, Cross Bore provided training to over 900 Gas coworkers and contractors in more than 50 workshops to educate the cross bore standard to those who perform gas construction on behalf of PG&E. Regular education will continue to make sure that new coworkers are educated and existing coworkers are refreshed on the information in an effort to prevent future cross bores.

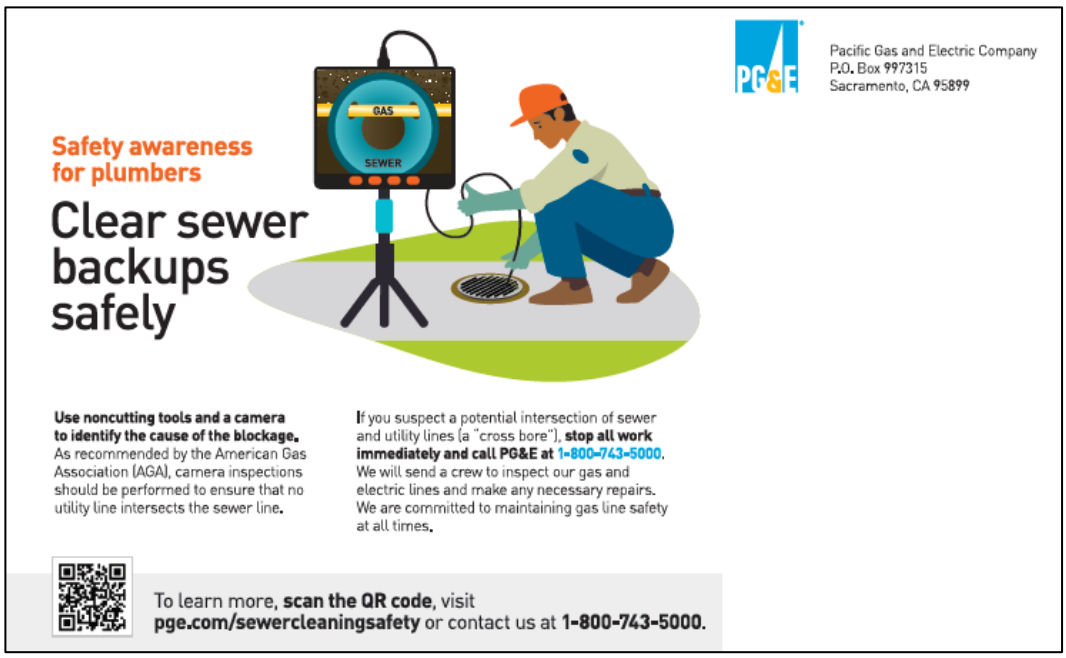


Figure 37 – Cross Bore Mailer (Front)

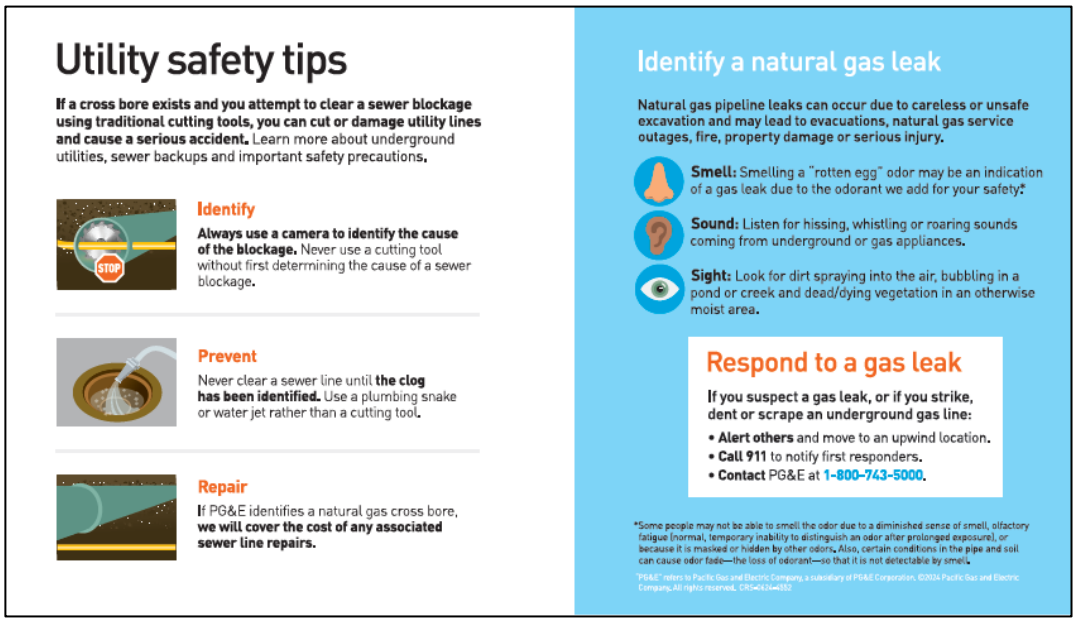


Figure 38 – Cross Bore Mailer (Back)

e) Strength Testing

Figure 39 – Strength Test in Progress

PG&E's transmission pipeline strength testing program is designed to allow PG&E to find pipeline defects that could subsequently cause a rupture or leak and then repair these defects or anomalies in the pipeline. Strength testing takes a pipeline out of service, clears it of gas, cleans it internally, then fills it (typically with water) to verify the pipeline's integrity and pressure capability. Testing is conducted in accordance with 49 CFR, Part 192, Subpart J testing and documentation requirements, or Minimum Test Pressures for Existing Pipelines in High Consequence Areas (HCAs) to meet the Seven Year Integrity Assessment Interval per the American Society of Mechanical Engineers (ASME) B31.8S-2004, Section 5, Table 3. This process establishes verified operating pressure capabilities for the pipeline. A secondary benefit of strength testing for PG&E is that the pipeline is typically upgraded to allow for navigation of cleaning tools (pigs), permitting PG&E to run In-Line Inspection tools at later dates [see *Section V.5.g In-Line Inspection* for more information]. Thus, strength testing is one tool PG&E uses to maintain the margin of safety for transmission pipelines and to reduce the likelihood of future loss of containment incidents that could pose a risk to public safety.

PG&E continues to strength test or replace untested transmission pipelines in compliance with Pub. Util. Code Section 958. In 2025, PG&E completed approximately 2.78 miles of strength testing (Table 22), of which 0.226 miles were re-tested for specific Integrity Management (IM) purposes. This work brings PG&E to a total of approximately 1,623 miles strength tested since 2011. The total miles of transmission pipe with test records are approximately 95 percent.[24] The pipeline miles strength tested in 2025 were prioritized based on a code compliance, a risk-informed mix of integrity management threats, and class location changes.

Table 22 – Transmission Pipeline Miles Strength Tested (Miles)

Strength Test	2011-2014	2015-2022	2023	2024	2025	Total
PSEP	674	N/A	N/A	N/A	N/A	674
Subsequent Testing	0	917	24	5	3	949
Total	**674**	**917**	**24**	**5**	**3**	**1,623**

PG&E will continue to use strength testing to re-assess pipeline segments with integrity management threats, including manufacturing-related defects subject to 49 CFR Part 192, Subpart O, and time dependent corrosion threats. Strength testing helps demonstrate that manufacturing and construction-related defects are stable by subjecting the covered segments to hydrostatic pressure testing in accordance with 49 CFR Part 192, Subpart J, and supports compliance with the MAOP reconfirmation requirements of 49 CFR § 192.624.

f) Vintage Pipe Replacement

PG&E considers vintage construction and fabrication threats interacting with land movement as a key risk facing transmission pipe assets. The Vintage Pipe Replacement program helps mitigate this risk. While age alone is not an indicator of high risk, the original installation year reflects the manufacturing and construction practices of that era. PG&E defines "vintage pipe" to include pipe manufactured, constructed, or fabricated using certain historic practices that are no longer in use today. Vintage construction features generally do not pose a threat unless "activated" by specific conditions such as axial loading or ground movement. These threats are best managed through replacement, thus eliminating vintage features. Historic fabrication and construction methods include mechanical/compression couplings and expansion joints, wrinkle bends, field miter bends and non-standard fittings (e.g., orange peel reducers, nonreinforced branch connections, sectioned fittings, homemade tees, bell-bell-chill rings, bell and spigot joints), oxy-acetylene welds, and excessive pups.

Figure 40 – Vintage Pipe Replaced in San Mateo

PG&E's Vintage Pipe Replacement program's vision is to address the risk of pipe segments containing vintage fabrication and construction threats that have a high likelihood of interacting with land movement within populated areas.[25] PG&E will continue to work on addressing vintage pipe by prioritizing high-risk projects to be completed first (Tier 1). Currently, there are approximately 1.01 miles of Tier 1 vintage pipe remaining in the system. In the 2027 General Rate Case, PG&E has proposed replacing 0.20 Tier 1 miles, which includes three Vintage pipe replacement projects.[26] As of 2025, the program has replaced or retired 99.04 miles of high-risk vintage fabrication and construction threats interacting with high likelihood of land movement.[27]

Priority	Required Action	Description
TIER 1	Prioritize for replacement. Continue to operate and monitor until mitigation is complete.	Segments with Vintage Construction Features located in consequence areas and/or areas with high pipeline rupture risk with known occupancy impacts with ground movement threats. • Vintage features, Consequence Area, ground movement threat. • Vintage features, IOC>0, TIMP Risk ≥ 90%, ground movement threat.
TIER 2	Prioritize for replacement project to be executed after completion of Tier 1 projects following annual Vintage Pipe run. Continue to operate and monitor until mitigation is complete.	Segments with larger pipe diameter (≥ 6"), above average pipeline rupture risk, potential occupancy impacts, but located outside of consequence areas, and have ground movement threats. • Vintage features, IOC>0, TIMP Risk ≥ 50% AND < 90%, Pipe diameter ≥ 6", ground movement threat.
TIER 3	Monitor for risk change using Geohazard and ILI data; continue to track in annual Vintage Pipe run. Continue to operate, monitor, and maintain in accordance with 49 CFR 192.	All other segments with vintage features that are not Tier 1 or Tier 2.

Figure 41 – Prioritization Tier Levels

PG&E continues to enhance risk methodology used to monitor and assess characteristics of vintage pipelines interacting with land movement by improving data quality and collection.

g) In-Line Inspection

PG&E's In-Line Inspection (ILI) Program uses technologically advanced inspection tools, often called "smart pigs," to assess the condition of transmission pipe so that action can be taken when issues are identified. Prior to running an ILI tool in a pipeline, the pipeline must be modified with installation of "launchers" and "receivers" to insert and remove the tool. These upgrades must also be performed to replace pipeline features that would obstruct the passage of the tool. After the pipeline is upgraded to accommodate an ILI tool, cleaning and inspection "runs" are conducted to collect data about the pipe. This data is analyzed to identify pipeline anomalies that must be remediated through the Direct Examination and Repair process. Integrity data obtained through ILI technology is also utilized as a cost-effective solution for reconfirming safe maximum pressure limits for existing assets compared to traditional methods, such as strength testing and asset

Figure 42 – Electro Magnetic Acoustic Transducer (EMAT) Tool After an Inspection on Line 400

In-Line Inspection is the MOST EFFECTIVE pipeline integrity assessment tool currently available to natural gas pipeline operators to assess the internal and external condition of transmission line pipe.

replacement. In this process, the anomaly is exposed, examined, and repaired as necessary. The information from Direct Examination and Repair is used to generate mitigation activities to improve the long-term safety and reliability of the pipeline.

As of 2025, approximately 60.55 percent of the PG&E gas transmission system is "piggable," a term used to indicate that the pipeline is eligible for the use of in-line inspection tools.[28] Last year, PG&E inspected a total of 549.36 miles, of which 113.14 miles were assessed with ILI for the first time. Much of PG&E's pipeline was installed decades before ILI was invented. As of 2025, about 34 percent of the PG&E gas transmission system cannot support the running of traditional ILI tools, because of design elements like low pressure (LP) and/or low flows, small diameter pipelines, tool availability, and short sections of pipeline or facility configurations, such as drips or blow downs.

Figure 43 – 24" x 30" Multi-Diameter Tool

In July and August 2025, ILI accomplished an important milestone with the re-inspection of the challenging peninsula pipeline, L-132, from mile points 0.00 to 31.93, using the low pressure, low flow 24" x 30" multi-diameter tool developed in partnership with ILI tool company, Rosen. This segment of pipeline passes through densely populated high consequence areas (HCA), and is on the pipeline that ruptured in 2010. This inspection culminated a 10-year journey in achieving optimum tool performance, speed profile and resulting data acquisition, with a 99.5% sensor coverage. The results identified 13 additional sites of external metal loss requiring remediation, currently underway or scheduled for 2026.

Figure 44 – 10" x 14" NT-ILI Tool Inspecting a 12" Pipeline

In 2025, the non-traditional (NT) ILI program accomplished another successful year of assessment, completing 16 inspections throughout the service territory. The growth and expansion of this program, including robot tools that are now capable of detecting more defects on the long seam, such as Selective Seam Weld

Corrosion (SSWC), is critical for meeting compliance in high consequence areas where traditional pigging or even direct assessment (DA) methods are not possible. To date, ILI has now surpassed 100 miles of NT assessment, primarily with robotic crawlers.

h) Corrosion Control

All of PG&E's metallic assets are susceptible to corrosion—a natural, time-dependent process where metal degrades (corrodes) due to its interaction with the environment. Gas transmission, storage, and distribution assets primarily composed of steel pipe carrying natural gas may experience degradation due to External Corrosion, Internal Corrosion, Stress Corrosion Cracking (SCC), SSWC, Microbial Influenced Corrosion (MIC), or Hydrogen Induced Cracking (HIC).

Figure 45 – PG&E Employee Performing Pipe-to-Soil Monitoring

External Corrosion is degradation of the pipe due to interaction of the steel with the atmosphere, soil (buried piping), and/or water (submerged piping). Internal Corrosion is degradation of the pipe due to interaction of the steel with unintended internal products such as water, solids, salts, etc. SCC is degradation of gas transmission pipe due to cracks induced by the combined influence of tensile stress[29] and a corrosive environment. SSWC is degradation of the pipe from localized corrosion along the bond line of low-frequency electric resistance welding (LR-ERW) and electric flash welding (EFW) piping. This can lead to the development of a wedge-shaped groove that is often filled with corrosion products. The material degradation associated with all forms of corrosion may reduce the integrity of steel assets and threaten PG&E's ability to safely and reliably transport natural gas. PG&E assesses the risk of External Corrosion, Internal Corrosion, and SCC independently because each requires a different form of mitigation.

Industry best practice corrosion control strategies try to address at least one of the four basic parts of the corrosion cell – Anode, Cathode, Metallic Path, Electrolyte. The primary corrosion mitigation strategy at PG&E is to apply coating systems to the exterior portion of the pipeline system to attempt to isolate the metallic pipeline system from the electrolyte (soils/atmosphere/water). In the areas where coating system damage or imperfections exist, PG&E attempts to mitigate the anode and cathode portion of the corrosion cell by applying CP and moving the metallic pipeline system to the cathode of the electrochemical cell. In cases where needed and system operations allow, PG&E will also replace the metallic pipeline system with plastic to remove the metallic path from the corrosion cell.

In 2025, PG&E continued ongoing revision support and completed full implementation of the PHMSA regulations (Mega Rule Part 2) that were published in 2023, prompting review and revision of standards, procedures, and training. This regulation is now fully incorporated into a PG&E corrosion control program that focuses on transmission pipeline restoration and mitigation timelines and expands requirements for AC and DC interference programs, internal corrosion monitoring and mitigation, as well as coating inspections of new pipelines. PG&E also participated in an Association for Material Protection and Performance (AMPP) committee that published a guidance document to assist all operators with interpretation and implementation of corrosion control methodologies to align with the 2023 PHMSA regulation.

Given the risk profile associated with corrosion, PG&E continues to strengthen its corrosion control approach. In 2025, this included hiring highly qualified corrosion experts from around the country, maintaining an industry-leading corrosion mechanic apprenticeship and line of progression, enhancing procedures where applicable, and incorporating systematic, risk-informed methodologies. These efforts resulted in more accurate data to support decision-making related to the identification and mitigation of corrosion risks, thereby improving the safety and reliability of PG&E's assets.

PG&E uses a remote monitoring system that allows for both scheduled and ad-hoc polling of CP equipment, with data automatically updated in the systems of record. This system allows PG&E to monitor the level of CP on its assets for conditions that may limit the ability to maintain adequate levels of CP on buried or submerged assets. Such conditions include contacted casings and electrical interference from electric transmission equipment, municipal rail systems, and other operators' corrosion control systems. For example, the gas corrosion team has partnered with electric distribution engineering to work on the dynamic stray current issue that has affected the greater San Francisco Bay Area. The team has rethought our longstanding internal standards and practices to begin retrofitting the BART station services with neutral isolation to attempt the reduce magnitude of stray DC currents. The first two pilot sites installed in 2025 showed promising results with an additional 30 sites scheduled for 2026. Overall, corrosion control at PG&E consists of the programs included in Table 23.

Table 23 – Corrosion Control Program	
Program	**Program Description**
Atmospheric Corrosion	Addresses deterioration of coating systems on assets designed for above ground use. Program includes field inspections and mitigation.
Casings	Identifies and remediates contacted cased crossings.
CP New, CP Replace	Designs, installs, and maintains CP systems to prevent corrosion. In addition, PG&E has implemented industry best practice CP criterion.
Close Interval Survey	Collects CP readings at approximate ten-foot intervals on transmission piping to verify levels of CP between established monitoring points.
Corrosion Investigations	Investigates the cause of corrosion control deficiencies and/or corrosion damage and recommends mitigating solutions.
Electrical Interference – AC	Evaluates and mitigates the threat of alternating current interference on gas piping systems.
Electrical Interference – DC	Evaluates and mitigates the threat of direct current interference on gas piping systems.
Enhanced CP Survey	Evaluates distribution piping CP area boundaries, monitoring locations, protection status, and updates documentation for proper operation of CP systems.
Internal Corrosion	Evaluates and mitigates the threat of Internal Corrosion in gas pipelines.
Routine Maintenance	Routine monitoring of corrosion control system effectiveness, to include rectifier inspections and maintenance; pipe-to-soil monitoring, casing-to-soil monitoring, and atmospheric corrosion inspections.
Test Stations	Installs or replaces test stations in areas along the piping system where CP monitoring is required.

PG&E continues to advance in its goal of building a best-in-class corrosion control program by incorporating industry corrosion control standards, peer operator experience, third-party evaluations, and corrosion research into its standards and procedures. In 2025, PG&E actively participated in corrosion research conducted by the Pipeline Research Council International (PRCI) and supported efforts to incorporate the results of such research into corrosion control regulations and standards through its participation in the Association for Material Protection and Performance (formerly National Association of Corrosion Engineers (NACE) International and the Society for Protective Pipe Coatings), the Interstate Natural Gas Association of America (INGAA), and the American Gas Association (AGA).

i) Earthquake Fault Crossings

The TIMP Fault Crossing Program addresses the specific threat of damage to a transmission pipeline from land movement strains caused by large earthquakes or seismic creep at known earthquake faults. Faults are discontinuities in the earth's surfaces that experience differential movement. Movements during earthquakes happen almost instantaneously and can range from inches to tens of feet.

The TIMP Fault Crossing Program is consistent with California law, which requires natural gas operators to prepare for and minimize damage to pipelines from earthquakes. PG&E performs system-wide studies to identify both anticipated geologic movement and pipeline mechanical properties to prioritize mitigations that will enhance the integrity of the pipe during a seismic event. Following each study, the mitigation work is then prioritized by considering the likelihood of failure, the probability that a seismic event will occur at the fault, and the consequences of failure, which includes the impact on the local population, PG&E system reliability, and the environment. Mitigation typically includes modified trench designs, trench adjustment, pipe replacement or realignment, or installation of automated isolation valves.

Figure 46 – L-301A Fault Crossing Pipe Replacement

For a given year, crossings mitigated are identified in a prior year's study. Although PG&E did not complete studies in 2025 due to a two-year completion cycle, seven studies are scheduled for completion in 2026. The studies include the Monte Vista Shannon Fault (11 crossings total), Little Lake Fault Zone (4 crossings total), Kern Front Fault & Premier Fault (4 crossings total), Hayward Fault (7 crossings total), San Andreas Fault (6 crossings total) Hat Creek (46 crossings total), and Central Calaveras (8 crossings total). At the end of 2025 there were 482 active fault crossings with 178 being fit for earthquake and another 20 fit for-earthquake at the 50th percentile, but not the 84th percentile. The 84th percentile is used where lines with higher incidence of consequence and pipe class cross more active faults. PG&E will continue to identify and evaluate new fault strands that could impact PG&E's transmission lines.

j) Leak Survey

Pipeline safety regulations require PG&E to conduct routine Leak Survey (LS) on its gas system to find gas leaks. The frequency of leak survey depends on the type of facility, operating pressure, and class location of pipe.

In 2025, PG&E surveyed over 1.4 million gas distribution pipeline services, over 13,000 gas transmission pipeline miles, and performed daily leak surveys on 103 wells in compliance with CalGEM's emergency gas storage regulations. In addition, PG&E completed quarterly CARB leak survey at the 13 Gas Transmission Compressor/Storage Well Facilities, consisting of 181,000 individual components. PG&E also performed daily leak survey of the three Storage Well facilities (Pleasant Creek, Los Medanos, and McDonald Island) as part of the COGR (CARB Oil and Gas Rule) for all 365 days of the calendar year.

PG&E conducts three-year leak surveys consistent with Best Practice 15 in the Leak Abatement OIR D.17-06-015. In 2025, PG&E updated the definition of a leak indication from five ppm (parts per million) to 200 ppm outside of five feet of a structure and/or ten feet wall to wall. The reason for the update was to be consistent with benchmarking and internal leak cancellation data. Going forward, PG&E will continue its expanded use of the Advanced Mobile Leak Detection technology for its gas distribution system targeting emissions as the main focus, which along with the leak survey cycle, will continue to support PG&E in its ability to: (1) find and fix more leaks, thereby eliminating more potential hazards to the public; and (2) reduce greenhouse gas (GHG) emissions.

In addition, in 2025, PG&E continued the Super Emitter survey across the entire distribution service territory in response to the Leak Abatement OIR, Best Practice 21. PG&E defines a Super Emitter leak as one that emits more than five standard cubic feet per hour of methane. As a result, in 2025, PG&E completed the Super Emitter survey on over 99 percent of its gas distribution services. The purpose of this survey is for Advanced Mobile Leak Detection to identify and measure the leak flow rates of Super Emitters as they are found. The data then informs PG&E of the prevalence of these leaks and emission reduction that can be gained by repairing them quickly.

In 2025, PG&E continued to maintain employee and public safety. One example was the use of drones with Open Path Spectrometry (OPS) leak detection units to survey submerged transmission pipelines and spans hung over waterways. This prevents some temporary road closures and reduces the number of surveys completed in navigable waterways with boats.

PG&E's leak survey and Atmospheric Corrosion (AC) inspection Can't Get In (CGI) process continues to be successful, seeing the backlog of open inspection CGIs lessen year over year down to the lowest levels since the program began in 2018. 2025 began with a backlog of 591 AC CGIs and 876 Leak Survey CGIs and ended with 321 and 615, respectively. During 2025, 48,932 AC CGIs and 38,708 LS CGIs were created. Overall, 99.5% of CGIs created in 2025 were completed in year.

In 2025, PG&E continued to utilize the process designed in previous years and implemented several process improvement initiatives that increased the success rate of completing mandatory inspections. The process includes letters, text messages, emails, automated Interactive Voice Response phone calls, and personalized outbound calls from a team of Service Representatives attempting to gain access to PG&E facilities. The text messages and emails include custom portal links to a PG&E site that allows customers to schedule their appointments from their computers or smartphones. Concurrently with the attempts to schedule appointments, Gas Compliance Representatives attempt to complete inspections via canvassing. PG&E continues to utilize electric service interruptions to support compliance with state and federal regulations as well as reduce the risk of gas leaks to keep our public safe if customers do not provide access after previous unsuccessful attempts. Enhanced appointment tracking

and existing reports were improved, resulting in a higher level of visibility to the backlog of work. Improvement examples include updates to customer notifications for appointments and to the electric service interruption timeline and process. Summaries of PG&E's 2025 Leak Survey cycles for its distribution and transmission pipeline systems are shown in Table 24.

Table 24 – Leak Survey Cycles

Facility Types[(a)]	Description	Survey Frequency
Distribution	Business districts and public assemblies	Annually
	Buried metallic facilities not under CP and not covered by an annual requirement	3 Years
	All copper facilities	3 Years
	Balance of underground distribution facilities	5 Years
Transmission	Department of Transportation (DOT) transmission all odorized transmission (including non-HCA pipe within a Class III and Class IV location)	Semi-Annually
Un-Odorized DOT Transmission and Un-Odorized DOT Gathering	Class I, Class II, and Class III	Semi-Annually
	Class IV	Quarterly
Gathering (odorized)	Class I, Class II, Class III, and Class IV	Annually
Transmission Stations	Class I, Class II, and Class III	Semi-Annually
Electric Substations	Any existing facilities within 150 feet of the structure	Annually (PG&E Best Practice)

(a) Utility Procedure TD-4125P-10, "Identifying Gas Transmission Assets."

k) Leak Repair

Pipeline safety regulations and California state code require PG&E to repair certain leaks. In 2025, PG&E's trained and operator-qualified personnel graded leaks based on the severity and location of the leaks, the risk the leaks present to persons or property, and the likelihood that the leaks will become more serious within a specified amount of time.

Count of Leaks Repaired

Year	Above Ground	Below Ground	Grand Total
2016	18,204	9,274	27,478
2017	20,195	8,707	28,902
2018	28,598	12,847	41,445
2019	26,949	10,338	37,287
2020	12,870	11,823	24,693
2021	8,706	12,109	20,815
2022	6,446	11,242	17,688
2023	3,990	9,394	13,384
2024	3,413	8,678	12,091
2025	3,379	8,626	12,005
Total	132,750	103,038	235,788

Figure 47 – Count of Leaks Repaired

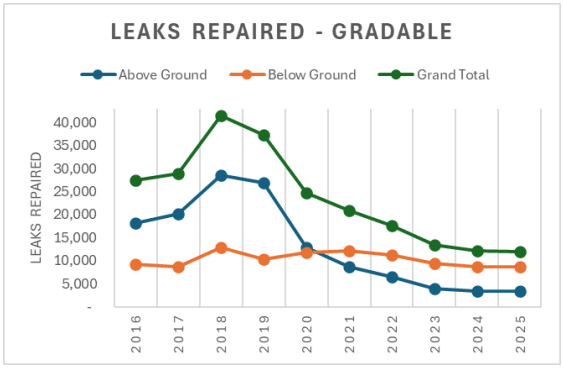


Figure 48 – Leaks Repaired - Gradable

As seen in Figures 47 and Figure 48, the number of leaks repaired since 2016 has decreased throughout the years. The volume decrease can be attributed, in part, to initiatives to repair Grade 2 leaks within 150 days and to repair a minimum of 1,000 below-ground Grade 3 distribution leaks annually. PG&E's leak grading practices for Grade 3 leaks exceed industry guidance, as set forth in GO 112-F. In addition

to rechecking annually as required, PG&E repairs above-ground Grade 3 leaks on its distribution system within 36 months of discovery. Last year, PG&E repaired 1,060 below-ground Grade 3 distribution leaks.

In 2025, PG&E used its continuous improvement approach to more efficiently bundle and schedule leak repairs. Identifying all the work required in an area at one time provides the opportunity to bundle work locations and maximize use of resources. Last year, PG&E repaired 12,005 gradable leaks on the gas distribution and transmission system.

Figure 49 – PG&E's Maintenance & Construction Crew at Work

PG&E also focused on improving Leak Repair effectiveness and efficiency by maintaining a level-loading approach in 2025, managing the average days open for gradable leaks rather than the inventory of Grade 2 leaks at the end of the year. PG&E set an internal target for average age of open Grade 2 leaks of less than 150 days and exceeded that goal with the average days open of 104 days for 2025. In addition, PG&E has launched a Value Stream Mapping (VSM) initiative to evaluate and identify potential enhancements within the Distribution Leak Repair process. The primary objective of this project is to implement system and process improvements aimed at eliminating bottlenecks identified through VSM analysis. The project is scheduled for completion in 2026.

PG&E continues to review and improve its standards, procedures, field processes, and equipment to further reduce both the public safety risk and the emissions from gas leaks.

l) Overpressure Elimination Initiative

PG&E is required to design and maintain its facilities per the Code of Federal Regulations Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards. These regulations are enforced to prevent a pipeline from operating above its MAOP safety design limits set forth in 49 CFR 192.201. Exceedance of these limits is defined as an Over-Pressure (OP) event. Pipelines operating in this abnormal operating condition (AOC) present an operational risk to the safety of the public, employees, and contractors working on the facilities and have the potential to overstress a pipeline, which may lead to a loss of containment. A failure of this magnitude poses significant safety and operational impacts to any gas system, as seen from the Merrimack Valley OP event.[30] PG&E tracks all OP events for learning purposes, including exceedances above MAOP (small OP events) and exceedances beyond the 10 percent regulatory allowance (large OP events).

Based on historical analysis of overpressure events, the Facility Integrity Management Program (FIMP) identified human performance (HU) and equipment failure (EQ) as the two most common causes

of OP events. Non-standardized station design and maintenance operations, inadequate processes, and lack of risk awareness were found to be the main contributing factors leading to OP events caused by HU. Initial HU OP reduction efforts targeted these factors by standardizing station designs, improving maintenance and construction operations, improving processes for lock-out / tag-out; and distributing information around associated OP risk factors through training and communication initiatives. OP events due to equipment failure are attributed to equipment installed at pressure regulating / limiting facilities. Pilot-operated regulation equipment is particularly vulnerable to failure by: (1) gas quality issues, such as pipeline and construction debris, sulfur, and liquids, which can inhibit correct operation, and (2) the design and functionality, which depend on externally connected control lines. A loss to the control lines for each regulating device will cause both the regulator and the primary overpressure protection (OPP) to fail in an open position. This type of failure is referred to as a common failure mode.

Beginning in 2018, PG&E began mitigating the common failure mode at pilot-operated T&D facilities. The primary solution to mitigate the common mode of failure was the installation of a slam shut as secondary overpressure protection. This device is integrated onto existing regulation equipment and protects the downstream system by isolating it from an upstream system operating at higher pressures when activated. In 2020, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act was published, requiring the common failure modes on distribution pressure limiting facilities to be mitigated. In 2025, PG&E installed slams shuts at approximately 100 of its various types of distribution and transmission facilities. This brings the total to 57 percent of facilities with common failure modes mitigated by slam shut installation since 2018.

Additional methods of OP mitigation were adopted by PG&E at low pressure (LP) distribution facilities with the 2018 publication of the Safety Recommendation Report on the Merrimack Valley OP in Massachusetts by the National Transportation Safety Board (NTSB). These include the creation of a polygon in the GIS to establish a field personnel standby requirement when construction is within 100 feet of a low-pressure station and an LP sense line relocation program created to protect against construction or third-party damages. The latter requires buried sense lines to be moved into the regulator or monitor vaults, which is consistent with industry standards.

In 2019, the first annual version of the Long-Term Overpressure Elimination Roadmap was published. This comprehensive document describes in detail past, current, and proposed future activities related to the OP elimination initiatives. On-going work continues to explore additional controls and mitigations for OP prevention from equipment-related causes, construction activities, third-party damage, and human performance issues during maintenance. The FIMP Team remains dedicated to sharing the pathway to success of the Long-Term Overpressure Elimination program in the annual publication of the Gas Safety Plan.

In 2025, PG&E recorded a total of 23 OP events, seven of which were large OP events, remaining below the long-term moving average of eight OP events per year since tracking began in 2011 (Figure 50). Key points of emphasis that continue driving down the number of overpressure events going forward include: (1) the continuation of the strategy of installing secondary overpressure protection devices on pilot-operated regulation equipment; (2) the continued emphasis on human performance development and training; (3) eliminating deviations from the standardized station design during installation; and (4) continuation of additional rigor around the clearance development and execution process. PG&E reviews operations and looks for opportunities to perform work to further limit potential OP events. Each activity builds on the goal of eliminating large OP events, thereby contributing to system safety. PG&E did not receive funding for any of the OPE mitigation programs in the 2023 GRC Final Decision, D.23-11-069, and PG&E anticipates that the rate of progress for many of these programs may slow significantly in the upcoming years.

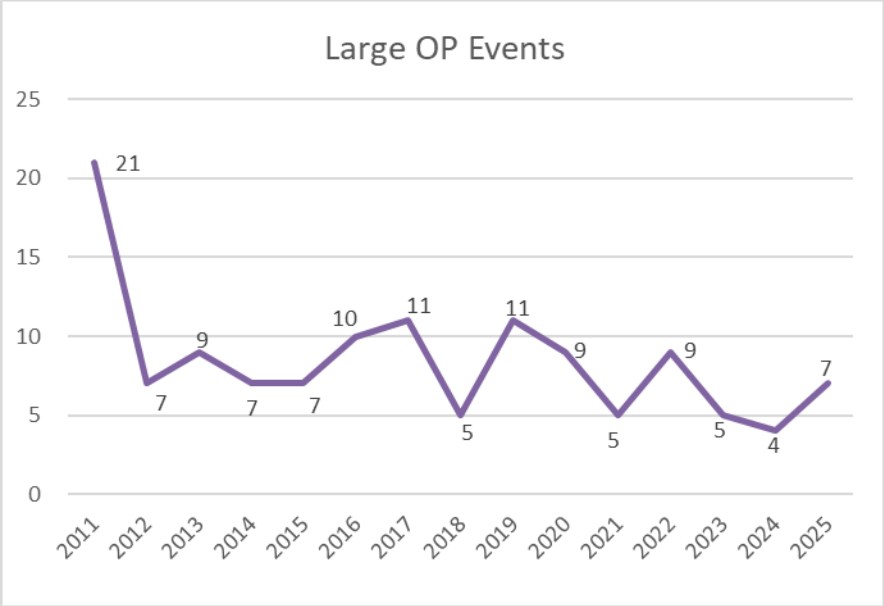


Figure 50 – Large Overpressure Events (2011-2025)

m) Community Pipeline Safety Initiative

As part of PG&E's efforts to enhance safety and reliability, PG&E launched the Community Pipeline Safety Initiative (CPSI). Through this program, PG&E reviewed the area above the natural gas transmission pipeline system for structures, trees and brush located too close to the pipeline for safety. When structures and trees are located too close, they can delay critical access in an emergency and potentially cause damage to the pipe.

PG&E has addressed more than 99 percent of items identified as a safety concern through this program, clearing approximately two miles of vegetation and removing 19 trees in 2025. The remaining vegetation work is located in the City of Palo Alto and Santa Cruz County. PG&E is actively engaged with

these jurisdictions and private property owners to complete all remaining work and conclude the program.

OVERALL PROGRAM METRICS (2013-2026)							
STRUCTURE MILES | 100% ADDRESSED				**VEGETATION MILES** | >99% ADDRESSED			
YEAR	ACT + FCST	PERCENT	COMPLETE	YEAR	ACT + FCST	PERCENT	COMPLETE
2013	5.00	1%	5.00	2013	115.00	7%	115.00
2014	110.00	32%	110.00	2014	146.00	17%	146.00
2015	93.00	58%	93.00	2015	380.00	41%	380.00
2016	114.00	89%	114.00	2016	540.00	76%	540.00
2017	30.00	98%	30.00	2017	258.00	93%	258.00
2018	7.60	99%	7.60	2018	86.60	98%	86.60
2019	0.25	99%	0.25	2019	18.03	99%	18.03
2020	0.00	99%	0.00	2020	0.26	99%	0.26
2021	0.0191	99%	0.0191	2021	0.91	99%	0.91
2022	0.00	99%	0.00	2022	1.81	99%	1.81
2023	0.066	99%	0.066	2023	0.00	99%	0.00
2024	0.028	100%	0.028	2024	3.24	99%	3.24
2025	0	100%	0	2025	5.63	99%	1.96
2026	**0**	**100%**	**0**	**2026**	**5.79**	**100%**	**0**
TOTAL	359.96	-	359.96	TOTAL	1,561.27	-	1,551.81

Figure 51 – CPSI Metrics - Structure and Vegetation Miles Addressed (2013-2026)

n) Gas Transmission Vegetation Management

In an effort to maintain the gas transmission right-of-way (ROW) safety clearances established through CPSI, PG&E's Gas Transmission Vegetation Management (GTVM) program regularly monitors the area above the pipeline for items that could pose a safety concern, such as new structures or newly planted vegetation. As part of these routine inspections, PG&E also reviews trees left in place during CPSI, for changes to site conditions, soil stability, tree health, and more, to make sure they have not developed into a safety concern.

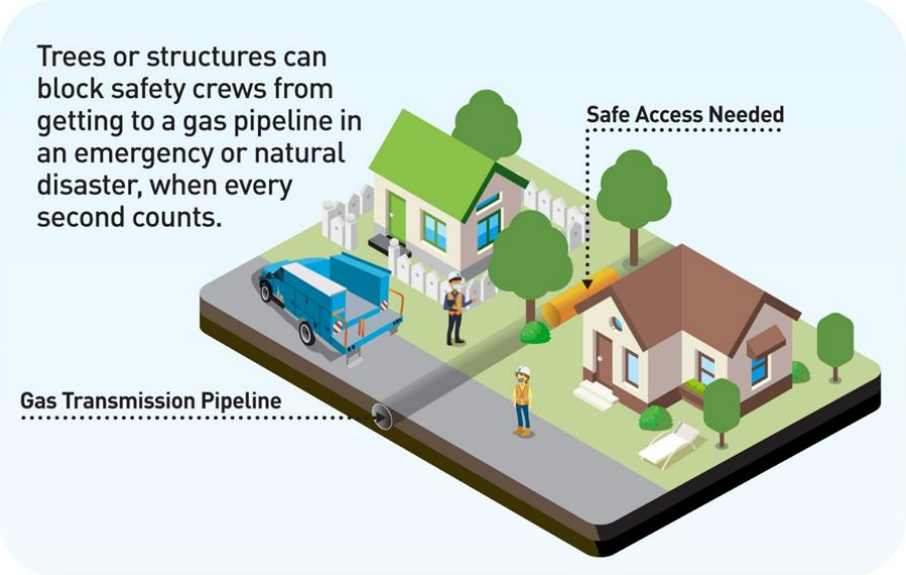


Figure 52 – GTVM ROW - Example of a Trees/Brush Inspection Site

To align gas vegetation management efforts with the latest industry standards and best practices, PG&E updated technical documents, including the standard, TD-4490S and procedure TD-4490P-03. These guidance documents have implemented revisions to the GTVM program and based on these updates, PG&E transitioned from a three-year inspection cycle to a seven-year inspection cycle and evolved the criteria by which individual trees are determined to be a safety concern. The program revisions were successfully implemented before the effective dates of the new guidance documents in Q3 of 2025.

As part of the GTVM ROW inspections, PG&E also reviews the areas near gas transmission pipelines for pipeline markers and indicators that may be damaged, missing or obscured by vegetation. Any vegetation obscured markers or indicators are addressed as part of the revised program.

In addition to addressing trees and brush located too close to the pipeline, PG&E supports break-in vegetation management requests from other PG&E Gas teams for efficiency. This helps provide visibility to the right-of-way and clear access so coworkers can safely perform work.

Keeping the area above the pipeline clear is a shared responsibility; it cannot be done alone. PG&E works with property owners to remove or relocate any vegetation identified as a safety concern. PG&E also works to relocate structures if needed, though this work is performed at the property owner's expense. Additionally, steps are taken to educate customers on the importance of keeping the area above the pipeline safe through resources such as email communications, fact sheets, community meetings, presentations, social media, and more. PG&E's educational outreach helps to spread awareness about safe planting near utility infrastructure which helps reduce the number to new trees from being planted too close to transmission pipelines.

6. Mitigating the Risk of Loss of Supply

The risk of loss of gas supply poses significant public health and safety risks. Customers depend on their gas service for various energy needs including space heating, water heating, and cooking. In very cold weather, loss of space heating can be life-threatening and increases the risk for customers to use unsafe heating alternatives.[31] Loss of gas service can also lead to extinguished gas pilots and the subsequent potential for non-combusted gas to enter affected buildings. In addition, electric reliability is dependent on gas reliability – as electric demands increase, gas-fired electric generation increases as well. In some scenarios, insufficient local pipeline capacity could result in loss of gas service to electric generation customers, which also introduces health and safety concerns. PG&E mitigates these risks by designing and operating its gas system to maintain adequate system capacity to supply forecasted demand.

In 2025, PG&E transported and delivered about 880 billion cubic feet of gas, a 4.7 percent decrease from the previous year.[32] To meet this demand, PG&E works year-round to assure system reliability through its management of system pressure, capacity, monitoring, and controls. The following sections discuss PG&E's programs designed to mitigate the risk of losing gas supply.

a) System Capacity Design Criteria

PG&E's gas systems are designed to meet all expected core demands (residential and small commercial customers) on Abnormal Peak Day, or APD, a design temperature that is the coldest temperature that may be exceeded once every 90 years. On APD, noncore demand (such as large commercial or industrial customers) is assumed to be fully curtailed. PG&E's gas systems are also designed to meet all expected core and noncore demand at the coldest temperature that may be exceeded once every two years, on average (referred to as a Cold Winter Day, or CWD).

In addition to noncore curtailments, temporary manual operations can be implemented to increase available capacity on the gas system or shift flow to alleviate system constraints [see *Section V.2.c Transmission Pipe* for Strategic Objective on meeting system capacity]. These operations are assumed to be in place when designing the system for capacity.

Table 25 – PG&E Gas System Capacity Design Criteria

Design Temperature Average Recurrence Interval	Design Condition
Once in 90 years, APD	Meet all expected core customer demand, with noncore demand assumed fully curtailed.
Once in 2 years, CWD	Meet all expected core and noncore customer demand.

PG&E develops its capacity plans with the use of hydraulic simulation software to model its gas system. These models calculate expected pressures and flows throughout the system based on historical SmartMeter customer demand data trends. An annual model maintenance process reinforces that hydraulic models accurately reflect the physical and operational characteristics of the gas system. The

process includes calibration and documentation components. Hydraulic models are accompanied by numerous analytical tools, processes, standards, internal and external data, and training and development so that personnel are properly equipped to implement the necessary measures for mitigating the risk of loss of gas supply.

b) Inventory Management

Inventory management is a critical service provided by Gas T&D to deliver safe and reliable gas to its customers. PG&E's pipeline inventory constantly changes due to the dynamic inflows and outflows of the system (Figure 54), so it is critical to keep inventory in balance. If inventory is too high, maximum pressures in the pipeline are approached and compressors can shut down. If inventory is too low, there is inadequate pressure to serve PG&E's customers.

Gas T&D utilizes several operational tools to maintain balance in pipeline system inventory. PG&E's Gas Storage provides withdrawal and injection services for Pipeline Balancing and Reserve Capacity. Operational Flow Orders and Emergency Flow Orders are gas marketing tools to financially incentivize customers to help keep the system in balance. In 2025, there were a total of 69 Operational Flow Orders (59 for high inventory, and 10 for low inventory) called to mitigate forecasted low and high inventory issues.[33]

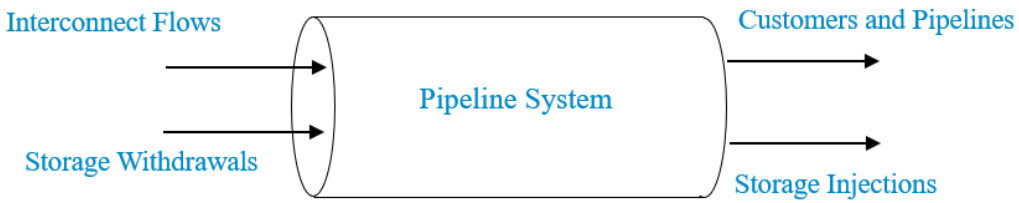


Figure 53 – Example of Pipeline System Inflows and Outflows

c) Winter Operations

In addition to designing and building its gas system to meet forecasted customer demand, PG&E prepares a detailed operation and curtailment plan prior to each winter. These plans outline the planned response to forecast cold weather conditions so that the system maintains reliable gas service and follows capacity design standards. PG&E continuously monitors pressures throughout the pipeline and responds to any SCADA alarms that activate if system pressures fall to a level that is lower than what is expected [see *Section V.7.a Gas System Operations and Control* for more information]. Increased Transmission and Distribution SCADA monitoring points in recent years provide much higher visibility of the gas systems than in the past. Winter operating plans and long-term capacity plans are adjusted, as needed, based on actual system performance.

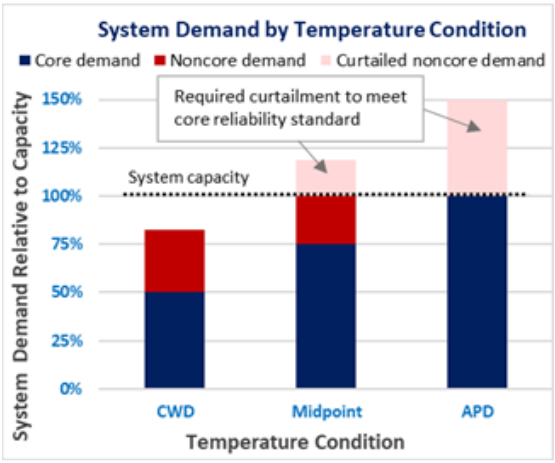


Figure 54 – Conceptual Representation of a Non-Core Curtailment Plan

d) Operations for Facilitating Safety Work

In some cases, the measures necessary to mitigate risk require temporarily changing the configuration of the gas system. For example, conducting a strength test requires taking a pipeline out of service. Another example is if pipeline anomalies are discovered through in-line inspection, the operating pressure of a system may need to be reduced until the anomalies can be further examined and repaired.

PG&E attempts to schedule safety work such that adequate supply to customers is maintained. However, if adequate supply is unavailable, other techniques such as portable LNG, CNG, or compression are utilized. If necessary, planned service outages that are coordinated with customers may need to occur. Any operations necessary to maintain sufficient capacity in the system are documented in a clearance [see *Section V.7.b Clearance Operations* for more information]. Clearances can also include SCADA alarm adjustments and pressure gauge monitoring requirements to strengthen safe operation of the gas system.

Guidelines are in place for traditional in-line inspections that require the consideration of contingency plans to mitigate the risk of supply interruptions in the low probability event that an inspection tool becomes stuck in the line and restricts supply to the downstream system. If the risk cannot be fully mitigated, an emergency curtailment plan is developed and undergoes leadership approval in advance of the inspection.

7. MITIGATING THE RISK OF INADEQUATE RESPONSE AND RECOVERY

In addition to the programs that PG&E has in place to mitigate the risk of loss of containment and the risk of loss of supply, PG&E is prepared to respond to incidents. PG&E's policies and procedures provide system controls for both equipment and personnel to limit damage from accidents, explosions, fires, and dangerous conditions.

It is PG&E's policy to:

- Plan for natural and human-caused emergencies such as fires, floods, storms, earthquakes, cyber disruptions, and terrorist incidents;
- Respond rapidly and effectively, consistent with the National Incident Management System and State Emergency Management System principles, including the use of the Incident Command System, to protect the public and to restore essential utility service following such emergencies;
- Help alleviate emergency related hardships; and
- Assist communities to return to normal activity.

All PG&E emergency planning and response activities are governed by the following priorities:

- Protect the health and welfare of the public, PG&E responders, and others;
- Protect the property of the public, PG&E, and others;
- Restore gas and electric service and power generation;
- Restore critical business functions and move towards business as usual; and,
- Inform customers, governmental agencies and representatives, the news media, and other constituencies.

PG&E uses the structure of the Incident Command System to complete key steps in responding to incidents. The key incident response objectives in Table 26 represent a typical process flow through the cycle of an incident.

Table 26 – Key Incident Response Objectives

Objective	Description
Pre-Incident Readiness	Proactive actions taken to prepare for a potential incident.
Make Safe and 9-1-1 Standby	Make area safe for public, employees, and responders.
Establish Command	Gather information about emergency, assess the situation in coordination with law enforcement and fire agencies, PG&E GCC, assign resources, and establish the Incident Command Post (ICP)
Notify	Communicate to/notify the appropriate PG&E personnel, regulatory agencies, public agencies, city, and county emergency operations, GCC, customers and media.
Assess Damage	Identify potential public and PG&E infrastructure threats or at risk and determine need for isolation strategies.
Restore	Prioritize restoration efforts and restore gas service.
Demobilization	Deactivate ICP and/or Emergency Centers and return to business as usual.

The following sections discuss programs in place to mitigate threats to enable PG&E to respond in a timely manner.

a) Gas System Operations and Control

PG&E's Gas Control Center (GCC) remotely monitors and controls the pipeline facility 24 hours a day, 365 days per year, for safe and reliable operations. Effective emergency response stems from strong situational awareness – the ability to identify, process, and understand critical information. The SCADA system is a key source of data, providing safety-related alarms that enable GCC staff to respond promptly and appropriately to normal, abnormal, and emergency conditions that may pose a safety risk to the public and PG&E employees. Enhanced SCADA visibility aims to further strengthen GCC's real-time awareness of pipeline conditions.

Figure 55 – PG&E's Gas Control Center Features a 90 Foot-Long Video Wall with Current Operational Information to Augment the Gas SCADA System

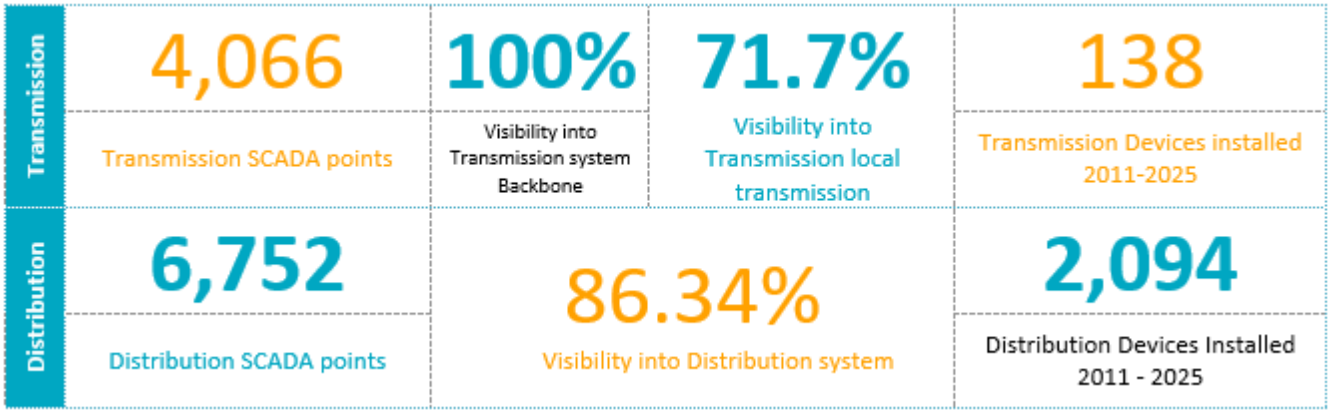


Figure 56 – PG&E's Progress in Enhancing System Visibility Through SCADA

Once GCC is aware of an event, it functions as a hub for operational collaboration to oversee a prompt and effective response. Response and recovery capabilities are enhanced by co-locating transmission and distribution control centers with core support teams. Robust communication protocols are in place so that field personnel can be reached at any time, while multiple connectivity solutions

enable real-time notifications and collaboration across sites. Sharing the same environment improves visibility, team cohesion, and facilitates faster communication and information exchange. This integrated approach to visibility and control supports PG&E's Gas Safety Excellence vision.

b) Clearance Operations

The Gas Clearances and Lock Out Tag Out (LOTO) program is required by CalOSHA and supports safe work, protects equipment, maintains configuration control, and allows PG&E to advance public safety. A Gas clearance document sets forth the sequence of operations that must be followed so that equipment clearing is done in a methodical, well planned, and controlled way. Clearances are established for all T&D planned and unplanned work that impacts gas flows, pressures, remote monitoring and control, or gas system quality and control.

The Clearance and LOTO Program is one of the most important processes within Gas and is also a PG&E Key to Life. When followed, the Clearance and LOTO process creates an essential control to isolate people from high energy and thereby prevent serious injuries and fatalities.

In 2025, process improvements were implemented to place heightened focus on risk awareness and readiness for upcoming clearance work at the Clearance Supervisor, Superintendent, and Leadership levels. For instance, procedural guidance was issued on how to identify and prepare for complex and high risk clearances, weekly cross-functional reviews were held to discuss upcoming complex and high risk clearances where work can be stopped if not ready, Director-level approval was required of new

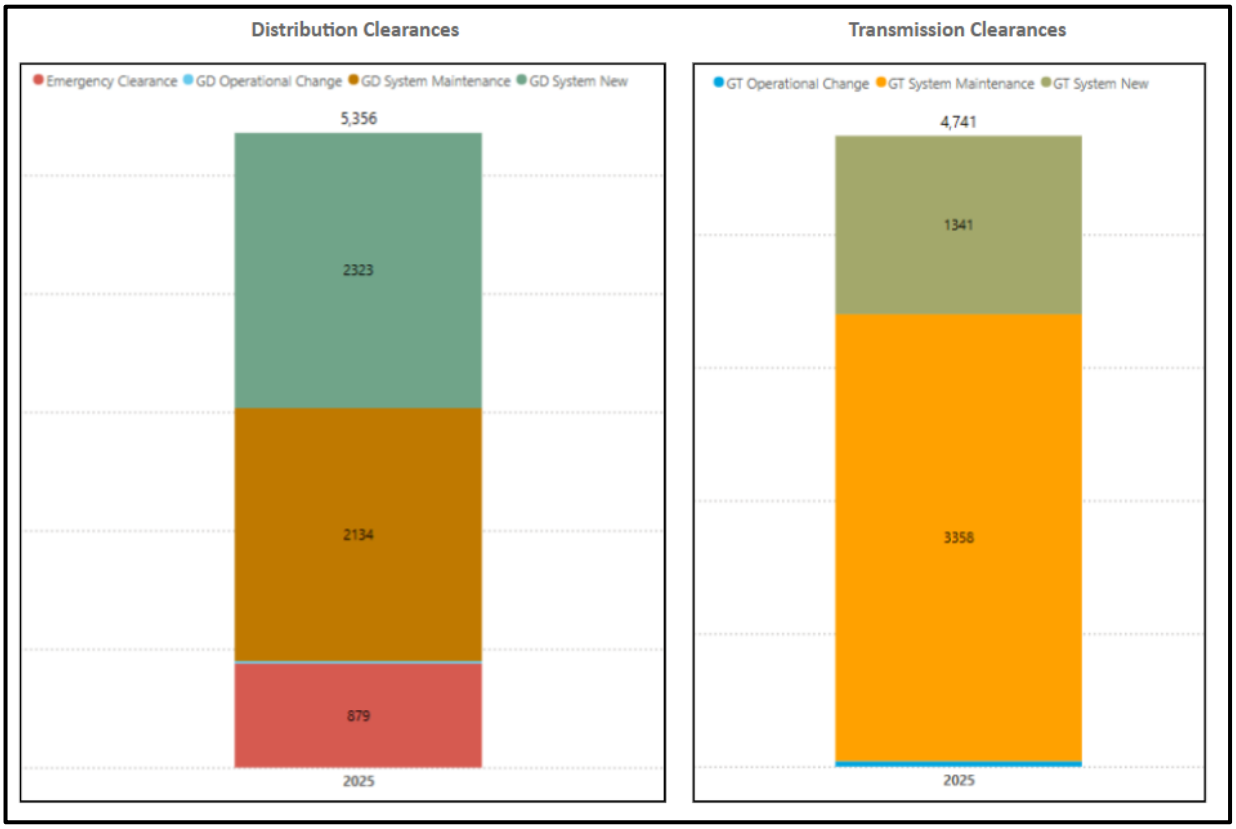


Figure 57 – 2025 Gas Clearance Volume by Type

clearances being requested with less than two-week notice, and new performance indicators were created to monitor the quality and timeliness of clearances. As a result, positive improvements were seen in the planning, preparation, and execution phases of clearance work. One example is the overall break-in clearance rate for 2025, which was a 10-year low and the lowest number ever achieved. There were no injuries or significant events during any of the 300 state-wide complex and high-risk clearances executed by the Transmission Pipeline Clearance Operations (TPCO) Department. And the program ended the 2025 calendar year below the annual target for clearance revisions after approval.

The Kettleman Ignition Event Root Cause Corrective Actions continued to be a high priority for the Gas Organization throughout 2025. Improvements in purging practices, guidance, and training, quality assessments, and advanced Clearance Supervisor training are all critical areas undergoing change and improvement that will help foster consistently safe outcomes for complex clearance work. In 2026, benchmarking, internal and external to PG&E, will continue to be the key focus for the Clearance Program alongside the remaining Corrective Actions. These and other program actions are in place to continuously improve and mature PG&Es Gas Clearance and LOTO Program in 2026.

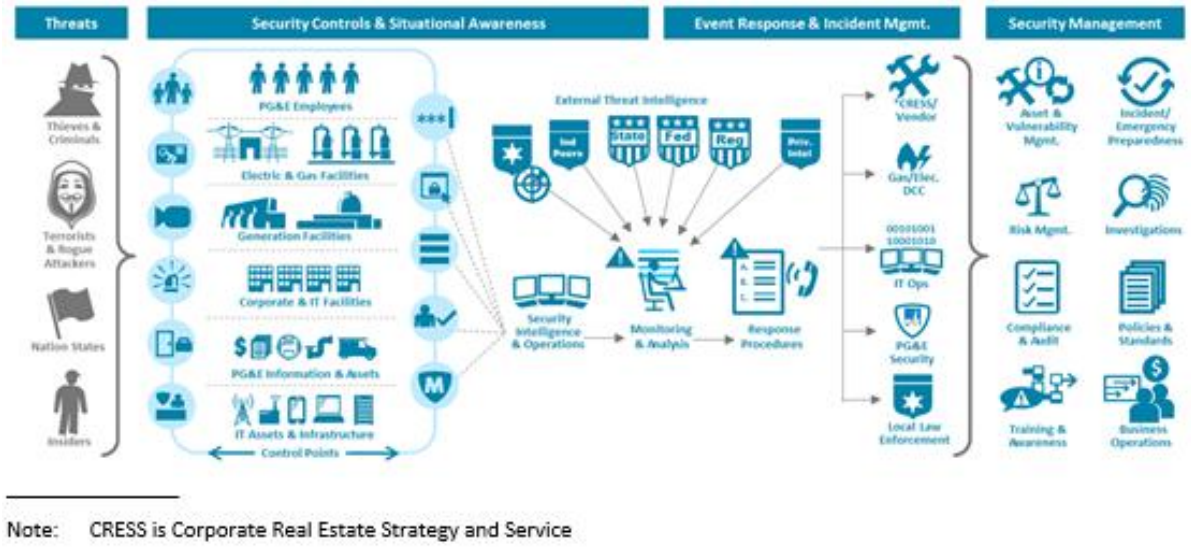
c) SECURITY

PG&E's commitment to security directly contributes to the mission to deliver safe, reliable, affordable and clean energy. PG&E's Security Program, which includes both cyber and physical security, effectively manages security risks and proactively adapts to evolving threats and changing business needs. The Security program is based on industry framework and best practices and is designed to enable risk-informed decision-making necessary to support PG&E's mission.

Security takes a multi-layered approach when implementing our strategies to protect PG&E's customers, assets, people, facilities and data from the ever-changing security threat landscape.

The Security program's strategy includes the following:

1. Identifying threats, risks, and defining mitigating strategies for them.
2. Building, deploying, and operating effective security technologies and processes.
3. Proactively monitoring, testing, and responding to security threats.
4. Collaborating with public, private, local, state and federal entities to proactively drive improvements to regulations, policies, standards and best practices.



Note: CRESS is Corporate Real Estate Strategy and Service

Figure 58 – PG&E Unified Cyber/Physical Security Program Effectively Manages Risk

Threat Intelligence: PG&E's Converged Threat Intelligence team tracks emerging and evolving activity that may pose a threat to the well-being of PG&E's employees, customers, and business enterprise. The team provides a centralized, converged approach to correlate and analyze information from varied internal and external sources, both physical and cyber, into a coordinated view and response. This approach aims to deliver a timely and accurate characterization of any incidents and thereby enable a coordinated response. Identified threats are mitigated at the appropriate levels.

The Security Intelligence & Operations Center's Threat Intelligence team tracks evolving cybersecurity and insider threats. Trends include a growing prevalence and sophistication of ransomware, destructive malware, and the growth of file-less malware on endpoints. Additionally, supply chain and critical infrastructure threats continue to grow in sophistication and frequency. The team also tracks threats from coworkers, ranging from inadvertent behaviors contrary to PG&E policy, to behaviors against PG&E core values, to criminal behaviors. Threat Intelligence also tracks scam activity targeting PG&E's hometown customers that may prevent them from receiving the best possible gas and electric service.

The Converged Threat Intelligence Team produced six Gas functional area specific executive summaries in 2025 while the Security Intelligence & Operations Center's Threat Intelligence team produced eight intelligence briefings to the GCC Operations Team, the GCC Executive Leadership Team, and the Gas Cybersecurity Technical Committee.

Security Awareness & Training: PG&E's Security Awareness and Training Program is an enterprise security strategy focused on maintaining and strengthening the security culture. Regular security communications and training educate employees on how to keep the Company's people, assets, and information secure. The PG&E Security Awareness and Training Program communicates and trains

coworkers on security standards, best practices, tips, and risks. This program helps employees understand the importance of protecting the people, information, and assets at PG&E. The Security Awareness and Training Program establishes employee engagement themes based on security assessments and threat intelligence information to reduce security risk.

Figure 59 – Examples of Active PG&E Government Partners

Security Controls: PG&E's natural gas operations incorporate significant risk management activities, including those that address cyber and physical attack threats. PG&E's Cybersecurity organization advises Gas on cybersecurity risk mitigation activities to protect information and operational technology, with a focus on control systems. PG&E's gas control systems are critical assets and therefore require higher levels of protection through security controls and mitigation improvements, which are reviewed and updated on an annual basis. PG&E has been working closely with the U.S. Department of Homeland Security's (DHS) Transportation Security Administration (TSA) in response to the TSA's evolving Security Directives (SD), initially issued in 2021, which require assessment and implementation of security measures. PG&E's Enterprise TSA Compliance has been leading and working cross functionally regarding the Company's response to TSA's SD's, which was a new regulation requirement after the 2021 Colonial Pipeline ransomware attack. Since then, PG&E has implemented numerous security program enhancements to advance compliance with the TSA SD's, including the deployment of sensors at critical Gas sites to enhance cybersecurity monitoring, migration of Gas assets to a dedicated Gas Domain Network, enhancement of controls for patching and access management, and strengthening the incident response playbook. Additionally, PG&E has received continuous approval from the TSA of its annual Cybersecurity Assessment Plan, which is PG&E's cybersecurity plan to execute and assess its effectiveness in meeting the TSA SD's.

Security Assessments & Exercises: Given continual security threats and the evolving sophistication of adversary attacks, PG&E's Security Program is regularly assessed to validate strategic direction and improve alignment with current industry best practices. Assessments and improvements can occur through participation in security events, such as site-specific tabletop exercises, regular member participation with the AGA, the Downstream Natural Gas Information Sharing and Analysis Center, TSA briefings and exercises. PG&E has worked closely with TSA in aligning with the SD Pipeline-2021-02

series. It is through the results of security exercises that PG&E is better able to identify and plan control improvements that strengthen Gas Safety.

Multiple cybersecurity teams routinely conduct different types of security risk assessments that evaluate the cybersecurity posture of Gas related hardware, software, data, and processes. These cybersecurity teams include, but are not limited to, Cybersecurity Solutions Analysts (CSAs), the Third-Party Security Review (TSR) Team, and the Software Review Board (SRB) Team.

For 2025, these teams accomplished the following for the Gas T&D functional area:

- CSA Team:
  - Four Production Risk Assessments;
  - Two Project Risk Assessments with corresponding Business Impact Assessments;
- The Third-Party Security Review (TSR) Team:
  - 24 TSR Assessments;
  - 445 TSR Engagements; and
- SRB Team:
  - 54 Software Review Board Reviews.

Following a December 2024 full-scale cyber and physical exercise simulating an attack on our critical infrastructure, facilities, data, and systems, an updated emergency response plan was developed. In 2025, cybersecurity teams remained committed and fully engaged, assisting with plan reviews and updates and preparing for future exercises to position PG&E and the Gas organization to minimize impact in the event of a security incident.

d) VALVE AUTOMATION

PG&E's Valve Automation Program is designed to accelerate emergency response and minimize the time of exposure in the event of an unintended release of gas. The Valve Automation Program allows certain gas transmission pipelines to be rapidly isolated through remote and automatic control valve technology. The program is working towards a goal of completing isolation zones by prioritizing projects based on criteria such as whether the isolation zone protects HCA or Class 3 or 4 non-HCA, if the pipeline diameter is greater than or equal to 12.75 inches, if there is an Impacted Occupancy Count (IOC) greater than 0, and if the project targets an estimated gas evacuation time of 30 minutes or less.

Installation of automated isolation capabilities on transmission pipelines in populated areas may reduce property damage and danger to emergency personnel and the public in the event of a pipeline rupture. Additionally, PG&E's control room personnel are trained to develop a "bias for action." This training helps them recognize and act on system conditions warranting immediate isolation of pipeline

systems. Planned SCADA installations are ongoing to increase system visibility [see *Section V.7.a. Gas System Operations and Control* for more information].

The Valve Automation Program continues to build upon the scope and principles in PG&E's Pipeline Safety Enhancement Plan that replaced, automated, and upgraded gas shut-off valves across PG&E's gas transmission system. Since starting in 2011, a total of 420 valve automations have been installed. In 2025, six valves were automated, increasing safety along 162 miles of gas transmission pipelines through the Valve Automation Program.

e) Emergency Preparedness and Response

i. Gas System Operations Control Room Management Manual

Gas Control is responsible for operational oversight of PG&E's gas pipeline system, including coordination of operations and maintenance activities and monitoring for abnormal and emergency conditions. Emergency response procedures guide immediate action to make safe actual or potential hazards to life or property. Gas Control can immediately initiate and execute shutdown zone plans or direct field personnel to respond to critical locations for the execution of manual valve operations. In addition, Gas Control notifies appropriate 911 agencies and departments within PG&E so that emergency response resources are informed and dispatched. PG&E's Gas Emergency Response process is documented primarily in the Gas System Operations Control Room Management Manual and the Gas Annex EMER-3003M [see *Section V.7.e.iii* for more information].

To maintain familiarity and compliance, and to aid in the management of abnormal and/or emergency operating conditions, PG&E regularly trains gas control personnel on the Gas System Operations Control Room Management Manual.

ii. Company Emergency Response Plan

The purpose of the Company Emergency Response Plan (CERP) is to guide the gas, electric, and power generation businesses with a safe, efficient, and coordinated response to an emergency. For changes to PG&E's CERP, please see Attachment 03.

The CERP provides a broad outline of PG&E's organizational structure and describes the activities undertaken in response to emergency situations. The CERP presents a response structure with clear roles and responsibilities and identifies coordination efforts with outside organizations (government, media, other gas and electric utilities, essential community services, vendors, public agencies, first responders and contractors).

The CERP follows a logical flow from general emergency response concepts and guidelines to specific emergency management organizational structure, roles, responsibilities and processes. When appropriate, the plan also references supporting procedures and other response materials.

In addition, PG&E maintains business continuity plans, which describe how PG&E will continue its critical business processes in the event of a disruption to facilities, technology, or personnel.

iii. GAS ANNEX EMER-3003M

The Gas Annex EMER-3003M provides detailed information about PG&E's response to gas emergencies. It supports the response to all emergencies broadly as "One PG&E" through the integration with the CERP and the other functional area emergency response plans, which are annexes to the CERP. For 2025 changes to PG&E's Gas Annex, please see Attachment 03.

The Gas Annex provides an outline of the Gas organizational structure and describes the activities undertaken in response to incidents. It provides a response structure with clear roles and responsibilities, a communication framework, and identifies coordination and response integration efforts with outside organizations and community first responder agencies.

The Gas Annex outlines gas specific criteria to PG&E's Incident Levels that are provided in the CERP. The Incident Levels categorize and support PG&E in understanding the complexity of an incident and the actions that may be employed at each level (e.g., emergency center activations, resources requests, etc.).

Figure 60 – PG&E's Gas Incident Classification Levels

To foster a consistent and well-coordinated response to emergencies, the Company has adopted the incident classification system shown in the figure above.

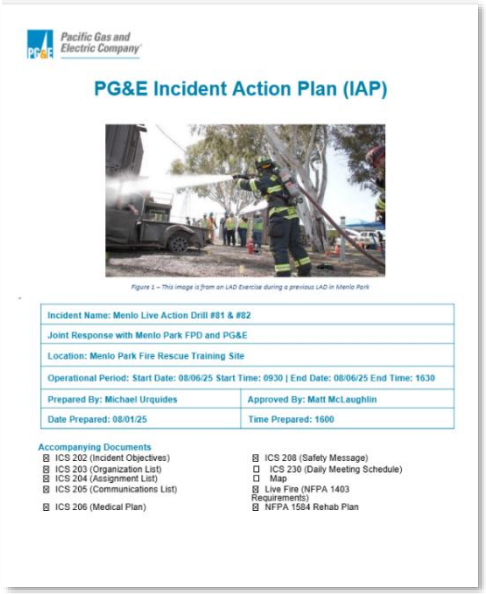
iv. EMERGENCY FIELD OPERATIONS TEAM

The Emergency Field Operations Team assists Gas with emergency planning, preparedness, response, and review. This group provides SME review of the Gas Annex, supports exercises, facilitates after-action reviews, and participates in industry activities designed to impart best practices. The group facilitates the use of the Incident Command System: a systematic, proactive approach for all levels of governmental and non-governmental organizations and the private sector to work together during an incident to reduce the loss of life, damage to property, and harm to the environment. Further, the team supports the Gas organization's local emergency response structure and deployment, the five regional Incident Management Teams (IMTs), and the five Gas Emergency Center teams. The IMTs and GEC are activated according to criteria outlined in PG&E's Gas Annex.

Frequent outreach to first responders helps strengthen how PG&E coordinates when emergencies happen. In 2025 Emergency Field Operations, Electric Operations, Public Safety Specialists and Grassroots Safety completed the efforts in partnership and close coordination with fire and law enforcement through Live Action Drills.

Throughout 2025, the Gas Emergency Response Group accomplished the following items:

- Delivered Incident Command System (ICS) 300 to emergency responders, ICS 400 training to three power generation IMTs, and table-top exercises for Elkhorn battery storage to three electric IMTs;
- Facilitated one full scale exercise of gas IMT, GEC, compression facility, gas control and a live action drill component, three well control tactical consideration functional exercises, and nine live action drills;
- Developed & Presented 10 IMT and GEC seminars that included table top exercises;
- Supported Southern California wildfires with GAS IMT activation, a No Gas Event in North Valley, Gas Valve leak L-132 SFO airport incident, and L-132 Inline Inspection repairs.


Pacific Gas and Electric Company

PG&E Incident Action Plan (IAP)

Incident Name: Menlo Live Action Drill #81 & #82	
Joint Response with Menlo Park FPD and PG&E	
Location: Menlo Park Fire Rescue Training Site	
Operational Period: Start Date: 08/06/25 Start Time: 0930 | End Date: 08/06/25 End Time: 1630	
Prepared By: Michael Urquides	Approved By: Matt McLaughlin
Date Prepared: 08/01/25	Time Prepared: 1600

Accompanying Documents

- ☒ ICS 202 (Incident Objectives)
- ☒ ICS 203 (Organization List)
- ☒ ICS 204 (Assignment List)
- ☒ ICS 205 (Communications List)
- ☒ ICS 206 (Medical Plan)
- ☒ ICS 208 (Safety Message)
- ☐ ICS 230 (Daily Meeting Schedule)
- ☐ Map
- ☒ Live Fire (NFPA 1403 Requirements)
- ☒ NFPA 1584 Rehab Plan

Figure 61 – Menlo Park Live Action Drill 2025

Figure 62 – Region 3 Alameda County Structure Fire Bay Area Gas IMT

Figure 63 – Region 3 Bay IMT Seminar/Tabletop Exercise

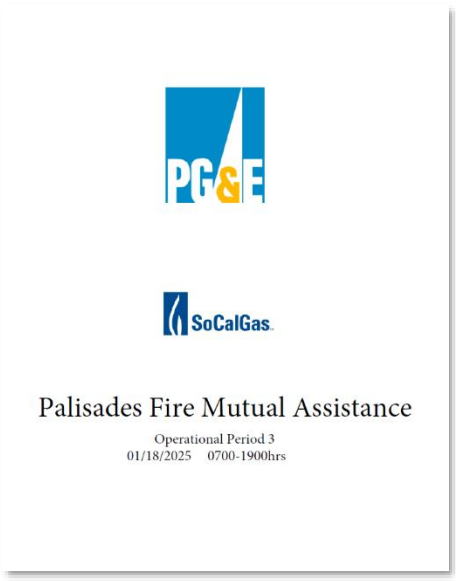


Figure 64 – Palisades Fire Gas Mutual Assistance Incident Action Plan

VI. Workforce

PG&E is committed to developing, training, and supporting a highly skilled team that is capable of safely constructing, operating, and maintaining the gas system. From an emphasis on strategically having the right mix of internal employees and contractors to meet annual work demands, to implementing a strong recruitment, retention, and onboarding process, the following sections have many examples that reflect a comprehensive approach to building, qualifying, and supporting a workforce that is fully equipped to achieve Gas Safety Excellence.

1. Workforce Size

PG&E's internal employee workforce works in conjunction with qualified contractors to perform quality work and maintain the safety of PG&E's gas system. Gas collaborates with Workforce Planning to determine the appropriate workforce size and types of roles that are required to fulfill annual work objectives. Talented employees are recruited, and, at times, the Company relies on the capabilities of various contracting firms during periods of peak or unique workload. PG&E has robust training programs and training facilities to develop its workforce so that each employee has the knowledge to perform his or her job safely and confidently [See *Section VI.2 Workforce Training* for more information]. Safety training starts on day one as part of new employee orientation and continues throughout each employee's career.

2. WORKFORCE TRAINING

PG&E's work requires well-trained personnel to perform activities in the correct way. The Company invests in recruiting and retaining skilled employees, provides ongoing development and training, and maintains supportive controls for employee and contractor work. Well-trained, fully engaged employees are essential for Gas Safety Excellence. Training is a key element of the PSEMS and in 2025 the focus of training was shifted from web-based trainings (WBT) to hands-on, skills-based refresher trainings, in addition to applicable apprenticeship training and relevant gas operator qualifications [See *Section VI.3 Gas Operator Qualifications* for more information].

PG&E's Gas Safety Academy in Winters, California, is a state-of-the art gas training facility that includes a utility village that provides realistic residential and commercial scenarios for leak survey, leak pinpointing, and emergency response, in line with the focus on hands-on trainings. Other features of the academy include the Miller® LiveArc™ welding performance management system with a simulation/pre-weld setup mode and live-arc training mode, allowing learners the opportunity to fine-tune their foundational welding skills, build confidence, become familiar with body mechanics, and build muscle memory prior to welding.

At the Gas Safety Academy, fundamental safety and code requirements are embedded within every course. Safety is non-negotiable and standards align with the requirements of federal OSHA, Cal/OSHA, National Commission for Certification of Crane Operators, NACE, American Weld Society, and the California Department of Motor Vehicles.

In 2025, the Gas Safety Academy facilitated over 17,000 student days at the technical, apprentice, and leadership levels. PG&E has developed or enhanced approximately 1,400 courses since 2012 (Table 27) and continuously updates and improves training content so that all classifications in Gas T&D have relevant initial and refresher training.

Table 27 – PG&E Number of Courses Developed or Enhanced from 2012 through 2024

2025	36
2024	30
2023	48
2022	47
2021	118
2020	224
2019	112
2018	122
2017	162
2016	214
2015	107
2014	78
2013	88
2012	14
Total	1,400

*Total does not represent total number of active courses

Workforce safety highlights from 2025 include:

- Completed the construction on a 700-foot pigging test loop in the Winters Training Facility. The test loop and associated training scenarios are designed to place students in actual Gas T&D pigging situations encountered in the field. The pigging test loop includes loading, unloading, pipe pressurization, and manipulation of the systems twin-lock door mechanisms. Identifying and responding to AOC's are also part of the training strategy.

- The Winters Training Facility completed the installation of six additional classrooms to accommodate increased training demand in Gas T&D and to provide space for operational groups such as Vegetation Management to host training.
- There was an increased focus on refresher training with an emphasis on hands-on scenarios and task-based activities. High-risk tasks identified and targeted included excavation safety and shoring, troubleshooting appliances, leak identification, and responding to dig-ins, cross bores, and other major gas events. Hands-on focus will continue into 2026 as PG&E reviews and updates the Utility Worker Program and other equipment-related training, such as rigging and hand signaling.

The goal of PG&E Academy is to provide the right training for the right people at the right time to safely and efficiently execute work. One way that the academy demonstrates this is to continuously maintain curriculum that mirrors current safety practices, procedures, regulatory requirements, and new equipment in the field. The recommendations in Table 28 are the output of a partnership between Gas SMEs and the PG&E Academy. High-risk, high-consequence tasks are identified by utilizing SME expertise so that the training mirrors actual field conditions and scenarios.

Table 28 – Gas Training Recommendations

Recommendations	
Develop programs that support employees throughout their career	• Courses developed and aligned to business need and results are measurable. • Completed and enhanced apprentice and new employee programs developed to advance employees to journey-level competency. • Increased focus on refresher training to maintain skill and competence of existing workforce.
Broaden technology solutions and leverage external curriculum	• Deployment of mobile web-based training solutions available on iPad and iPhone. • Performance support solutions available via portal platform and SharePoint for most functional areas in Gas Ops.
Implement continuous training improvement processes	• Gas Training Alignment Committee continues to mature and has provided an open forum for Gas T&D to introduce and discuss potential training needs and performance gaps. The Academy partnered with the Gas functional area and the Gas Qualifications department to develop technical training and qualification profiles for Gas employees for consistency amongst job classifications and to provide line of sight into who is trained and qualified to perform the work.

3. GAS OPERATOR QUALIFICATIONS

PG&E requires that all employees, contractors, and third-party installers of pipeline possess the qualifications necessary to perform tasks on pipeline facilities. A qualified operator has the expertise to complete work correctly and safely, supporting PG&E's commitment to public and employee safety. In 2025, the Gas Qualifications team qualified and/or requalified over 24,000 operator qualifications (OQ) tasks for PG&E employees and more than 2,500 qualifications for contractors.

Pipeline facility tasks require specific competencies to be performed safely and reliably. These competencies are defined as the "Knowledge, Skills, and Abilities" (KSAs) associated with each task. KSAs are developed by the OQ Development Team in collaboration with functional area Subject Matter Experts (SMEs).

The Gas Qualifications team is responsible for proctoring, evaluating, and qualifying individuals following the completion of their training. Individuals are assessed through written exams and hands-on performance evaluations. Candidates must achieve a minimum score of 80 percent on written exams and 100 percent on performance evaluations to be considered qualified. Evaluations focus on safety and the ability to recognize and respond to AOC's. Depending on the task and regulatory requirements, qualifications may be renewed every six months, one year, three years, or five years.

Personnel gain supervised field experience through their employers or PG&E training programs using task-specific Span-of-Control practices. During this experience, individuals work under the direction and observation of qualified personnel, not OQ evaluators, to develop the competencies required for qualification. Once trained and experienced, individuals are scheduled for formal evaluations through the Gas Qualifications Department. By maintaining a highly qualified workforce, PG&E can quickly and effectively recognize and respond to AOCs that may pose risks to the public, employees, or critical assets.

PG&E continues to enhance program consistency through strengthened oversight of contract partners by PG&E OQ representatives. These on-site visits verify that contractor evaluator practices remain aligned with PG&E's internal OQ requirements. During these visits, representatives observe live evaluations, provide targeted feedback, and identify opportunities for improvement.

This level of oversight reinforces program integrity and drives continuous enhancement of safety practices. The Gas Qualifications Department further strengthens the program each year by refining its processes to meet evolving operational and regulatory expectations. In 2025, PG&E's Gas Qualifications Department strengthened the safety and reliability of our operations by enhancing several qualification exams. These updates transitioned multiple evaluations from written only formats to a combination of written and hands on performance-based testing.

PG&E's Gas Qualifications Department also participates in benchmarking and continuous improvement collaborations with other utilities and industries nationwide. These partnerships help identify opportunities to further elevate workforce expertise and to advance PG&E's commitment to safety and continuous improvement.

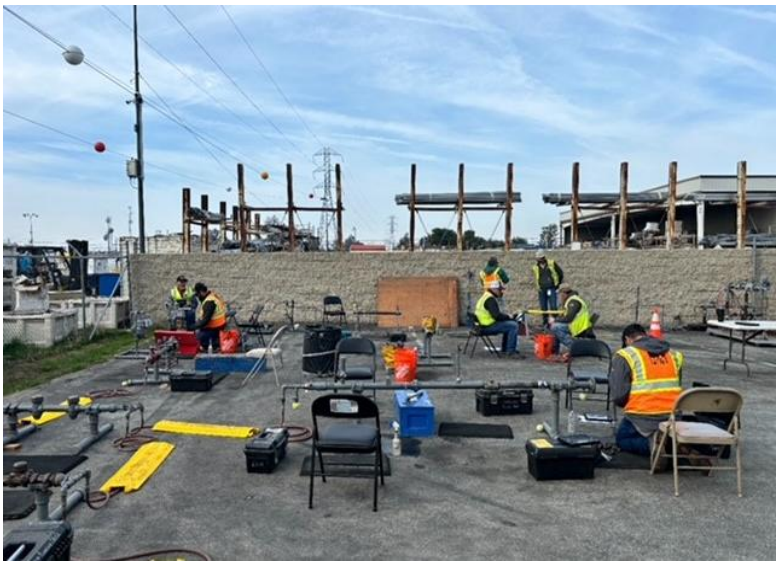


Figure 65 – Employees Taking Performance Operator Qualification Exam

4. CONTRACTOR SAFETY AND OVERSIGHT

Contractors are an important aspect of PG&E's technical workforce. Since contractors often work with PG&E assets and infrastructure that directly impacts employee and public safety, the Company holds contractors to the same standard of safety as PG&E employees. The Contractor Oversight Procedures follow a four-step process (Figure 66) for contractor safety and oversight.

Figure 66 – Four-Step Process to Contractor Safety and Oversight

Prior to starting a job, PG&E pre-qualifies contractors and subcontractors and confirms that they are qualified to complete contracted work through internal and International Suppliers Network (ISN) reviews. PG&E continues to improve its contractor pre-qualification process and to update it to meet and exceed corporate requirements. PG&E evaluates the contractor's qualifications and performance results, including a host of personnel injury performance metrics. As part of this qualification, contractors on major capital and expense projects, such as strength testing, pipe replacement, valve automation,

and ILI, are also given in-person and computer-based training on PG&E's quality and safety expectations and typical hazards associated with the work.

Once construction on a project has started, PG&E carries out a plan for contractor performance and clearly communicates contract terms that hold contractors accountable for safety and quality. Job-site observations start during pre-job walk-throughs to evaluate site specific hazards prior to starting work.

PG&E then schedules regular meetings with contractors to oversee their work and confirm expectations are met. In addition to regular oversight, PG&E inspects contractor work and a QA team randomly checks project completion from beginning to end. On a quarterly basis, PG&E's leadership and contractor leadership meet to understand opportunities to improve the overall Contractor Safety and Oversight Program, analyzing both quantitative and qualitative trends in data from on-site observations and inspections.

After the job is complete, PG&E evaluates the contractor's performance using a scorecard that includes metrics on safety performance and contractual obligations. Contractors also have the opportunity to provide feedback to PG&E through a similar scorecard.

Contractor performance is tracked throughout the year and compared to Company performance. In 2025, Contractors supporting Gas T&D reported 17 injuries that required treatment beyond First Aid. Additionally, Contractors reported 11 Preventable Motor Vehicle incidents. In 2025, the Gas Contractor Safety Team and the Gas Contract Owners continued to focus heavily on improving contractor incident reporting, tracking, and follow-up. The incident reporting improvements in the Contractor Incident Program showed a substantial increase in reporting of First Aids, OSHA, PMVI, Good Catches, Dig-In, and Property Damage. In 2025, Gas Contractor Safety continued to see rigorous and expanded reporting by PG&E's Contract partners. Contract partners continued to lead their own SIF investigations with support from functional areas and the Enterprise EH&S Cause Evaluation Teams. This was translated to increased ownership and self-identified corrective actions. Gas implemented an improved Project Specific Safety Plan and Programmatic Safety Plan for Medium and High-Risk Gas Contractors. This expanded contractor engagement resulted in increased hazard identification and rigorous pre-job planning.

As PG&E strives to improve project safety, quality and productivity, the Company takes every opportunity to acknowledge when people are doing things right and recognize them for their specific efforts, innovations, contributions, hard work, safe work practices, good decisions, great planning, timely completion, or any other specific accomplishment—no matter how small. In 2025, there were 651 "Good Catches" turned in from contract partners to PG&E's safety and construction management function, representing a 15.5 percent decrease compared to 2024. All individuals who submitted a "Good Catch" were recognized, and the "Good Catches" were shared during a weekly call with PG&E construction and

contractor leadership. Contractors are encouraged to continue to speak up to raise awareness and share best practices.

5. Partnership With Labor Unions

Union-represented employees make up more than 80% of employees in PG&E's Gas workforce and are integral to the Company providing safe and reliable gas service. PG&E works with its union partners to identify opportunities for training, process improvement, and other investments in the safety of its union-represented employees and the public. In 2025, PG&E continued to collaborate with union leadership leading to improvements, such as:

- Engaging with IBEW and ESC union business representatives on critical topics at Leadership Town Halls;
- Collaborating further to address and mitigate employee escalations and concerns;
- Working with ESC and IBEW partners to implement essential controls for hazardous energy sources;
- Continuing to develop employee expertise using human performance tools throughout the organization; and
- Working with IBEW on PowerPathways opportunities.

VII. Compliance Framework

The Ethics & Compliance (E&C) Maturity Model was developed in 2016. The model is derived from the Federal Sentencing Guidelines and the U.S. Department of Justice's Evaluation of Corporate Compliance Programs, both of which define the parameters of an effective E&C program. PG&E continues its focus that each functional area achieves Level 3 maturity in each of the following eight Maturity Model elements: Risk Assessment, Program Governance and Resources, Guidance Documents, Compliance Controls, Communications and Training, Monitoring and Auditing, Investigation and Response, and Enforcement and Incentives. The maturity level ratings between 1 and 5 are defined as: Initial (1), Defined and Built (2), Implemented (3), Managed (4), Optimized (5).

The Compliance Maturity Model is a framework to manage the overall compliance program. It provides Gas with a guideline on what an effective E&C program should look like. This approach aligns with the "Plan, Do, Check, Act" (PDCA) management method that PG&E employs throughout its operations as part of Gas Safety Excellence.

Gas has made significant progress since the initial baseline performance assessment was conducted in 2019 and has improved maturity scores in seven of the eight elements. The last maturity assessment was completed by Gas, in partnership with Ethics & Compliance, in 2021. The assessment resulted in an achievement of the enterprise expected maturity level 3 scores in six of the eight Compliance Maturity

Model Elements, an expected maturity level 1 for Element 4 - Compliance Controls and a downgraded maturity level 2 for Element 5 – Communications & Training.

Gas has implemented several improvements to the training program to remediate the Element 5 gap to meet the level 3 maturity milestones. Training validation was added to the annual Requirement Owner Certification for Requirement Owners to validate that trainings are in place as mandated by compliance requirements. A training analysis process was also implemented. In this process, the Compliance Team annually reviews the requirements inventory to identify requirements that mandate trainings and to validate that trainings are in place for those requirements. Table 29 provides the maturity level score progress in Gas for each of the eight elements since the inception of the Compliance Maturity Model.

Assessments were not conducted in the years 2022 through 2025 due to the Enterprise allowing functional areas to focus on completing remediation action items to improve their maturity scores. A limited scope assessment of Elements 1, 2, 3, and 5 is planned to be conducted in Q1 2026.

Table 29 – Gas Compliance Maturity Model – Assessment Scores by Element

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Element	**Baseline**	**3rd Party**	**3rd Party**	**3rd Party**	**3rd Party**	**PG&E**	**n/a**	**n/a**	**n/a**	**n/a**
1. Risk Assessment	3	2	3	2	2	3	Assessment not performed	Assessment not performed	Assessment not performed	Limited Scope Assessment for Element 1, 2, 3 and 5 planned for Q1 2026
2. Program Governance	2	2	2	2	3	3				
3. Governance Documents	2	2	3	1	1	3				
4. Compliance Controls	1	1	1	1	1	1				
5. Communications & Training	2	3	Not Assessed	1	3	2				
6. Monitoring & Auditing	2	2	3	2	3	3				
7. Investigations & Response	2	3	3	1	2	3				
8. Enforcement & Incentives	1	1	3	1	2	3				

Action Plans are developed annually to address gaps and to maintain or strengthen maturity scores. The 2025 Action Plan implemented improvement areas to enhance and re-implement the Work Group Evaluation (WGE) for self-identified non-compliance issues. Learnings and trends from the WGEs will be shared with leaders to identify root causes of non-compliance issues with the goal of preventing recurrence and driving down future nonconformances. In 2025, Gas also continued to implement the enterprise Compliance Requirement Prioritization Methodology with additional process teams to reassess the risk rankings of compliance requirements, which is used to prioritize compliance control

documentation and testing (Element 4). Additionally, Gas continued to document compliance controls for its critical, high, and medium risk compliance requirements.

While the Compliance Maturity Model structures PG&E's strategic approach to compliance, day-to-day compliance performance continues to be built upon these four key enablers:

- Employee expertise;
- Providing employees the right information at the right time;
- Making available the right resources at the right time; and
- Implementing supportive controls.

More information on each of these enablers can be found in the following sections.

1. Building Expertise

PG&E employees require specialized skills to perform their jobs of constructing, operating, and maintaining the natural gas system. As detailed in *Workforce Training* [see *Section VI.2*] and *Gas Operator Qualifications* [see *Section VI.3*], the Company recognizes that its employees are a critical element in the compliant operation of the pipeline system every day. Competent and capable employees perform work safely, effectively, and efficiently while using their knowledge and experience to identify and raise opportunities for continuous improvement. PG&E employees continuously receive a multitude of new and refresher trainings (both hands-on and web-based) and certifications. These trainings help employees stay current with new or changing regulations, internal standards, procedures, and work methodologies to enhance public safety.

2. The Right Information to Do the Work

A highly-skilled workforce is most effective when provided with timely, accurate information. Gas pipeline work is highly technical and, if not performed correctly, could result in serious safety concerns. To enable the consistent performance of work across the service territory, PG&E uses written guidance documents, such as standards, procedures, and job aids. These documents are stored electronically in the Technical Information Library (TIL) and are also available on mobile devices via the CORE mobile application. All documents are reviewed and updated routinely to reflect both regulatory requirements and best practices, as well as any lessons learned from Company or industry experiences. Additionally, these documents are available in real time to field employees and contractors via a mobile application, making access easy while on site.

In 2025, PG&E expanded automatic access to the mobile application to all Gas workers, enhancing their ability to review guidance while in the field. Additionally, PG&E continued publishing changes to the TIL each month. This approach allows PG&E to pace changes affecting people performing the work, and provides coworkers sufficient time to absorb each update between its publication date and effective

date. Email communications based on changes in several categories are sent as needed, allowing employees to determine relevant changes more efficiently. Additionally, each document change is assessed for impact and, depending on the assessment, is rolled out in a layered approach using multiple communication channels as appropriate. There are many channels utilized, such as simple emails or discussions from worker leadership, tailboards, direct group meetings with the people doing the work, or PG&E Academy training.

In addition to technical guidance, employees need accurate and timely information about PG&E's pipeline assets. PG&E has two pipeline GIS mapping systems — one for transmission assets and another for distribution assets. These systems contain geospatial information about the pipeline system including detailed information about asset history, materials, manufacturer, and location of the majority of assets. These systems help PG&E effectively conduct integrity management program work, locate mains and services, and plan for construction. PG&E works continuously to improve the quality of the information in both mapping systems. Given the volume of work performed on the pipeline systems every day, it is critical to have processes that update these mapping systems accurately and promptly.

3. The Right Resources to Do the Job

Once a portfolio of work has been identified and approved, the PG&E Gas Work & Resource Planning team determines the number of internal and external resources that will be needed to complete the portfolio of work safely and efficiently. PG&E maintains master agreements with multiple contractors as well as a database of construction qualifications to effectively assign work to the appropriate and most effective resources. The allocation of work is proposed by the Gas Work & Resource Planning team and then reviewed and confirmed by a broader "Work Allocation Team" that is made up of members from the Gas Sourcing, Engineering, Project and Program Management, Contract, and Construction Management teams who take into consideration workload, safety performance, and other factors when confirming resource assignments. PG&E uses workplans comparing the anticipated level of effort for planned work coupled with emergent work forecasts and compares that to internal resource capacity to signal the need for additional overtime, contractor resources, or any other needs required to safely complete the work as planned.

4. Supportive Controls

A compliant company relies on a range of processes and programs designed to support effective oversight, monitoring, and continuous improvement. Some of these processes focus on internal activities to meet compliance requirements, while others take an external view to help anticipate regulatory changes and identify improvement opportunities.

PG&E's Gas Regulatory Compliance performs multiple activities to support effective oversight with the CPUC Safety Enforcement Division (SED). These activities include conducting inspections, managing self-reports, overseeing safety-related condition and incident reports, and preparing required annual reports. Gas continues to analyze historical compliance data from SED inspections and self-reports to identify improvement opportunities. Using the process management framework and data analytics, the Regulatory Compliance team evaluates key compliance challenges and collaborates with Process Owners (POs) and Process Managers (PMs) to develop targeted action plans. These data-driven efforts have contributed to a decline in non-compliances since 2019. Through this work, Gas has developed quality assurance programs and is partnering with POs and PMs to implement additional process controls aimed at preventing nonconformances. This effort, paired with the Compliance Maturity Model described in Section VII (*Compliance Framework*), strengthens continuous improvement and reduces the likelihood of future non-compliance.

Figure 67 – Compliance Supportive Controls

Gas also places strong emphasis on self-identifying nonconformances to promote transparency with regulators and so that these events are treated as learning opportunities. PG&E has established processes to determine the apparent and contributing causes of nonconformances, leading to effective preventative and corrective actions. In 2025, PG&E continued a Notice of Violation/Nonconformance Command Center to centralize review of nonconformances, analyze causal factors, and oversee corrective action planning. This effort supports additional learning and advances continuous improvement. Collectively, these actions reinforce the Plan–Do–Check–Act methodology integrated into PG&E's compliance and quality management frameworks.

VIII. CONTINUOUS IMPROVEMENT

Continuous Improvement is the mechanism through which PG&E evolves from reactive to proactive in the journey to Gas Safety Excellence. By continuously using a critical eye on existing practices and identifying the cause of challenges that arise, PG&E can correct problems before they result in compliance violations or harm to PG&E employees or the public. While continuous improvement is embedded in PG&E, a few programs are highlighted below.

1. QUALITY MANAGEMENT

The Quality Management (QM) team plays a vital role in aligning all components of Gas T&D and their associated stakeholders to foster a culture of continuous improvement. Through collaboration and oversight, QM enhances organizational processes, services, and deliverables to support PG&E's mission of delivering safe, reliable, and affordable energy.

A core responsibility of the QM team is the implementation, improvement, and maturation of the Quality Management System (QMS). The QMS provides a structured framework for evaluating the effectiveness of controls established through the PG&E Safety Excellence Management System (PSEMS).

The figure below illustrates how the QMS aligns with the Element 13 (Assurance) of PSEMS, reinforcing a systematic and disciplined approach to quality and compliance across Gas T&D.

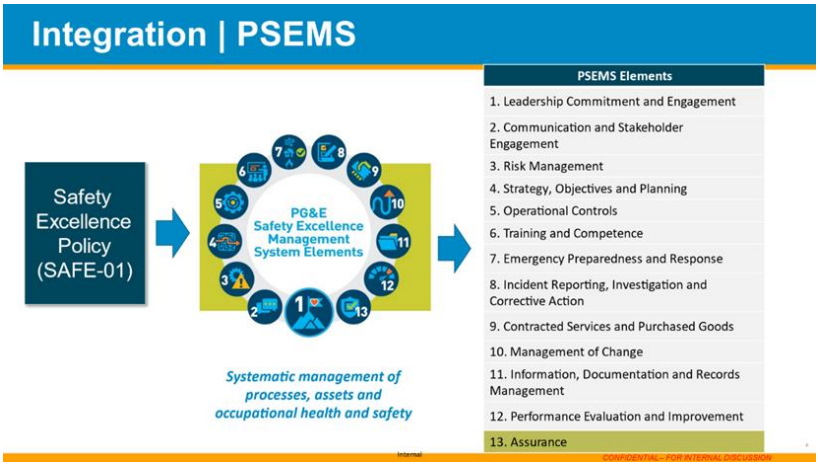


Figure 68 – Assurance Element in PSEMS

Gas Quality Management encompasses both Quality Assurance (QA) and Quality Control (QC) at the organizational level. These components, along with functional QC embedded within the various Gas work groups, all work together under the QMS framework to reduce defects and mitigate non-compliance risks.

- **Quality at the Source (QATS):** Builds quality into the process at the point where work is performed.
- **Quality Control (QC):** Focuses on identifying defects in the work being performed and the records generated during task execution.
- **Quality Verification (QV):** Evaluates work performed by functional teams through direct observation or post-completion assessment in the field.
- **Quality Assurance (QA):** Assesses the effectiveness of controls (including QC) by identifying records nonconformances in the overall work process.
- **QM Audits:** Aims to prevent defects by identifying process gaps and recommending corrective actions.

Together, QA and QC form a layered defense strategy that supports risk mitigation and continuous improvement.

Figure 69 illustrates this layered defense model framework.

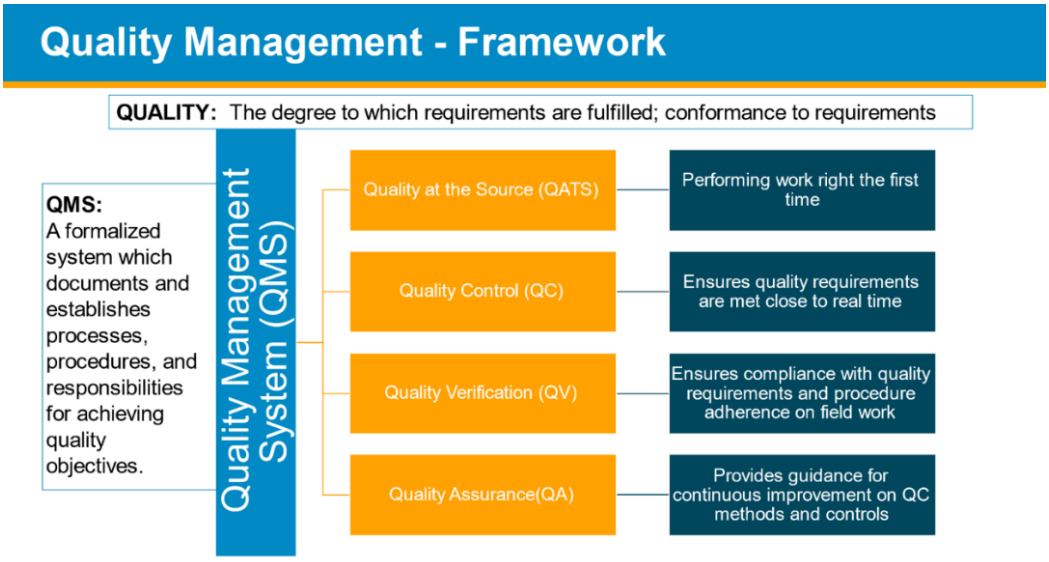


Figure 69 – Layers of Defense

The Quality Management System (QMS) provides a structured, collaborative framework that drives continuous improvement across Gas T&D. It promotes consistency by identifying nonconformances, recommending corrective actions, and reinforcing improvements through lessons learned, mentoring, and coaching, which supports both frontline personnel and leadership.

At the heart of the QMS is the **Plan–Do–Check–Act (PDCA)** cycle, a proven, iterative management method used to control and continuously improve processes and outcomes. Like a circle with no end, the PDCA cycle fosters a culture of on-going improvement and operational excellence.

Figure 70 illustrates the PDCA model and summarizes each phase of the cycle.

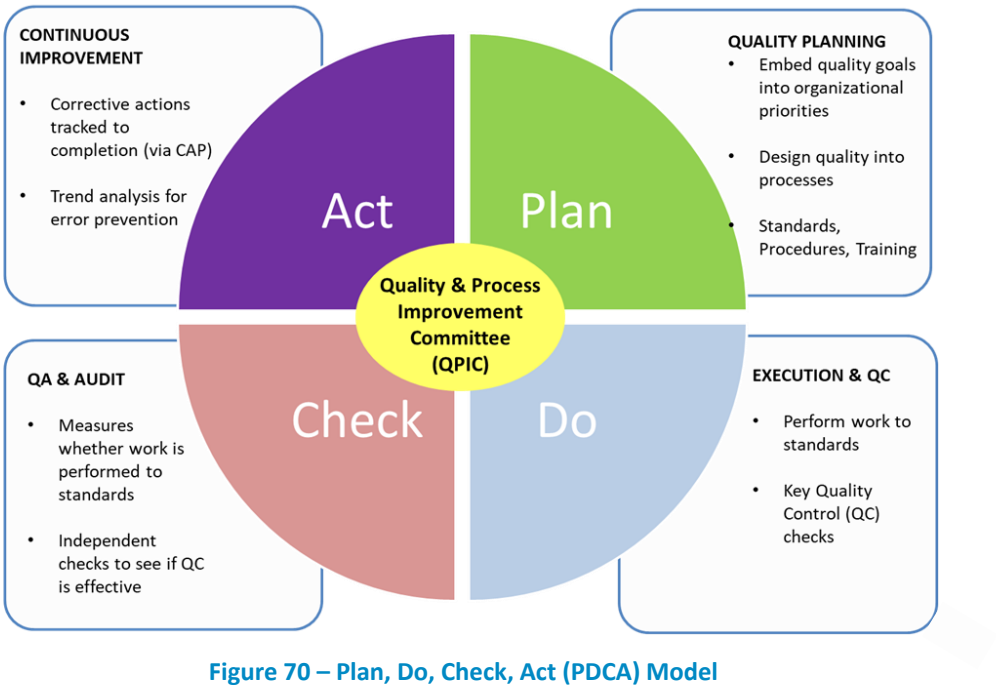


Figure 70 – Plan, Do, Check, Act (PDCA) Model

In 2025, Gas Quality Management assessment programs included 56 distinct programs that supported continuous improvement for Gas T&D. Table 30 outlines the distribution of quality oversight programs across Quality Control, Quality Assurance, and Quality Verification support.

Table 30 – 2025 QM Program Matrix

Organization	# of QM Assessment Programs (2025)
AKM	5
Construction	13
Gas T&D	28
Gas System Ops	10
Grand Total	**56**

In keeping with the Gas QMS maturity journey and expansion of our quality oversight, PG&E also accomplished the following in 2025:

- Performed over 106,000 QC assessments;
- Performed over 3,000 QA assessments;
- Performed over 1,900 QV assessments;
- Performed 14 QM Audits;
- Transitioned QC Construction As-Built team to Truecontext for QM alignment, more reliable data and reporting outputs;
- Successfully implemented Gas Clearence program to better assess T&D clearance adherence in the field;
- Added three Instrument Calibration attributes to all field programs to support Lloyds Registry Quality Assurance (LRQA) recommendations for company equipment;
- Completed effectiveness review for ILI Pigging via in-field assessments and established a baseline program for 2026;
- Supported Damage Prevention's SED OII by working with the functional areas and a 3rd party auditor to improve USA ticket processes and oversight;
- Developed and implemented the Quality Improvement Plan to focus on the most high-risk activities and looking for continuous improvement in these areas.

In 2025, Gas quality performance continued to be measured using two metrics: the error rate (QC) and the natural error rate (QA/QV). Both metrics counted all nonconformances equally, regardless of whether they were ranked as high, medium, or low risk. Error rates were calculated by dividing the number of nonconformances identified by the total number of items assessed. This approach allows for corrective actions to address all nonconformances, not just those classified as high risk. High-risk nonconformances remained a priority for Quality Management (QM), with Corrective Action Plans (CAPs) required for all QA and QV high-risk findings. Additionally, corrective actions for these high-risk issues continued to be closely monitored for timely resolution and that the corrective actions were effective.

The PG&E Gas Quality Management (QM) function is committed to the consistent delivery of safe, reliable, and affordable energy to customers. Through a structured and proactive approach, QM supports safety and quality across all aspects of Gas T&D by:

- Systematically monitoring and evaluating processes and work products;
- Having adherence to established standards and procedures;
- Identifying opportunities for improvement; and
- Verifying that corrective actions are effectively implemented.

This integrated approach minimizes operational risks, reduces costs, and enhances the safety of both the public and our workforce. By embedding quality into every layer of Gas T&D, QM drives continuous improvement and supports PG&E's broader mission of operational excellence.

2. Supplier Quality Assurance for Distribution and Transmission

The Supplier Quality Assurance (SQA) organization is responsible for assuring the safety and quality of material provided by PG&E's suppliers. If nonconforming material is purchased to be used in pressurized gas systems it might introduce a safety risk to employees, the public, and to the gas infrastructure. PG&E's SQA group collaborates with engineering, construction, and supply chain to enforce rigorous standards for incoming material and assures that qualified suppliers provide material that meets PG&E's product qualification requirements. SQA has significantly reduced Defective Parts Per Million (DPPM) since 2014. The 2025 DPPM performance was 165, beating our target of 290 by a significant margin. Lowering the target will not result in significant improvements to supplier quality, therefore the goal of 290 will not be revised in 2026. Additionally, changes to the target would increase operational costs, while simultaneously diminishing the benefit of quality-related activities.

SQA's QPR (Quality Performance Rating) metric is proactive monitoring of suppliers' improvement of overall performance including DPPM, responsiveness of suppliers' corrective actions, Quality Management System, and other technical quality parameters that will aid PG&E in reducing risk with more targeted quality efforts. In 2025, three suppliers who needed improvement were identified using the QPR assessment. With support, all three suppliers reached PG&E's acceptable quality level. In 2026, SQA plans to use QPR as the main quality metric, and QPR has been added to the Executive dashboard.

SQA is driving towards the ultimate goal of suppliers delivering defect-free material to PG&E. Ninety percent of high-risk gas material suppliers are ISO certified. SQA was re-certified to ISO 9001:2015 QMS in 2025 and had zero nonconformities for all audits. Through PG&E's cross functional teams and supplier partners, SQA processed 83 supplier change requests in 2025 and one supplier material recall. In addition, SQA conducts an annual supplier survey to identify improvement opportunities.

3. Research Development and Demonstration

The Research Development and Demonstration (RD&D) group brings innovative technologies and solutions from industry, government, and academia to PG&E's Gas functional area. RD&D, within the broader Grid Research, Innovation and Development (GRiD), prioritizes this work in alignment with PG&E's True North Strategy.[34] RD&D focuses on two primary themes: (1) Gas System Integrity, and (2) Decarbonization. Through these focus areas, RD&D supports improvements in safety, affordability, and reliability of the existing gas system, while also advancing understanding of clean fuels system opportunities. This work aligns with PG&E 2024 Research and Development (R&D) Strategy Report,[35]

complies with CPUC R&D Administrator requirements, and is coordinated with California investor-owned utility RD&D administrators to enable collaboration opportunities and avoid duplication of efforts.

PG&E collaborates with national and international R&D organizations and works closely with RD&D programs at the California Energy Commission (CEC), SoCalGas, PHMSA, the California Air Resources Board (CARB), the federal Department of Energy and multiple universities, mobilizing and leveraging a broad spectrum of expertise to bring innovative solutions to Gas in the most effective way.

In 2025, the RD&D and Innovation team managed and implemented a broad portfolio of nearly 160 projects in collaboration with leading U.S. and overseas utilities, pipeline operators and R&D organizations. Examples of 2025 achievements include:

Advanced safety in the natural gas system through targeted research and field validation projects. One project updated the emissions calculation methodology for Transmission Metering & Regulating (M&R) Stations, shifting from a population-based to a leak-based approach. This work involved deploying fixed-point laser sensors, direct site measurements, and continuous monitoring cameras, resulting in regulatory approval and a significant reduction in reported emissions. The improved methodology led to a 10 percent decrease in emissions and raised overall vented and fugitive emissions reduction from 42 percent to 52 percent compared to the original baseline.

A second project focused on integrating continuous methane monitoring solutions at underground storage facilities, enhancing early detection of high-risk leaks and reducing operational risks (Figure 71). By pioneering advanced quantification methods for methane emissions, Gas RD&D improved accuracy and regulatory compliance while also achieving substantial operational savings by eliminating daily wellhead leak surveys. Together, these initiatives demonstrate Gas RD&D's commitment to safety, emissions reduction, and operational excellence in the gas system.

Figure 71 – RD&D Performing Controlled Gas Releases to Test the Viability of the Methane Monitoring System

Demonstrated state-of-the-art vacuum purge technology that can be used in lieu of traditional purging methods. Traditional purging methods can pose safety risks to coworkers and result in emissions to the atmosphere. The vacuum system works by vacuuming out residual air in the pipeline before introducing natural gas. The system can enhance operational safety when purging new lines into service by reducing the chances of ignition and can reduce emissions resulting from traditional purging activities.

Figure 72 – ZEVAC and OTD Purging Units at the Winters Gas Safety Academy

Evaluated effectiveness of fixed gas detectors. In 2025, RD&D, leak survey and reservoir engineering evaluated the effectiveness of Emersons 625 IR fixed gas detectors (FGDs) for continuous leak monitoring in lieu of the daily wellhead leak survey. The 625 FGDs transmit infrared light to determine the ambient methane concentration which helps to identify early indicators of loss of containment and prevent potential hazards from escalating. Stationary methane monitors enhance safety due to 24/7 leak monitoring, reduce emissions by identifying leaks sooner, and promote affordability for rate payers by reducing associated costs with respect to daily wellhead leak surveys. Due to positive results, the leak monitoring system is currently being scaled to the entire facility for full implementation.

Developed and validated SPADE technology. The SPADE technology is developed for real-time detection and localization of mechanical impacts, illegal tapping, stray currents, and lightning strikes on operating pipelines. It does this by leveraging cathodic protection (CP) monitoring and integration with existing Remote Monitoring Units (RMUs), offering pipeline operators increased safety, reduced operational costs, improved reliability of alarm interpretation, and enhanced environmental protection (Figure 73). It complements other monitoring technologies by leveraging existing CP infrastructure for cost-effective pipeline integrity management. The field feasibility validation and pilot conducted at PG&E in agriculture areas subject to high risk of third-party damages has confirmed the SPADE System's ability

to detect mechanical impacts in real time, demonstrated long-term robustness under field conditions, and highlighted cost-benefit advantages compared to alternative monitoring approaches.

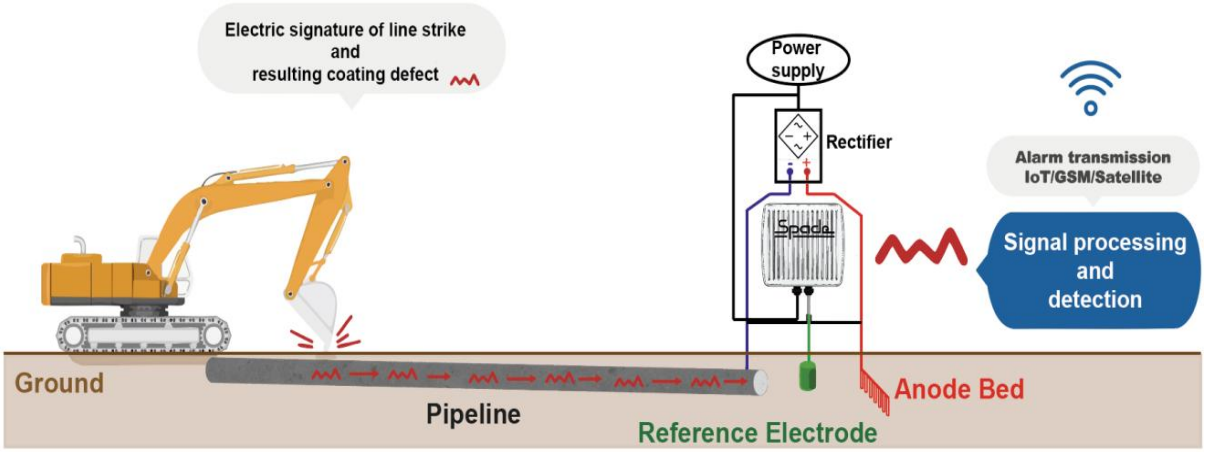


Figure 73 – Schematic of a SPADE System Installed on an Operating Pipeline, Showing an Excavator Impacting the Pipeline

Successfully conducted integrity survey using a boat-based sensor array. EMPIT's cutting-edge Current Magnetometry Inspection (CMI) technology is capable of pipeline 3D mapping, localizing and categorizing coating holiday and corrosion by using non-intrusive survey of underground pipeline magnetic field induced by a controlled alternating current. This technology enhances the accuracy, efficiency, and reliability of pipeline geolocating under challenging scenarios, overcomes the impact of AC/DC interference, and is complementary to the very costly pipeline external corrosion direct assessment (ECDA) or inline inspection, allowing for safer operations and reducing environmental impacts.

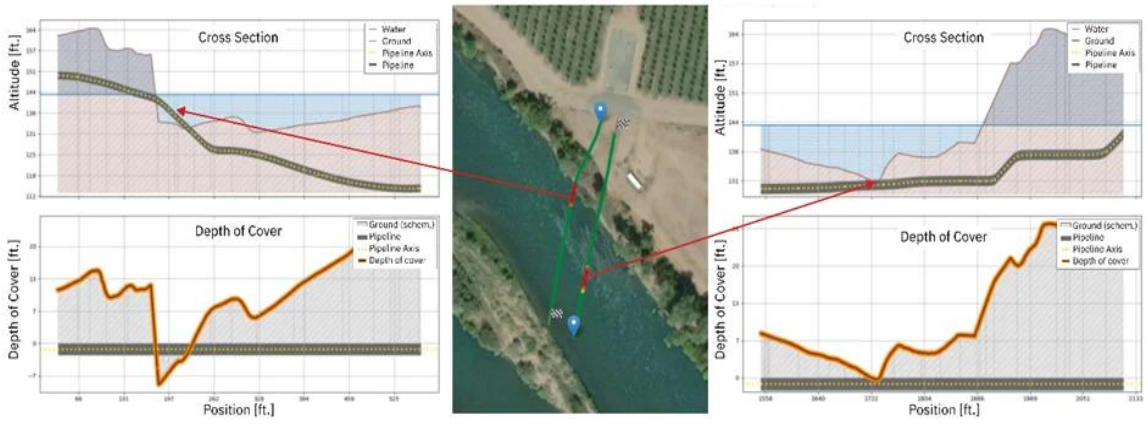


Figure 74 – Cross-Sectional Profiles Showing Water Level, Ground Surface, and Pipeline Elevation with Corresponding Depth of Cover. Left: Complete Exposure at Shore Transition. Right: Partial Exposure at River Center. Center: Aerial Overview with Inspection Locations.

The integrity survey used a boat-based sensor array, as shown above, at three exposed backbone pipelines at a Sacramento River Crossing site in Red Bluff and overcame the adverse water conditions and the close proximity of the pipelines that precluded any other techno-economically viable survey techniques, confirmed the increasing pipeline exposure at two distinct locations, and identified several coating anomalies with no immediate remediation requirements. Comparison of CMI-derived bending strain with existing ILI data demonstrated good agreement in both location and amplitude of principal bending features. This work provides PG&E with a techno-economically viable low-cost solution for inspection, monitoring, and assessment of pipeline integrity under challenging conditions.

Figure 75 – CMI Non-Intrusive Survey on Boat Platform at Sacramento River Crossing in Red Bluff

Continuous improvement for RD&D tools and methodologies.

1. Mechanical Impact Simulator for system verification, operator training, and periodic maintenance without physical excavation, making validation and calibration more practical and repeatable.
2. Event localization: By synchronizing multiple detectors along a pipeline, the system can now more accurately pinpoint the location of mechanical impacts, typically within 1.25 miles.
3. Enhanced Event Classification to distinguish between genuine mechanical impacts and other events (e.g., lightning, stray currents).
4. Real-time monitoring dashboard User Interface Upgrade including event alert notification via email/text message.
5. Incorporation of the existing commercial RMU functions, enabling consolidated CP monitoring and third-party damage detection within a single device.

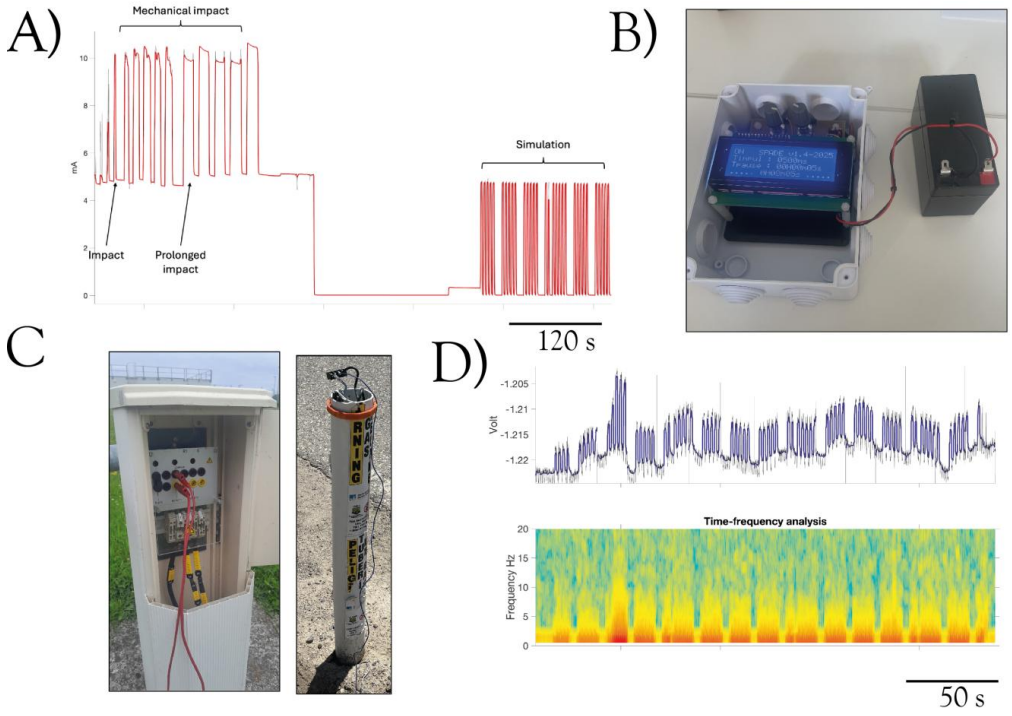


Figure 76 – A) Mechanical Impact Signal and Simulated Signal Generated by the Topper B) Signal Generator ('Topper') C) Topper Connection Points on the Rectifier D) Measurement of the Potential and Frequency Generated by the Topper

Looking ahead, RD&D will continue to plan for continuous improvement of event detection and classification algorithms, the accuracy of event localization, and the expansion of the pilot scale toward commercial deployment, supporting PG&E's ongoing commitment to safety and innovation.

4. Benchmarking and Best Practices

Benchmarking is an important step in PG&E's overall continuous improvement effort and is used to identify industry best practices. Best practices include, but are not limited to, widely recognized natural gas practices that directly enhance public and personnel safety over time. Benchmarking is one component of understanding what may constitute an industry best practice and is accomplished by both formal and informal means. There may also be more than one single industry "best practice" in any given program area. Therefore, PG&E's best practice identification often begins with identifying a published industry standard that provides guidance and sets overall direction for a program or technical discipline. When standards are not readily identifiable, PG&E may employ various methods, such as reaching out to industry associations, experts, and other utilities, to discuss best program approaches, and then develop detailed procedure manuals to document the practices. PG&E relies on various outlets for benchmarking best practices, such as reviewing standards written by SMEs and public agency publications and participating in industry associations. How PG&E utilizes each of these outlets is described in the following sections.

a) Industry Standards Written by Subject Matter Experts

One informal benchmarking practice that PG&E uses is identification and use of industry standards written and reviewed by SMEs. Sometimes these standards are referred to as "consensus" standards, meaning that the publisher believes that they represent proven practices in a given field. In addition to seeking best practice standards that originate in the U.S., PG&E identifies international standards for best practices, including European and ISO. PG&E uses several European standards and has both achieved and sustained the certification of ISO 55001, the international asset management standard.

PG&E relies on associations such as the American Gas Association (AGA), American Society of Mechanical Engineers (ASME), Interstate Natural Gas Association of America (INGAA), Public Service Enterprise Group (PSE&G), and the American Petroleum Institute (API) to facilitate the development of best practices, to prescribe codes and standards for the natural gas industry, to provide forums such as conferences and meetings for like members to learn about relevant best practices, to publish best practice literature, industry reports, and relevant industry statistics, and to provide technical continuing education. Some of PG&E's foundational risk management and gas program activities follow ASME standards and API consensus standards that are referenced in code, such as B31.8S, Managing System Integrity of Pipeline Systems and RP 1162, Public Awareness programs.

b) Agency Publications

PG&E reviews relevant agency documents to gain insight into what regulatory and investigation agencies view as best practices. PG&E incorporates input from previous proceedings and reviews, including the CPUC, NTSB, PHMSA, and reviewers contracted by these entities. As an example, PG&E has a procedure to have appropriate responses to PHMSA advisories and any proposed or final rulemaking notices from other regulatory agencies. The procedure expedites reviewing, assigning, and tracking of all Gas T&D related advisory bulletins and proposed or final rulemaking notices from any regulatory agency in a timely manner.

c) Peer Associations

Benchmarking is performed with a variety of utility and non-utility entities to improve PG&E's understanding of how other companies manage various operational programs, including best practices related to safety. For instance, PG&E personnel learn about best practices from interacting with peers and industry experts in other organizations.

PG&E employees participated in and presented at a variety of industry conferences. These conferences are gatherings of industry representatives with similar backgrounds to discuss best practices, review emerging practices, share operating information and build networks for future best practice sharing. In 2025, PG&E hosted over 200 peers from more than 20 utilities at the 2nd annual West

Coast Utility Best Practices Symposium. Presentation topics included System Risk, Evolving Emergency Response: Strengthening Preparedness, and Resilience in Gas T&D and SMS Maturity Through Knowledge Sharing.

d) American Gas Association

As part of PG&E's continuous improvement commitment to safety in Gas, the Company is an active member of the American Gas Association (AGA). The AGA helps PG&E share, validate and learn about gas safety best practices through targeted Operating Committees and Discussion groups with peer organizations. For example, PG&E actively participates in several AGA programs, including the Best Practices Program, the SOS Survey Program and the Employee & Vehicular Safety Survey. Participation involves both distributing and responding to topic-specific surveys and leveraging data provided by other U.S. gas utilities to inform safety improvements, operational performance, and benchmarking efforts.

Additionally, PG&E participated in the 2025 AGA Fall Committee Meetings and Pipeline Safety Management Systems (PSMS) Workshops. Presentations included discussions on how operators are implementing PSMS, how operators are working to review their PSMS program effectiveness, and how operators address any challenges they have experienced with implementing PSMS.

e) Interstate Natural Gas Association of America (INGAA)

The INGAA and the INGAA Foundation develop consensus guidelines and position papers based on the input of its members. PG&E considers these materials to constitute evidence of natural gas transmission pipeline companies' "best practices," and they are widely recognized in the industry as such. INGAA has a membership base that owns approximately 200,000 miles of natural gas pipeline in North America. PG&E leverages the INGAA Lessons Learned Program to review industry operating experiences and safety incidents, assessing whether similar risks exist within PG&E's operations and identifying opportunities for mitigation.

f) The Association for Materials Protection and Performance (AMPP)

PG&E relies on AMPP, formerly known as National Association of Corrosion Engineers (NACE), to identify and develop standards, test methods, and material recommendations that are widely regarded as the best in the field for corrosion, specifically for CP and coatings. AMPP creates these materials through the subject matter expertise of its members. AMPP has over 40,000 members across more than 130 countries.

g) Western Energy Institute

The Western Energy Institute (WEI) is the premier Western association of energy companies that implements strategic, member-driven forums, identifies critical industry issues, and facilitates dynamic

and timely employee development opportunities. WEI provides forums for exchanging timely information on critical industry issues and information about industry best practices and skills training. PG&E also participates on several committees.

h) Public Service Electric and Gas Company (PSE&G)

Public Service Electric and Gas Company (PSE&G) is a publicly traded diversified energy company headquartered in Newark, New Jersey that was established in 1985. In 1993, PSE&G developed a panel of companies for exchanging accurate and meaningful data on key performance metrics. One panel, the Gas and Electric Utility Peer Panel, is a collaborative effort among member utility companies that focus on sharing benchmark data on an annual basis. PG&E participates in the annual benchmarking study run by PSE&G and gathers valuable cost data. This data is then used in target setting for corresponding performance measures at PG&E.

i) Additional Benchmarking Efforts

In addition to participating in numerous associations, PG&E also develops benchmarking by using the expertise brought to the Company by new-hires and contractors with industry experience, by attending trade conferences, and through information sharing with other utilities.

In 2025 PG&E adopted HData, an artificial intelligence platform designed for the energy industry that uses AI and automation to centralize regulatory data from sources like FERC and the CPUC and offers searchable libraries of over 22,000,000 documents for regulatory topics. This new platform allows PG&E to quickly collect data from publicly filed documents and search for best practice information related to specific topics.

PG&E also uses benchmarking to facilitate continuous improvement. PG&E's participation in annual studies like the AGA Best Practices Program and AGA Employee & Vehicular Safety Information Survey provide benchmarking metrics to understand performance against peers. These studies include yearly special topics as well as repeating metrics that provide year-over-year trend information.

Industry performance also informs target setting. The following table lists a few key safety metrics that PG&E benchmarks against other utilities on an annual basis:

Table 31 – Key Benchmarking Metrics

PG&E's Commitment to Safety	Measurement
Emergency Response	Average response time
Leaks	Leaks repaired per customer
Employee Safety	DART Rate
Vehicular Safety	Preventable Motor Vehicle Accident Rate
Excavation Damages	Total number by 1st, 2nd and 3rd part
Gas Shut-In Time	Median Time
Gas Overpressure Events	Events per 1,000 pipeline miles

IX. CONCLUSION

PG&E's 2026 Gas Safety Plan demonstrates our commitment to and progress in implementing processes, programs, and procedures to achieve the stand of keeping everything and everyone always safe. PG&E's True North Strategy sets the tone for the Company to focus on people, the planet, and prosperity. The PSEMS guides how PG&E operates, conducts, and manages all parts of its business by putting the safety of the public, PG&E's customers, and PG&E's employees and contractors at the center of its work. PG&E maintains an asset management system to help address risks by tracking assets and their conditions, understanding the risks involving those assets, and developing and implementing risk reduction strategies with the intent to achieve risk reduction while balancing operational performance and costs. PG&E has made continued progress towards safety but recognizes that there is always more to be done in its journey to Gas Safety Excellence. We remain committed to continuously improving gas safety and to advancing safety management practices over time.

X. ENDNOTES

1 Tionesta Compressor Station is not counted in this number; the compressor unit was retired and removed from service in May 2025. The unit was isolated from the pipeline until full decommissioning and site clean-up can be achieved.

2 The compressor at Pleasant Creek Storage Facility is counted in this number although it has been isolated from the storage field. On July 18, 2023, PG&E, Pleasant Creek Gas Storage Holdings, LLC and eCORP Natural Gas Storage Holdings, LLC filed a Section 851 joint application with the CPUC for approval of the sale (Application (A.) 23-07-007). On April 24, 2025, the California Public Utilities Commission (CPUC or Commission) voted to approve the sale (Decision (D.) 25-04-032).

3 See Attachment 01 for a Table of Concordance that provides a mapping between the Pub. Util. Code Sections 961 and 963 and the Gas Safety Plan sections.

4 In October 2011, the California legislature signed into law SB 705, which declared "[i]t is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority." SB 705 was codified as Pub. Util. Code §§ 961 and 963(b)(3).

5 For the purposes of ILI, the formal GT-GIS 'Transmission designation' is used as the mileage denominator when calculating the overall percentage. The TP asset family includes distribution supply line (DSL) mileage, so the TPAF mileage is approximately 6400 miles. DSL is out-of-scope for ILI upgrade program.

6 This number of strength tested miles is inclusive of uprates, Facility Integrity Management Program strength tested miles, and class location strength tests.

7 An employee-led team that promotes safe work habits, shares information and best practices, promotes open and honest communications, and finds innovative methods to perform work safely.

8 This system was designed based on the elements of Process Safety developed by the Center for Chemical Process Safety, a branch of the American Institute of Chemical Engineers.

9 API RP 754 identifies leading and lagging indicators for nationwide public reporting, as well as indicators for use at individual facilities including methods for the development and use of performance indicators. This comprehensive leading and lagging indicators program provides useful information for driving improvement, and when acted upon contributes to reducing risks of major hazards (e.g., by identifying the underlying causes and taking action to prevent recurrence). The indicators are divided into four tiers that represent a leading and lagging continuum.

10 D.19-08-020 Approving Natural Gas Leak Abatement Program https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=311449621.

11 PG&E submits the Risk Spend Accountability Report annually every April in accordance with D.19-04-020.

12 API RP 1170, Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage. API RP 1170 provides functional recommendations and covers facility geomechanical assessments, cavern well design and drilling, solution mining techniques & operations, including monitoring, and maintenance practices.

13 API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. API RP 1171 recommends that operators manage integrity through monitoring, maintenance and remediation practices and applies specific integrity assessments on a case-by-case basis.

14 After several iterations, the most recent proposal was submitted for CalGEM review and approval on January 19, 2024.

15 The compressor at the Pleasant Creek storage facility has been isolated from the storage field. A Commission decision is pending on the sale of the facility.

16 The Transmission Pipe asset family includes transmission pipe and distribution supply lines (DSL), as well as valves and fittings outside of station boundaries and not otherwise included in the M&C asset family, which are those valves defined in TD-4551S – Station Critical Documentation. An example of valves included in the Transmission Pipe asset family includes manually operated mainline valves.

17 As set forth in 49 CFR Part 192, Subpart O.

18 Executive forums include the Executive Leadership Team meeting (the Chief Executive Officer (CEO) and her direct reports), the Senior Leadership Team meeting (the CEO, her direct reports, and their direct reports) and the Run the Business meeting (all PG&E officers).

19 The 2020 RAMP report reflected PG&E's first implementation of the methodologies adopted in the S-MAP Settlement Decision (D.18-12-014) which is the basis of the phase II OIR.

20 Transmission dig-ins are excluded from this metric due to the different asset type they represent and low volume.

21 49 CFR §192.614.

22 California Government Code §4216.

23 The term cross-bore is broadly defined as an intersection of an existing underground utility or underground structure by a second utility resulting in direct contact between the transactions of the utilities. The cross bore can compromise the integrity of either utility or underground structure. Examples include gas, telecom, water, storm, and sewer among others.

24 Due to the difference in timing when the Gas Safety Plan (GSP) report is due, these total percentage of miles of transmission pipe (including station transmission pipe) with test records are preliminary numbers that are not finalized and may not match other filings and the final PHMSA 7100 report.

25 Identified mileage does not include girth welds or branch connections. Additionally, it does not include the miles of pipe that would be necessary when pipe replacements are rolled into engineered projects.

26 The vintage pipe tier 1 miles are subject to change as PG&E gathers and updates data. The three projects PG&E submitted for the 2027 general rate gas are currently pending CPUC approval.

27 This program does not address the threats posed when natural gas pipelines that cross active earthquake faults. Please refer to PG&E's *Earthquake Fault Crossing Program* in *Section V.5.i*.

28 Metrics may change with the issuance of the PHMSA report.

29 Tensile stress is when equal and opposite forces are applied on a body, in this case a pipeline.

30 A full report about this incident from the National Transportation Safety Board can be found at this link: https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1902.pdf.

31 215 deaths related to the February 2021 winter storm in Texas were caused by extreme cold exposure, exacerbation of pre-existing illness, carbon monoxide exposure, or fire.

32 PG&E's California Gas Transmission Pipe Ranger website Supply and Demand Archives, https://www.pge.com/pipeline/en/operating-data/historical-archives/cgt-supplydemand-search.html. Enter a start date of "12/31/2025" and end date of "01/01/2025," download Excel file, and add values listed in "Total System Supply" row.

33 PG&E's California Gas Transmission Pipe Ranger website – OFO/EFO Historical Archives https://www.pge.com/pipeline/en/operating-data/historical-archives/ofo-archive.html (Year 2025).

34 True North Strategy - https://www.pgecorp.com/sustainability/corporate-sustainability/corporate_sustainability_report_2024/sustainability_2024/pges_triple_bottom_line.html.

35 2024 Research and Development (R&D) Strategy Report - https://www.pge.com/assets/pge/docs/about/pge-systems/pge-rd-strategy-report-2024.pdf.

XI. APPENDIX A – LIST OF FIGURES

XII. APPENDIX B – LIST OF TABLES

XIII. APPENDIX C – LIST OF ATTACHMENTS

Attachment 1 – Table of Concordance

Attachment 2 – Natural Gas Leak Abatement Compliance Plan

Attachment 3 – Change Logs for PG&E's Asset Management Plans, Gas Emergency Response Plan, and Company Emergency Response Plan

Attachment 4 – Change Log for 2026 Gas Safety Plan

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 1

TABLE OF CONCORDANCE

2025 Gas Safety Plan Table of Concordance

PG&E provides this Table of Concordance to demonstrate the Gas Safety Plan compliance with the Public Utility Code (PUC) Sections 961 and 963 (b)(3):

PUC Section	Section Location(s) in Gas Safety Plan
961 (a): For purposes of this section, "gas corporation workforce" means the employees of a gas corporation and employees of an independent contractor of the gas corporation while working under contract with the gas corporation.	VI. Workforce
961 (b) (1): Each gas corporation shall develop a plan for the safe and reliable operation of its commission-regulated gas pipeline facility that implements the policy of paragraph (3) of subdivision (b) of Section 963, subject to approval, modification, and adequate funding by the commission.	The 2026 Gas Safety Plan is submitted as required by this section.
961 (b) (2): By December 31, 2012, the commission shall review and accept, modify, or reject the plan for each gas corporation as part of a proceeding that includes a hearing. The commission shall build into any approved plan sufficient flexibility to redirect activities to respond to safety requirements.	Not applicable to PG&E.
961 (b) (3): Each gas corporation shall implement its approved plan.	The 2026 Gas Safety Plan provides a view into the safety activities PG&E pursues every day and highlights the specific safety work performed in 2025.

PUC Section	Section Location(s) in Gas Safety Plan
961 (b) (4): The commission shall require each gas corporation to periodically review and update the plan, and the commission shall review and accept, modify, or reject an updated plan at regular intervals thereafter. The commission, pursuant to Section 1701.1, shall determine whether a proceeding on a proposed update to a plan requires a hearing, consistent with subdivision (e).	PG&E reviews and updates its Gas Safety Plan on an annual basis. See I. Introduction.
961 (c): The plan developed, approved, and implemented pursuant to subdivision (b) shall be consistent with best practices in the gas industry and with federal pipeline safety statutes as set forth in Chapter 601 (commencing with Section 60101) of Subtitle VIII of Title 49 of the United States Code and the regulations adopted by the United States Department of Transportation pursuant to those statutes.	References to programs that comply with federal pipeline safety statutes and/or conform to industry best practices are referenced throughout the document as applicable.
961 (d): The plan developed, approved, and implemented pursuant to subdivision (b) shall set forth how the gas corporation will implement the policy established in paragraph (3) of subdivision (b) of Section 963 and achieve each of the following:	
961 (d) (1): Identify and minimize hazards and systemic risks in order to minimize accidents, explosions, fires, and dangerous conditions, and protect the public and the gas corporation workforce.	I. 3. PG&E Safety Excellence Management System I. 4. Public Safety I. 5. Workforce Safety I. 6. Rewarding Safety Excellence II. Safety Culture II. 2. Corrective Action Program II. 3. PG&E Company and Gas Safety Committees II. 3. a. Gas Safety Council II. 3. b. Gas Grassroots Safety Teams

PUC Section	Section Location(s) in Gas Safety Plan
	III. Process Safety IV. Gas Leak Abatement Plan V. 2. d. Measurement and Control (M&C) V. 3. Risk Management Process V. 5. a. Damage Prevention (throughout sub-sections) V. 5. c. Distribution Pipe Replacement V. 5. f. Vintage Pipe Replacement V. 5. g. In-Line Inspection V. 5. h. Corrosion Control V. 5. j. Leak Survey V. 5. k. Leak Repair V. 5. l. Overpressure Elimination Initiative V. 7. Mitigating the Risk of Inadequate Response and Recovery V. 7. c. Security V. 7. d. Valve Automation VI. Workforce
961 (d) (2): Identify the safety-related systems that will be deployed to minimize hazards, including adequate documentation of the commission-regulated gas pipeline facility history and capability.	V. 4. Records and Information Management V. 5. e. Strength Testing VII. Compliance Framework VIII. 1. Quality Management VIII. Continuous Improvement

PUC Section	Section Location(s) in Gas Safety Plan
961 (d) (3): Provide adequate storage and transportation capacity to reliably and safely deliver gas to all customers consistent with rules authorized by the commission governing core and noncore reliability and curtailment, including provisions for expansion, replacement, preventive maintenance, and reactive maintenance and repair of its commission-regulated gas pipeline facility.	V. 2. a. Gas Storage V. 2. b. Compression and Processing V. 2. c. Transmission Pipe V. 2. d. Measurement and Control (M&C) V. 2. e. Distribution Mains and Services V. 2. f. Customer Connected Equipment V. 2. g. Liquefied Natural Gas and Compressed Natural Gas V. 5. Mitigating the Risk of Loss of Containment V. 6. Mitigating the Risk of Loss of Supply (throughout sub-sections) V. 7. a. Gas Systems Operations and Control VIII. 1. Quality Management
961 (d) (4): Provide for effective patrol and inspection of the commission-regulated gas pipeline facility to detect leaks and other compromised facility conditions and to effect timely repairs.	V. 5. a. Damage Prevention (throughout sub-sections) V. 5. d. Cross-Bore Mitigation V. 5. e. Strength Testing V. 5. g. In-Line Inspection V. 5. j. Leak Survey V. 5. k. Leak Repair V. 7. a. Gas System Operations and Control

PUC Section	Section Location(s) in Gas Safety Plan
961 (d) (5): Provide for appropriate and effective system controls, with respect to both equipment and personnel procedures, to limit the damage from accidents, explosions, fires, and dangerous conditions.	I. 3. PG&E Safety Excellence Management System II. 2. d. Material Problem Reporting III. Process Safety V. 2. f. Customer Connected Equipment V. 2. g. Liquefied Natural Gas and Compressed Natural Gas V. 5. l. Overpressure Elimination Initiative V. 7. Mitigating the Risk of Inadequate Response and Recovery V. 7. a. Gas System Operations and Control V. 7. b. Clearance Operations V. 7. c. Security V. 7. d. Valve Automation V. 7. e. Emergency Preparedness and Response VI. 2. Workforce Training VI. 3. Gas Operator Qualifications VI. 4. Contractor Safety and Oversight VII. 4. Supportive Controls VIII. 2. Supplier Quality Assurance for Distribution and Transmission VIII. 4. Benchmarking and Best Practices

PUC Section	Section Location(s) in Gas Safety Plan
961 (d) (6): Provide timely response to customer and employee reports of leaks and other hazardous conditions and emergency events, including disconnection, reconnection, and pilot-lighting procedures.	I. 4. Public Safety V. 5. a. Damage Prevention (throughout sub-sections) V. 5. k. Leak Repair V. 7. Mitigating the Risk of Inadequate Response and Recovery V. 7. a. Gas Systems Operations and Control V. 7. d. Valve Automation V. 7. e. Emergency Preparedness and Response (throughout sub-sections)
961 (d) (7): Include appropriate protocols for determining maximum allowable operating pressures on relevant pipeline segments, including all necessary documentation affecting the calculation of maximum allowable operating pressures.	V. 2. b. Compression and Processing V. 5. e. Strength Testing V. 5. l. Overpressure Elimination Initiative V. 7. a. Gas System Operations and Control V. 7. b. Clearance Operations
961 (d) (8): Prepare for, or minimize damage from, and respond to, earthquakes and other major events.	V. 5. i. Earthquake Fault Crossings V. 7. Mitigating the Risk of Inadequate Response and Recovery V. 7. e. Emergency Preparedness and Response
961 (d) (9): Meet or exceed the minimum standards for safe design, construction, installation, operation, and maintenance of gas transmission and distribution facilities prescribed by regulations issued by the United States Department of Transportation in Part 192 (commencing with Section 192.1) of Title 49 of the Code of Federal Regulations.	I. 3. a. Gas Independent Third-Party Certification to Industry Standards I. 3. b. Safety Management System Maturity III. Process Safety V. Asset Management (throughout sub-sections) V. 5. Mitigating the Risk of Loss of Containment

PUC Section	Section Location(s) in Gas Safety Plan
	V. 5. m. Community Pipeline Safety Initiative IV. 5. n. Gas Transmission Vegetation Management
961 (d) (10): Ensure an adequately sized, qualified, and properly trained gas corporation workforce to carry out the plan.	VI. Workforce VI. 1. Workforce Size VII. 1. Building Expertise VII. 2. The Right Information To Do The Job VII. 3. The Right Resources To Do The Job
961 (d) (11): Any additional matter that the commission determines should be included in the plan.	PG&E is not aware of any additional matters the commission has requested be included.
961 (e): The commission and gas corporation shall provide opportunities for meaningful, substantial, and ongoing participation by the gas corporation workforce in the development and implementation of the plan, with the objective of developing an industrywide culture of safety that will minimize accidents, explosions, fires, and dangerous conditions for the protection of the public and the gas corporation workforce.	I. 3. PG&E Safety Excellence Management System II. Safety Culture (throughout sub-sections) VI. 2. Workforce Training VI. 5. Partnership with Labor Unions VII. 1. Building Expertise VIII. 3. Research Development and Demonstration VIII. 4. Benchmarking and Best Practices

PUC Section	Section Location(s) in Gas Safety Plan
961 (f): Nothing in this section limits the obligation of a gas corporation to provide adequate service and facilities for the convenience of the public and its employees pursuant to Section 451 or the authority of the commission to enforce that obligation under state law.	Not applicable.
963 (b) (3): It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.	The contents of PG&E's Gas Safety Plan provide a view into the safety activities PG&E pursues every day and highlights the specific safety work performed in 2025. This Plan explains how PG&E puts the safety of the public, customers, employees, and contractors first, and how the Company has made safety investments in processes and infrastructure that are consistent with best practices in the gas industry.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 2

NATURAL GAS LEAK ABATEMENT COMPLIANCE PLAN

PACIFIC GAS AND ELECTRIC COMPANY
2026 LEAK ABATEMENT COMPLIANCE PLAN
MARCH 13, 2026

SECTION A: PLAN INTRODUCTION AND SUMMARY

On January 22, 2015, the California Public Utilities Commission (CPUC or Commission) issued the Order Instituting Rulemaking (OIR) (R.) 15-01-008 to implement the provisions of Senate Bill (SB) 1371 (Statutes 2014, Chapter 525). SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities consistent with Public Utilities Code § 961(d), § 192.703(c) of Subpart M of Title 49 of the Code of Federal Regulations (CFR), the Commission's General Order (GO) 112-F, and the state's goal of reducing GHG emissions. In the June 15, 2017, Decision (D.) 17-06-015, the Commission adopted 26 Best Practices (BP) related to natural gas leak abatement (phase one). In August 2019, the Commission's Phase II Decision (D. 19-08-020) adopted a restriction on rate recovery beginning in 2025, for methane emissions greater than 20% below the 2015 baseline levels for Pacific Gas and Electric Company (PG&E) and SoCalGas, to ensure that expenditures authorized to implement their Compliance Plans achieve their intended methane emissions reductions.

PG&E submits this Leak Abatement Compliance Plan (2026 Compliance Plan) pursuant to Senate Bill (SB) 1371, which requires gas utilities to file biennial plans demonstrating progress toward minimizing methane emissions through implementation of the 26 Best Practices. This plan builds on prior CPUC-approved compliance plans, and outlines PG&E's actions, governance processes, and continuous-improvement efforts to reduce methane emissions across its natural gas system. This 2026 Compliance Plan is the fifth biennial plan and covers the years 2026-2027.

As of Reporting Year 2024, PG&E reduced methane emissions by 52.2% relative to the adjusted 2015 baseline, exceeding the 2025 compliance goal of 20% reduction. Since 2018, PG&E has implemented a series of measures under previous compliance plans. These key measures are listed in the table below.

Table 1 – Key Measures and Actions by Compliance Period (2018–2025)

Compliance Period	Key Measures/Actions
2018-2019	• Accelerated detection and repair of large leaks on the distribution system through the Super Emitter (SE) Program • Accelerated distribution system compliance survey from 5 to 3 years • Cross compression and drafting practices on backbone transmission pipeline projects • Replacement of 100+ high bleed pneumatic devices • Quarterly surveys at compressor stations and storage facilities
2020-2021	• Meter set leak bubble classification and repair prioritization • Project bundling to minimize blowdown emissions • Extending cross compression to local transmission projects
2022-2023	• Lowering Super Emitter threshold from 10 to 7 scfh prioritizing more large leaks for repair • Leveraging Super Emitter drives for DIMP vintage pipeline surveys • Replacing 10 high bleed pneumatic devices • Extending blowdown strategies to compressor stations and storage facilities
2024-2025	• Further reduction of Super Emitter threshold from 7 to 6 to 5 scfh prioritizing more large leaks for repair • Replacing 17 high bleed pneumatic devices • Prioritizing repair of outdoor meter set Class B leaks • Transitioning to a component-level methodology for Transmission Metering and Regulating (M&R) stations

Baseline Adjustment

Since the NGLA reporting process began, CPUC, the California Air Resources Board (CARB) and PG&E have collaborated to adjust the 2015 baseline emissions to incorporate improved measurement and estimation methods. These adjustments enable more accurate calculation of emission reductions and cost-effectiveness evaluations, ensuring alignment with CPUC Joint Annual Reports and California's climate goals.

The CPUC Safety Policy Division (SPD) has approved several baseline adjustments, as shown in Tables 2 through 4 below.

Table 2 – 2015 Baseline Adjustment Approved in 2022

Appendix	System Category	Emission Source Category	Original 2015 Baseline Emissions (Mscf)	Adjusted 2015 Baseline Emissions (Mscf)
3	Transmission Compressor Stations	Component Vented Emissions	N/A	10,172
		Component Fugitive Leaks	15,823	16,928
4	Distribution Mains and Services Pipelines	All Damages (Fugitives)	146,335	141,102
5	Distribution Metering and Regulating Stations	Station Leaks & Emissions (Fugitives)	741,986	9,440
6	Meter Set Assemblies	Meter Leaks (Fugitives)	636,034	245,907
		All Damages (Fugitives)	N/A	5,233
7	Underground Storage	Storage Leaks & Emissions (Fugitives)	11,870	2,036
		Component Vented Emissions	N/A	86,681
		Component Fugitive Leaks	10,574	75,957
		Dehydrator Vent Emissions (Fugitives)	6,761	13

Table 3 – 2015 Baseline Adjustments Approved in 2023

Appendix	System Category	Emission Source Category	Original 2015 Baseline Emissions (Mscf)	Adjusted 2015 Baseline Emissions (Mscf)
1	Transmission Pipelines	Component Vented Emissions	4,591	35,912
4	Distribution Mains & Service	Pipeline Leaks (Fugitives)	626,590	481,638

Table 4 – 2015 Baseline Adjustments Approved in 2025

Appendix	System Category	Emission Source Category	Original 2015 Baseline Emissions (Mscf)	Adjusted 2015 Baseline Emissions (Mscf)
2	Transmission M&R Stations	Station Leaks & Emissions	579,240	N/A
		Component Vented Emissions	N/A	31,545
		Component Fugitive Leaks	N/A	8,831

With these baseline adjustments and current programs/measures in place—including Transmission Blowdown Abatement Strategies, Super Emitter Program, Damage Prevention Program, and implementation of the CARB Oil & Gas Rule—PG&E has exceeded the 2025 compliance goal of achieving a 20% reduction compared to the adjusted 2015 baseline. To maintain this progress, PG&E will explore the following measures:

- Optimize the Super Emitter program through threshold and/or survey frequency adjustments
- Measurement and Control (or Regulator) station leak and emission management
- Continuous prioritization of the Distribution Main & Service leaks repair based on size estimated from vehicle-based measurements
- Meter set Class B leak repair prioritization
- Expand blowdown reduction strategies to additional Metering & Regulating Stations, Compressor Stations, and Underground Storage facilities

2015 Baseline vs. Reporting Year (RY) 2024 Emissions, including Supporting Best Practices

Table 5 shows the 2015 Baseline emissions vs. the RY 2024 emissions. Compared to the currently approved adjusted 2015 baseline, emissions in 2024 decreased by 52.2%

Table 5 - Total Emissions Comparing 2015 Adjusted Baseline with RY 2024 Emissions	
Approved Adjusted 2015 Baseline (Mscf)	1,665,960
2024 Total Annual Volume of Leaks & Emissions (Mscf)	796,118
Comparison with Adjusted Baseline	52.2%

Table 6 compares the 2015 baseline emissions with the 2024 reported emissions, as reported in PG&E's 2024 Natural Gas Leak Abatement Annual Report, for each system category and the Best Practices supporting emissions reduction. At this time, projections for 2025 emissions are unavailable and will be submitted on June 15, 2026 in PG&E's Natural Gas Leak Abatement Annual Report.

Table 6 - 2015 Baseline vs. RY 2024 Emissions, including Supporting Best Practice

System Categories	Emission Source Categories	Fugitive or Vented	For Informational and Reference Purposes Only:Original 2015 Baseline Emissions (Mscf)	Approved Adjusted 2015 Baseline Emissions (Mscf)	2024 Total Annual Volume of Leaks & Emissions (Mscf)	Percentage Change for Year Over Year Comparison from Approved Adjusted 2015 Baseline to 2024	Best Practice Support Emissions Reduction
Transmission Pipelines	Pipeline Leaks	Fugitive	3,701	3,701	2,039	-44.9%	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It
	All Damages	Fugitive	81,793	81,793	38,970	-52.4%	BP 24 - Dig-Ins / Public Education Program BP 25 - Dig-Ins / Company Standby Monitors BP 26 - Dig-Ins / Repeat Offenders
	Blowdowns	Vented	251,227	251,227	29,377	-88.3%	BP 3 - Pressure Reduction Policy BP 4 - Project Scheduling Policy BP 5 - Methane Evacuation Procedure BP 6 - Methane Evacuation Work Order Policy BP 7 - Bundling Work Policy BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Emissions	Vented	4,591	35,912	17,442	-51.4%	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Leaks	Fugitive	N/A	N/A	N/A	N/A	N/A
	Odorizers	Vented	135	135	133	-1.5%	N/A
Transmission M&R Stations	Station Leaks & Emissions	Fugitive	579,240	579,240	N/A	N/A	N/A
	Component Emissions	Vented	N/A	31,545	25,718	-18.5%	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Leaks	Fugitive	N/A	8,831	3,305	-62.6%	BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It
	Blowdowns	Vented	65,456	65,456	9,517	-85.5%	n/a
Transmission Compressor Stations	Compressor Emissions	Vented	70,186	70,186	6,241	-91.1%	BP 23 - Minimize Emissions from Operations, Maintenance and Ot her Activities
	Compressor Leaks	Fugitive	N/A	N/A	N/A	N/A	N/A
	Blowdowns	Vented	19,864	19,864	39,190	97.3%	BP 3 - Pressure Reduction Policy BP 4 - Project Scheduling Policy BP 5 - Methane Evacuation Procedure BP 6 - Methane Evacuation Work Order Policy BP 7 - Bundling Work Policy BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Emissions	Vented	N/A	10,172	4,541	-55.4%	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Leaks	Fugitive	15,823	16,928	17,839	5.4%	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It BP 22 - Pipe Fitting Specifications
	Storage Tank Leaks & Emissions	Vented	N/A	N/A	N/A	0.0%	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It
Distribution Main & Service Pipelines	Pipeline Leaks	Fugitive	626,590	481,638	242,895	-49.6%	BP 15 - Gas Distribution Leak Surveys BP 16 - Special Leak Surveys BP 21 - Find It/Fix It BP 22 - Pipe Fitting Specifications
	All Damages	Fugitive	146,335	141,102	60,167	-57.4%	BP 24 - Dig-Ins / Public Education Program BP 25 - Dig-Ins / Company Standby Monitors BP 26 - Dig-Ins / Repeat Offenders
	Blowdowns	Vented	141	141	624	342.6%	N/A
	Component Emissions	Vented	N/A	N/A	N/A	N/A	N/A
	Component Leaks	Fugitive	N/A	N/A	N/A	N/A	N/A
Distribution M&R Stations	tation Leaks & Emissions - Leak-Based	Fugitive	741,986	9,440	7,593	-19.6%	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It BP 22 - Pipe Fitting Specifications
	All Damages	Fugitive	N/A	N/A	51	N/A	N/A
	Blowdowns	Vented	147	147	240	63.3%	N/A
Customer Meters	Meter Leaks - Leak-Based	Fugitive	636,034	245,907	193,702	-21.2%	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It BP 22 - Pipe Fitting Specifications
	All Damages	Fugitive	N/A	5,233	1,108	-78.8%	BP 24 - Dig-Ins / Public Education Program BP 25 - Dig- Ins / Company Standby Monitors BP 26 - Dig-Ins / Repeat Offenders
	Vented Emissions	Vented	231	231	168	-27.3%	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
Underground Storage	Storage Leaks & Emissions	Fugitive	11,870	2,036	1,747	-14.2%	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It BP 22 - Pipe Fitting Specifications
	Compressor Emissions	Vented	5,360	5,360	1,703	-68.2%	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Blowdowns	Vented	16,324	16,324	7,102	-56.5%	BP 3 - Pressure Reduction Policy BP 4 - Project Scheduling Policy BP 5 - Methane Evacuation Procedure BP 6 - Methane Evacuation Work Order Policy BP 7 - Bundling Work Policy BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Emissions	Vented	N/A	86,681	78,244	-9.7%	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Leaks	Fugitive	10,574	75,957	6,505	-91.4%	BP 22 - Pipe Fitting Specifications BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Dehydrator Vent Emissions	Fugitive	6,761	13	8	-38.5%	N/A
Unusual Large Leaks	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 7 provides reported 2024 emissions and 2030 emission projections by measure. Detailed cost-effectiveness analysis is discussed in greater detail in each chapter, where applicable.

Table 7 - Emissions Level Estimate, Mscf, Year End

					Cost Effectiveness Part 5b $/MSCF			
Measure (Chapter No.)	**2024 Emission Reduction, Mscf**	**2024 % Reduc.**	**2030 Target Emission Reduction, Mscf**	**2030 % Reduc.**	**Standard Cost Effectiveness ($/Mscf)**	**Standard Cost Effectiveness including Cap & Trade Cost Benefits ($/Mscf)**	**Standard Cost Effectiveness Calculation including Social Cost of Methane Benefits ($/Mscf)**	**Notes**
1) Non-Emergency Gas Transmission Blowdown Reduction (Chapter 3)	267,685	16%	265,043	16%	$8	$7	($19)	Cost effectiveness is calculated by taking a two year average of the total volume of gas abated via cross compression, the total project cost of cross compression, and maintenance costs.
2) Gas Distribution Leak Surveys (Chapter 7) - Accelerated Leak Survey	not provided, this is dependent on the repairs				$52	$51	$25	Using 2025-2027 cost forecasts to calculate the incremental annual cost of transitioning from 5-year to 3-year cycle
3) Find It /Fix It (Chapter 11) - Distribution M&S	237,213	14%	264,901	16%	$274	$272	$248	Belowground Grade 3 leak repairs; assuming 1000 repairs and an average leak repair cost $10850/unit.
					$23	$21	($3)	Super Emitter program survey cost and repair cost at 5 scfh threshold; assuming 450 SE leaks repairs and an average leak repair cost $10850/unit.
4) Find It /Fix It (Chapter 11) - Meter Set Assemblies	50,363	3%	66,638	4%	$39	$38	$13	Meter set leak repairs assuming 35% reduction in emissions over 2024 baseline emissions.
5) Above Ground Leak Survey (Chapter 9) - Quarterly CARB Leak Surveys	68,541	4%	81,945	5%	$68	$66	$40	Forecasted emissions compared to the 2015 adjusted Baseline (to account for 10k to 1k ppm threshold decrease).
6) Damage Prevention (Chapter 14)	127,883	8%	166,807	10%	$82	$80	$54	Uses the 2015 baseline and comparing against forecasted emissions for both Transmission and Distribution Damages.
7) Other - includes Improvement in reporting practices, studies to better characterize emissions, remove/replace emitting devices, etc.	117,802	7%	75,301	5%				
TOTAL	**869,487**	**52%**	**920,635**	**55%**				

Each Chapter in this 2026 Compliance Plan describes a proposed Measure that consists of a Best Practice or a combination of Best Practices. Table 8 below provides the concordance for the Best Practices.

Table 8 – Table of Concordance for Best Practices

BP #	Chapters Addressing the BP, or Exempt
1	Chapter 1, Compliance Plan
2	Chapter 2, Methane GHG Policy
3 – 7	Chapter 3, Non-Emergency Gas Transmission Blowdown Reduction
8	Chapter 4, Emergency Procedures
9	Chapter 5, Recordkeeping
10 -14	Chapter 6, Gas Training
15 - 16	Chapter 7, Gas Distribution Leak Surveys
17 - 18	Chapter 8, Methane Detection
19	Chapter 9, Aboveground Leak Survey
20a	Chapter 10, Quantification and Geographic Tracking Chapter 15, Research, Development and Demonstration (RD&D) Projects
20b	Chapter 10, Quantification and Geographic Tracking
21	Chapter 11, Find It/Fix It
22	Chapter 12, Pipe Fitting Specifications
23	Chapter 3, Non-Emergency Blowdown Reduction Chapter 13, High-Bleed Pneumatic Device Replacements Chapter 15, RD&D Projects
24-26	Chapter 14, Damage Prevention

SECTION B. CHAPTERS DESCRIBING MEASURES

The chapters below describe each proposed Measure. PG&E created 15 Measures that address one or more Best Practices. Per CPUC guidance, each Chapter includes the following information across six parts.

Part 1. Evaluate the Current Practices Addressed in this Chapter

a) List the BP(s) addressed by this Chapter including their descriptive text
b) Assess the effectiveness of existing measures related to the BP(s) addressed in this chapter:
    1. What emission reduction do you attribute to this practice compared to the 2024 estimated reduction? What further reductions are expected?
    2. In terms of the utilities' own 2024 Compliance Plan cost effectiveness method, how does the actual cost effectiveness compare with the estimate?
    3. What is the cost effectiveness based on the definition in Part 5 below?

Part 2. Proposed New or Continuing Measure

Proposed Plan. Discuss the following, as applicable/appropriate.

1. Overlap with other statutory regulations? What part of the Measure is incremental beyond those regulations?
2. What technology is proposed to implement the measure and why?
3. Will the work require additional personnel and/or contract support? Provide details.
4. What changes to existing operations are required? How will those changes be implemented?
5. What changes to, or new procedures, are required?
   a) Timeline for Implementation including training on new procedures.
   b) Overlap with Other Measures in the Compliance Plan (if any)
   c) If the Measure will be addressed with R&D or pilot projects, reference them in the Chapter and describe them in the Appendix according to the R&D template.

Part 3. Abatement Estimates

This part will describe anticipated emissions reduction from the Measure as compared to the 2015 Baseline Emissions as established at the time the Plan is filed. Where known, state which emissions category, source, and classification in the Emissions Inventory is affected as a result of the proposed Measure. Provide supporting calculation methodology.

Part 4. Cost Estimates

This part will provide cost estimates of the proposed Measures to support Cost Effectiveness calculations as required in Decision D.19-08-020. List direct costs by major categories, such as tools, labor, vehicles, supervision, capital equipment, etc. Determine net cost by subtracting quantifiable benefits. Show loaded costs and calculate the average annual revenue requirement from the net loaded cost.

When possible, subtract avoided costs to the utility such as:

- Value of natural gas saved;
- Future reduced leak repair costs;
- Reduced gas lost to leakage;
- Shifting from emergency to planned work;
- Safety improvements;
- System reliability improvements; and
- Lower insurance costs.

Average Annual Revenue Requirement

Revenue requirement represents how the cost to the utility is passed on to customers, so it is the best indicator of costs for the purpose of evaluating ratepayer-funded activities. From comments cited in the Decision, page 26: The average annual revenue requirement (AARR) is generated by calculating the cumulative revenue requirement for activities that directly contribute to emissions

reductions. The activity costs used to calculate the revenue requirement include the fully loaded and escalated capital investment and associated operation and maintenance (O&M), including on-going O&M over the useful life of the related capital asset, if applicable. The cumulative revenue requirement is then divided by the total years of useful life to generate an average annual revenue requirement. This annual revenue requirement can be multiplied by the number of years in the Compliance Plan period. The annual revenue can then be compared to the emissions reductions for the same number of years.

Part 5. Cost Effectiveness/Benefits

Pursuant to Decision D.19-08-020, the cost effectiveness of the proposed measure is calculated by determining the ratio of net cost to the total emissions reduction, where net cost is the average annual revenue requirement, developed in Part 4, less all reasonably quantifiable benefits.

a) Determine the standard cost effectiveness as the ratio of net cost to volume of methane reduced, dollars per Mscf, for the same period.

$$\frac{AARR - Cost\ Benefits}{Emissions\ Reductions}$$

b) The same cost effectiveness calculation as a), with the cost benefit of avoided Cap-and-Trade costs included per D.19-08-020.

$$\frac{AARR - Cost\ Benefits - Avoided\ Cap\ \&\ Trade\ Cost}{Emissions\ Reductions}$$

c) The same cost effectiveness calculation as b), with the avoided social cost of methane included per D.19-08-020.

$$\frac{AARR - Cost\ Benefits - Avoided\ Cap\ \&\ Trade\ Cost - Social\ Cost\ of\ Methane}{Emissions\ Reductions}$$

The cost benefit values utilized in the 2026 Compliance Plan are as follows:

1. The cost benefit of reduced gas was calculated using the forecasted average annual Weighted Average Cost of Gas (WACOG) from the 2018 California Gas Report of $3.14/Mscf[1] and adjusting it for inflation to $4.06/Mscf (applying a 1.294 California

[1] Per CPUC guidance, PG&E uses the Weighted Average Cost of Gas (WACOG) published in the 2018 California Gas Report and adjusts it for inflation.

Consumer Price Index[2]).

2. The avoided Cap-and-Trade cost is $1.53/Mscf. This value was calculated by taking the February 2026 Auction Settlement Price of $27.94 per MTCO2e from the California-Quebec Joint Auction Settlement Prices and Results published by CARB and adjusting it using the conversion factor from D.15-10-032.
3. Per written guidance from the CPUC Safety Policy Division on November 21, 2023, a $25.94 social cost of methane was calculated using the D.19-08-020 estimate for 2020 of $21/Mscf and adjusting it for inflation using the 2025 annual California Consumer Price Index.

If choosing to combine Best Practices, this section will include the holistic costs of the measure which will provide a clearer picture of the costs of the proposal.
Cost effectiveness/benefits will be discussed at the measure level, where applicable.

Part 6. Supplemental Information/Documentation

If the Measure has any supporting documentation, it will be noted and listed in Section C.

[2] California Department of Industrial Relations, *California Consumer Price Index*, available at https://www.dir.ca.gov/OPRL/CPI/EntireCCPI.PDF. The adjustment factor is calculated as the ratio of the Annual 2025 CPI to the Annual 2018 CPI.

CHAPTER 1: COMPLIANCE PLAN

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E submits a biennial Compliance Plan as a separate attachment to the Gas Safety Plan. The Compliance Plan includes actions, measures, and procedures taken in the compliance period to comply with the 26 Best Practices set forth in the Decision Approving Natural Gas Leak Abatement Program Consistent with Senate Bill 1371 (D.17-06-015). PG&E maintains a biennial review cycle for the Compliance Plan and performs updates based on changes in regulatory guidance, operational practices, technology, and lessons learned.

a) Best Practice(s) Addressed by this Chapter

Best Practice 1 - Compliance Plan: Written Compliance Plan identifying the policies, programs, procedures, instructions, documents, etc. used to comply with the Final Decision in this Proceeding (R.15-01-008). Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB. Compliance Plans shall be signed by company officers certifying their company's compliance. Compliance Plans shall include copies of all policies and procedures related to their Compliance Plans. Compliance Plans shall be filed biennially (i.e., every other year) to evaluate best practices based on progress and effectiveness of Companies' natural gas leakage abatement and minimization of methane emissions.

b) Effectiveness

This measure establishes governance and reporting processes and does not directly reduce emissions.

Part 2. Proposed New or Continuing Measure

PG&E will continue to file the Compliance Plan biennially. PG&E tracks completion of compliance plans in an internal tracking system. This 2026 Compliance Plan is submitted as a separate attachment to the 2026 Gas Safety Plan. In addition, a management review (including officer certification) of this plan is performed prior to submission. The details of implementing each Best Practice can be found in the subsequent chapters.

Part 3. Abatement Estimates

Not applicable. This measure is specific to creating a process and not related to activities that reduce emissions.

Part 4. Cost Estimates and Average Revenue Requirement

No costs are associated with this measure.

Part 5. Cost Effectiveness/Benefits

Not applicable. This measure is the Compliance Plan reporting and emissions reduction cannot be calculated.

CHAPTER 2: METHANE GHG POLICY

Part 1. Evaluate the Current Practices addressed in this Chapter

Addressing climate change is integral to PG&E's mission to provide safe, reliable, affordable, and clean energy to its customers. Since 2006, PG&E has maintained a Climate Change Principles Policy that recognizes the challenges posed by climate change, as well as PG&E's commitment to reduce its greenhouse gas emissions and help its customers do the same. On October 27, 2022, PG&E updated its existing Climate Change Principles Policy (ENV-03) to include a specific reference to reducing emissions of methane, a potent GHG released from the operation of natural gas infrastructure, by implementing SB 1371 and SB 1383, which address leak abatement and short-lived climate pollutants, respectively.

a) Best Practice(s) Addressed by this Chapter

Best Practice 2 – Methane GHG Policy: Written company policy stating that methane is a potent GHG whose emissions to the atmosphere must be minimized. Include reference to SB 1371 and SB 1383. Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB, as part of Compliance Plan filing.

b) Effectiveness

This measure requires the implementation of a company policy addressing methane emissions. While it does not directly reduce emissions, it ensures alignment with regulatory requirements and supports operational decision-making.

Part 2. Proposed New or Continuing Measure

No additional changes are needed for the 2026 Compliance Plan period.

Part 3. Abatement Estimates

Not applicable. This measure is policy-based and does not result in quantifiable emission reductions.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Compliance with Best Practice 2 is complete. No additional funding is required for the 2026 Compliance Plan period.

Part 5. Cost Effectiveness/Benefits

Not applicable. This measure is a policy-based and does not directly result in quantifiable emission reductions.

CHAPTER 3: NON-EMERGENCY GAS TRANSMISSION BLOWDOWN REDUCTION

Part 1. Evaluate the Current Practices addressed in this Chapter

To meet sustainability goals and comply with SB 1371 and SB 1383, PG&E developed a standard (TD-5601S) and procedure (TD-5601P-01) to reduce methane emissions during non-emergency gas transmission blowdowns while maintaining the safety and reliability of PG&E's gas system. This standard and procedure provide direction to:

- Assess planned gas transmission system construction projects with sufficient lead time to incorporate emission reduction strategies, including clearance sharing, drafting, cross compressing, flaring, and use of Pressure Control Fittings (PCFs) to reduce the volume of the isolation
- Reduce pressures of transmission isolation areas to the lowest operationally feasible levels to minimize the venting of methane
- Document significant factors considered in methane abatement decisions for all planned transmission projects
- Employ methane reduction strategies for transmission system leak repairs
- Calculate expected emissions and reduction volumes for scheduled projects
- Complete a post-blowdown evaluation and analysis after blowdown events that utilized a GHG mitigation strategy

PG&E provides training to Transmission Gas Operations' employees to ensure awareness of the following:

- PG&E's commitments to reduce methane emissions as much as feasible during non-emergency gas transmission blowdowns
- The roles and responsibilities established under TD-5600S, *Tracking Greenhouse Gas Emissions,* and TD-5601S, *Greenhouse Gas Emission Reduction*
- The objectives and requirements of the Greenhouse Gas Feasibility Assessment

Refresher training has been delivered to transmission project managers and project engineers as they both play critical roles in evaluating the feasibility of incorporating methane emission reduction strategies into projects that require gas blowdowns.

a) Best Practice(s) Addressed by this Chapter

Best Practice 3 – Pressure Reduction Policy: Written company policy stating that pressure reduction to the lowest operationally feasible level in order to minimize methane emissions is required before non-emergency venting of high pressure distribution (above 60 psig), transmission and underground storage infrastructure consistent with safe operations and considering alternative potential sources of supply to reliably serve customers.

Best Practice 4 – Project Scheduling Policy: Written company policy stating that any high pressure distribution (above 60 psig), transmission or underground storage infrastructure project

that requires evacuating methane will build time into the project schedule to minimize methane emissions to the atmosphere consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Projected schedules of transmission or underground storage infrastructure work, requiring methane evacuation, shall also be submitted to facilitate audits, with line venting schedule updates to be determined.

Best Practice 5 – Methane Evacuation Procedure: Written company procedures implementing the BPs approved for use to evacuate methane for nonemergency venting of high-pressure distribution (above 60 psig), transmission or underground storage infrastructure and how to use them consistent with safe operations and considering alternative potential sources of supply to reliably serve customers.

Best Practice 6 – Methane Evacuation Work Order Policy: Written company policy that requires that for any high pressure distribution (above 60 psig), transmission or underground storage infrastructure projects requiring evacuating methane, Work Planners shall clearly delineate, in procedural documents, such as work orders used in the field, the steps required to safely and efficiently reduce the pressure in the lines, prior to lines being vented, considering alternative potential sources of supply to reliably serve customers.

Best Practice 7 – Bundling Work Policy: Written company policy requiring bundling of work, whenever practicable, to prevent multiple venting of the same piping consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Company policy shall define situations where work bundling is not practicable.

Best Practice 23 – Minimize Emissions from Operations, Maintenance and Other Activities: Utilities shall minimize emissions from operations, maintenance, and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e., no bleed) or vents significantly less natural gas (i.e., low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

b) Effectiveness

The Blowdown Emission Reduction standard and its associated procedure meet the intent of Best Practices 3 through 7. The feasibility and effectiveness of methane abatement depend on the project scope and the type of transmission asset involved. Integrity management work, such as valve replacement and hydrotest, generally provide greater opportunities for emissions reduction than in-line inspections which require only limited blowdowns. Additionally, large backbone transmission pipelines present better abatement potential than local transmission pipelines due to their larger volumes and operating pressure. PG&E targets an annual abatement of 90% of potential gas releases from backbone pipeline clearances, and 75% of potential gas releases from local transmission pipeline clearances.

PG&E will continue to utilize the Blowdown Emission Reduction standard for the 2026 Compliance Plan period and updates may be made pending the results of the ongoing post-blowdown evaluations. The post-blowdown evaluation includes: methane emission reduction

strategy used, total volume of gas released, total volume of gas abated, a comparison of the planned ending pressure prior to blowdown and the actual ending pressure following the blowdown, and if the actual ending pressure is 10% higher than the planned ending pressure, the reason for the variance.

Part 2. Proposed New or Continuing Measure

PG&E will continue to implement methane emission reduction strategies in accordance with standard TD-5601S. Specifically, PG&E will continue to:

- Utilize 8 multi-stage/boost compressors to reduce the amount of gas released during clearances with the potential to emit more than 1 MMscf of gas. This approach ensures that projects with the largest GHG emission potential are appropriately targeted. These multi-stage/boost compressors are designed to accommodate larger pressure differentials, enabling drawdown to very low pipeline pressures.

- Utilize PG&E-owned enclosed combustion devices and thermal oxidizers, which allow PG&E to handle large pipeline volumes and offer improved combustion efficiency compared to traditional flaring technologies. PG&E also rents additional enclosed combustion units to improve throughput for high-pressure, large diameter systems. PG&E continues to document the volume of gas vented and combusted from gas odor fade operations and special in-line inspection activities.

To further advance Best Practice 23, PG&E intends to implement the following initiatives in 2026 to continue reducing methane emissions associated with planned transmission blowdowns:

1. Update the guidelines for recommended methane abatement strategies for clearances at Transmission M&R Stations, Compressor Stations, and Underground Storage Facilities.

2. Continue to evaluate the use of degassing technology on ILI tool load & unloading blowdowns to determine if a technology can be expanded to further reduce methane emissions from other activities, such as smaller volume local transmission projects and station maintenance.

3. Update project clearance procedures to require a GHG abatement assessment for scheduled transmission clearances that expect to release more than 500 Mscf of gas to the atmosphere. This action will increase the amount of methane abatement activities, thus reducing emissions.

4. Review and analyze pipeline and station projects that utilize pressure control fitting or hot-taps. The purpose of this review is to determine the amount of gas abated by reducing the isolation window of the clearance.

Part 3. Abatement Estimates

In 2024, PG&E abated 90% of the total gas volume across all transmission and storage clearance activities (Table 9). Current estimates for 2025 indicate that PG&E will have abated 80% of the total gas volume across all transmission and storage clearance activities (Table 10). PG&E diverted a total of 686 MMscf of methane from being blown to atmosphere between 2024 and 2025. Relative to the 2015 baseline, 2024 transmission and storage blowdown emissions have decreased 76%.

Table 9 - 2024 Transmission Pipeline, M&R Station, Compressor Station, and Underground Storage Activities

Pipeline Activity Type	Total Gas Volume (Mscf)
Drafting	78,650
Cross-Compression	340,573
Combustion	2,871
Clearance Sharing	Not calculated
Total Gas Abatement	422,093
Blowdown	47,497
Percent Abatement	**90%**

Table 10 - 2025 Transmission Pipeline, M&R Station, Compressor Station, and Underground Storage Activities

Pipeline Activity Type	Total Gas Volume (Mscf)
Drafting	18,757
Cross-Compression	243,664
Combustion	1,797
Clearance Sharing	Not calculated
Total Gas Abatement	264,196
Blowdown	67,403
Percent Abatement	**80%**

Part 4. Cost Estimates and Average Annual Revenue Requirement

The primary cost associated with this measure is the cost of the cross-compression program. The proposed actions for this measure during the 2026 Compliance Plan period are forecasted through PG&E's 2027 GRC rate case and no additional funding is being requested. Most of the costs associated with the cross-compression program are captured in the appropriate MAT code based on the clearance scope of work. The remaining costs associated with the cross-compression program are reflected in the LNG/CNG MAT codes.

Part 5. Cost Effectiveness/Benefits

Compared to the 2015 Baseline, PG&E reduced blowdown methane emissions by 268 MMscf in 2024. The average annualized cost of the program is estimated at $3.4 million. Accounting for the value of gas saved from emissions reduction leads to a standard cost effectiveness value of $8/Mscf. Including the cost benefits from Cap-and-Trade and the social cost of methane, the cost effectiveness becomes -$19/Mscf.

CHAPTER 4: EMERGENCY PROCEDURES

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E performs regular maintenance across its gas system and follows established procedures to minimize and prevent uncontrolled methane releases. PG&E's Gas Emergency Response Plan (GERP) addresses how the company responds to emergencies, including loss of containment from the gas system or storage facilities. While PG&E employs multiple layers of protection to prevent the loss of containment of natural gas, PG&E is prepared to respond when releases do occur. PG&E reviews and updates the GERP on an annual basis to ensure it remains current and effective.

a) Best Practice(s) Addressed by this Chapter

Best Practice 8 – Company Emergency Procedures: Written company emergency procedures which describe the actions company staff will take to prevent, minimize and/or stop the uncontrolled release of methane from the gas system or storage facility consistent with safe operations and considering alternative potential sources of supply to reliably serve customers.

b) Effectiveness

Cost effectiveness was not calculated in the 2026 Compliance Plan. Emissions reductions are directly associated with the length of time a leak remains open. An improvement in the average gas shut in time will reduce the amount of time the leak stays open and thus reduce emissions.

Part 2. Proposed New or Continuing Measure

PG&E will continue to utilize its GERP to comply with Best Practice 8. There are no additional actions being proposed.

Part 3. Abatement Estimates

Emissions reductions cannot be directly measured through implementation of PG&E's GERP. However, improvements in shut-in the gas performance will reduce the amount of time that a leak, resulting from emergency situations, remain open. Emissions reduction from PG&E's Damage Prevention programs, which address dig-ins, are reported annually through the Natural Gas Leakage Report for the Leak Abatement OIR.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Compliance with Best Practice 8 is complete, and no additional actions are required for the 2026 Compliance Plan period.

Part 5. Cost Effectiveness/Benefits

Not applicable. This measure is the review and update of PG&E's emergency procedures and emissions reduction cannot be calculated. There are also no incremental costs associated with the review and update of PG&E's GERP.

CHAPTER 5: RECORDKEEPING

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E's records management is governed by PG&E Corporation Standard GOV-7101S, Enterprise Information and Records Management Standard. This standard establishes requirements, roles and responsibilities for governing and managing Data, Information, and Records of PG&E corporation and its subsidiaries, including Pacific Gas and Electric Company (together, PG&E). This standard applies to Data, Information, and Records created, modified, utilized, maintained, stored, archived, retrieved, transmitted, and disposed of during the course of PG&E business, regardless of format. The standard also provides the retention schedule for all PG&E records at the highest level (record category).

Currently, the SB 1371 Annual Emissions Inventory Reports are "Regulatory Records" as they are filed annually pursuant to the Leak Abatement OIR proceeding. To comply with this Best Practice, the retention code is RSC75 Regulatory Filings – CPUC Major. Therefore, these records will be retained for the life of the Company.

a) Best Practice(s) Addressed by this Chapter

Best Practice 9 – Recordkeeping: Written Company Policy directing the gas business unit to maintain records of all SB 1371 Annual Emissions Inventory Report methane emissions and leaks, including the calculations, data and assumptions used to derive the volume of methane released. Records are to be maintained in accordance with General Order (GO)112-F and succeeding revisions, and 49 CFR 192. Currently, the record retention period in GO 112-F is at least 75 years for the transmission system. 49 CFR 192.1011 requires a record retention period of at least 10 years for the distribution system.

b) Effectiveness

This measure addresses recordkeeping and does not directly reduce emissions.

Part 2. Proposed New or Continuing Measure

Compliance with Best Practice 9 is complete, and no additional actions are required for the 2026 Compliance Plan period.

Part 3. Abatement Estimates

Not applicable. This measure is specific to creating a process and not related to activities that reduce emissions.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Compliance with Best Practice 9 is complete, and no additional actions are required.

Part 5. Cost Effectiveness/Benefits

Not applicable. This measure relates to recordkeeping and emissions reduction cannot be calculated.

CHAPTER 6: GAS TRAINING

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E's work requires well-trained personnel to perform work activities in the correct way. As a result, the Company invests in recruiting and retaining skilled employees, provides ongoing development and training, and maintains supportive controls for employee and contractor work. PG&E currently utilizes a talent requisition site to provide guidance on hiring employees. This process allows leaders to work with Human Resources and Labor Relations (as applicable) to create job openings, define the classification of the job, and look for candidates with existing qualifications and/or prior experience. This process also provides leaders with the support needed to make updates to existing classifications. Furthermore, gas employees whose work can affect methane emissions and leak abatement are required to take the requisite training as described below.

Existing Gas Training Practices

PG&E's Human Resource Department develops technical training materials required to maintain a skilled, safe, and qualified workforce. The Gas Training Curriculum Development Program focuses on developing task analysis-based curriculum that reflects current standards, procedures, and regulations, properly introducing and reinforcing safety requirements.

The drivers for curriculum development include:

a. Regulatory requirement-driven updates to work procedures
b. Facilitating knowledge transfer from employees exiting the workforce to those entering
c. Emergent equipment, technologies and processes
d. Changes to work standards and procedures

The scope of the curriculum developed is informed by external obligations and business needs. Curriculum development priorities are set through the Gas Training Alignment Committee (GTAC) process that delivers accountability, transparency, and oversight, in conjunction with the supporting guidance documents and qualifications that align to the Gas Operations Risk Register and the Corrective Action Program.

The following Operator Qualifications (OQ) and courses, among others, support PG&E's efforts to reduce greenhouse gas emissions and these Best Practices.

Operator Qualifications

- OQ-0805 Aerial Leak Survey by Drone
- OQ-0901 Conduct Survey (Using Company Approved Instruments)
- OQ-0902 Leak Investigation (Using Company Approved Instruments)
- OQ-0903 Field Services Leak Investigation/Leak Grading (Using Company Approved Instruments)
- OQ-0911 Conduct Mobile Leak Survey (Picarro)

- OQ-0912 Conduct Mobile Leak Survey (Using Company Approved Instruments, i.e. OMD and DP-IR Mobile)

Training

- **Gas-0207 Leak Survey Detection & Grading:** The course presents an overview of the leak survey process and reviews the current gas standards, guidelines, and bulletins that apply to the leak survey. The student will inspect, calibrate, and perform minor maintenance on various leak survey instruments. They will perform leak survey, grading, and complete associated documentation per established standards, guidelines, and bulletins.
- **Gas-0214 Leak Survey Refresher:** The course provides "refresher" instruction on conducting a leak survey, and a review of the most currently updated leak survey procedures. This training is designed to prepare employees to conduct a leak survey in alignment with all PG&E standards and procedures.
- **GAS-0306 Leak Investigation & Pinpointing:** The course trains PG&E employees to follow a systematic approach for investigating and pinpointing gas leaks in accordance with work procedure TD-5100P-02 Subsurface Leak Investigation and Pinpointing for Repair.
- **GAS-9642 Mobile Leak Survey:** Leak surveyors learn how to safely operate, test, and maintain an Optical Methane Detector device, as well as the DP-IR mobile vehicle. In addition, they learn how to plan their route, prepare, install, inspect, maintain, and perform a leak survey with a Detecto-Pak Mobile Unit and complete the end of use steps for the unit.
- **Gas Emergency Response Plan (GERP) Training**: PG&E's Gas Emergency Preparedness training consists of three GERP courses as follows:
    - **Gas-9122 GERP Awareness**: The course provides general awareness-level information for the GERP and is intended for all Gas employees (except Field Responders and Emergency Center staff) and shared services agencies that support Gas Operations. This course also defines the role of PG&E field responders as well as the necessary activities to activate and maintain the Emergency Response Process.
    - **Gas-9123 GERP Emergency Center (Instructor Led Training)**: The course provides training on the changes to the GERP, as well as the participants' role in responding to or supporting a gas emergency using the Incident Command System.

These training courses are updated and assigned to designated employees on an annual basis.

Gas Safety Academy

The Gas Safety Academy in Winters, California opened in 2017. This facility has become the primary training center for employees learning to operate and maintain every aspect of PG&E's natural gas infrastructure. It features the latest in training technologies, including heavy equipment simulators, virtual learning resources, a model neighborhood for emergency response and leak detection practices, and educational programs on industry-leading safety protocols.

The Gas Safety Academy consists of two components: the Learning Center and the Utility Village. The Learning Center is the primary technical training center that includes classrooms, labs, Measurement & Control (M&C) tech center (e.g., the Indoor Flow Lab where compressed air is used to simulate natural gas flow), and a gas service representative (GSR) area, where GSRs are trained in customer service activities including meters, leak detection and service inspections. The Utility Village is a small-scale replica of a residential neighborhood used to train field service representatives on customer interface, leak detection, location and marking of existing pipelines, and emergency response scenario training.

To support safe and emissions-free training, the Gas Safety Academy utilizes compressed air in multiple facilities, including the Gas Pipeline Operations & Maintenance flow lab, the gas chromatography room, and the Field Services lab for service mechanic training. Utilization of compressed air versus natural gas provides a zero-gas emission training environment and allows students to safely and quickly perform routine maintenance on simulated distribution and transmission regulation equipment. In addition, allowing students to train on and perform rotary meter operations—such as differential testing, flange and gasket installation and removal, and full meter removals—provides comprehensive hands-on training without requiring the release of natural gas to the atmosphere.

For instruction involving operations and maintenance of distribution and transmission regulation stations and associated gas measurement equipment (e.g., ERX, SCADA, Totalflow, Becker controllers), students and lab operators are able to remove components on the gas system and conduct inspections similar to those performed in the field without the need to exhaust natural gas to the atmosphere.

An additional benefit of the flow lab is the ability to evaluate new technology or gas regulation components that require testing and "proof of concept" validation prior to field deployment. The use of compressed air allows for unlimited fill and evacuation cycles during testing, a capability that would be impractical using natural gas. As a result, the volume of natural gas emissions avoided through the consistent use of compressed air across training and testing activities is substantial.

a) Best Practice(s) Addressed by this Chapter

Best Practice 10 - Minimize Uncontrolled Natural Gas Emissions Training: Training to ensure that personnel know how to use company emergency procedures which describe the actions staff shall take to prevent, minimize and/or stop the uncontrolled release of natural gas from the gas system or storage facility. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's General Rate Case (GRC) and/or Collective Bargaining Unit (CBU) processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.

Best Practice 11 - Methane Emissions Minimization Policies Training: Ensure that training programs educate workers as to why it is necessary to minimize methane emissions and abate natural gas leaks. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or Collective Bargaining Unit (CBC) processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.

Best Practice 12 - Knowledge Continuity Training Programs: Knowledge Continuity (Transfer) Training Programs to ensure knowledge continuity for new methane emissions reductions best practices as workers, including contractors, leave and new workers are hired. Knowledge continuity training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.

Best Practice 13 - Performance Focused Training Programs: Create and implement training programs to instruct workers, including contractors, on how to perform the BPs chosen, efficiently and safely. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.

Best Practice 14 - Job Classifications: Create new formal job classifications for apprentices, journeyman, specialists, etc., where needed to address new methane emissions minimization and leak abatement best practices, and filed as part of the Compliance Plan filing, to be approved by the CPUC, in consultation with CARB.

b) Effectiveness

Cost effectiveness is not applicable. There are no emissions reductions anticipated from Gas Operations training that support the Best Practices mentioned above.

Part 2. Proposed New or Continuing Measure

PG&E will continue using its existing Gas Operations training plan and curriculum development/updates to support these Best Practices. No additional or incremental work is proposed for the 2026 Compliance Plan period.

PG&E will utilize its historic training efforts to address any required updates within existing job classifications. Current job classifications adequately encompass the necessary skills and

training necessary for employees whose work may affect methane emissions and leak abatement. At this time, PG&E does not anticipate the creation of new job classifications related to methane emissions minimization or leak abatement in 2026 or 2027. Accordingly, compliance with Best Practice 14 is complete.

Part 3. Abatement Estimates

Not applicable. Emissions reductions cannot be measured from training classes.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Gas Operations training does not directly contribute to emissions reductions. Annual revenue requirements for all planned gas training (including those listed above) are approximately $5.96 million for 2026. For 2027, the Gas Operations training forecasted expenditure is approximately $6.18 million[3]. There is no incremental funding requested to comply with these Best Practices.

Part 5. Cost Effectiveness/Benefits

Not applicable. This measure is the implementation of training and programs through Gas Operations Training and methane emissions reductions cannot be calculated.

[3] 2027 GRC Gas Training forecast. This forecast is included in Exhibit 7, Chapter 1 testimony and workpapers as part of the Academy forecast (MWC OS)

CHAPTER 7: GAS DISTRIBUTION LEAK SURVEYS

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E performs gas distribution leak surveys on a three-year leak survey cycle, exceeding the five-year requirement under GO 112-F. The gas distribution leak surveys are conducted via traditional foot surveys and complemented by Advanced Mobile Leak Detection (AMLD) for an annual Super Emitter (SE) survey.

PG&E also conducts special leak surveys on selected vintage pipes on distribution assets. The material focus of the special leak survey is pre-1940 steel and pre-1975 plastic vintages. The vintage pipe leak survey has been integrated into the DIMP leak risk review process.

In 2025, PG&E updated the definition of a leak indication from five ppm (parts per million) to 200 ppm outside of five feet of a structure and/or ten feet wall to wall. The reason for the update was to be consistent with benchmarking and internal leak cancellation data.

a) Best Practice(s) Addressed by this Chapter

Best Practice 15 – Gas Distribution Leak Survey: Utilities should conduct leak surveys of the gas distribution system every 3 years, not to exceed 39 months, in areas where GO 112-F, or its successors, requires surveying every 5 years. In lieu of a system-wide three-year leak survey cycle, utilities may propose and justify in their Compliance Plan filings, subject to Commission approval, a risk-assessment based, more cost-effective methodology for conducting gas distribution pipeline leak surveys at a less frequent interval. However, utilities shall always meet the minimum requirements of GO 112-F, and its successors.

Best Practice 16 – Special Leak Surveys: Utilities shall conduct special leak surveys, possibly at a more frequent interval than required by GO 112-F (or its successors) or BP 15, for specific areas of their transmission and distribution pipeline systems with known risks for natural gas leakage. Special leak surveys may focus on specific pipeline materials known to be susceptible to leaks or other known pipeline integrity risks, such as geological conditions. Special leak surveys shall be coordinated with transmission and distribution integrity management programs (TIMP/DIMP) and other utility safety programs. Utilities shall file in their Compliance Plan proposed special leak surveys for known risks and proposed methodologies for identifying additional special leak surveys based on risk assessments (including predictive and/or historical trends analysis). As surveys are conducted over time, utilities shall report as part of their Compliance Plans, details about leakage trends. Predictive analysis may be defined differently for differing companies based on company size and trends.

Best Practice 17 – Enhanced Methane Detection: Utilities shall utilize enhanced methane detection practices (e.g., mobile methane detection and/or aerial leak detection) including gas speciation technologies.

b) Effectiveness

The three-year leak survey cycle enables faster leak detection and repair of distribution leaks, reducing emissions by reducing the number of days open for a leak.

The Super Emitter survey accelerates detection and repair of large leaks, further reducing emissions from the gas distribution system.

The annual DIMP survey allows for risk-focused inspection of pipeline segments known to be more susceptible to leaks and providing earlier opportunities for mitigation.

Part 2. Proposed New or Continuing Measure

PG&E will continue to perform its compliance leak survey on a three-year cycle. PG&E will also maintain its annual Super Emitter survey, leveraging AMLD capabilities to identify large leaks across the distribution system.

Furthermore, PG&E will continue to perform special leak surveys targeting vintage materials and higher-risk pipeline segments. PG&E will continue to integrate the SE field-of-view coverage analysis into vintage pipeline foot-survey planning to focus resources on segments not covered by the super emitter survey (e.g., ~46% of vintage segments were covered by AMLD in 2025)

PG&E operationalized the SE field-of-view coverage informed planning for special leak survey in 2023 and plans to continue this measure during the 2026 Compliance Plan period.

These measures will continue during the 2026-2027 Compliance Plan period with no major modification planned.

Part 3. Abatement Estimates

Compliance Survey

The emission reduction calculation for the Compliance Survey is based on moving from a 5-year to 3-year survey cycle. The calculation assumes that the leaks are repaired in the year they are found (no backlog) and that the leak growth in plats[4] follows a linear model. The long-term emissions reduction (steady state) is 33%. This 33% reduction was applied to the 2016 emissions for found and unknown leaks, as 2016 represents the most recent year in which distribution leak surveys were conducted on a five-year survey cycle. Applying the 33% reduction, the expected annual reduction in emissions volume is 138,700 Mscf.

Super Emitter Program

The super emitter survey contributes significantly to methane emissions reduction by accelerating the identification of large leaks in the distribution system. These reductions are reflected in chapter 11 (Find it /Fix it).

Part 4. Cost Estimates and Average Annual Revenue Requirement

[4] A Plat is a gas-distribution mapping unit containing information about the gas distribution system

The 2026-2027 average annual revenue requirement for Gas Distribution Compliance leak survey, Super Emitter Program, and Annual DIMP Leak Survey are as follows:

Compliance (Traditional Leak Survey)

PG&E forecasts approximately $19.9 million in 2026 and $19.7 million in 2027 to complete the compliance leak survey on a 3-year cycle covering approximately 1.5 million and 1.4 million services and associated mains, respectively. The incremental annual cost of transitioning from 5-year to 3-year cycle is $7.8 million, on top of approximately $11.7 million per year for the 5-year cycle.

Super Emitter Program

PG&E forecasts approximately $2.0 million in 2026 and approximately $2.0 million in 2027 to complete the super emitter survey.

Annual DIMP Leak Survey

PG&E forecasts approximately $0.9 million in 2026 and $0.9 million in 2027 to perform annual DIMP Leak surveys. The DIMP Leak Survey Program is a targeted risk mitigation program that goes beyond and is separate from the leak surveys required by code. Survey areas are identified through the DIMP risk review process, emergent issues such as incidents, and compliance concerns.

No incremental funding is required to perform the work beyond what's approved through the GRC process.

Part 5. Cost Effectiveness/Benefits

The cost effectiveness calculation is based on the cost difference between conducting leak surveys on a 3-year cycle versus a 5-year cycle (less the value of gas saved), divided by the expected emissions reduction of 138,700 Mscf. This calculation equals a standard cost effectiveness of approximately $52/Mscf. Please note that this cost does not include leak repair costs. As the survey cycle reaches steady state, leaks discovery rate is expected to stabilize, and no incremental repair costs are expected. When avoided Cap-and-Trade and social cost of methane are included, the net cost-effectiveness of the leak survey is $25/Mscf.

CHAPTER 8: METHANE DETECTION

Part 1. Evaluate the Current Practices Addressed in this Chapter

During the 2024 Compliance Plan period, PG&E continued to utilize the Picarro Surveyor for advanced mobile leak detection and expanded its super emitter program to further reduce methane emissions. PG&E also continued to use aerial technologies and leveraged additional R&D efforts to enhance existing capabilities and identify new detection technologies.

As part of these R&D efforts, PG&E developed and deployed new solutions including:

- The implementation of a helicopter detection and quantification technology for transmission leak survey
- The implementation of a new drone sensor for leak detection on hard-to-reach transmission lines
- The implementation of continuous leak monitoring at 1 gas storage facility
- Piloting of continuous monitoring at 10 transmission metering and regulating (M&R) stations
- Exploration of satellite leak detection technologies

a) Best Practice(s) Addressed by this Chapter

Best Practice 17 – Enhanced Methane Detection: Utilities shall utilize enhanced methane detection practices (e.g., mobile methane detection and/or aerial leak detection) including gas speciation technologies.

Best Practice 18 - Stationary Methane Detectors: Utilities shall utilize Stationary Methane Detectors for early detection of leaks. Locations include Compressor Stations, Terminals, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R aboveground and pressures above 300 psig only). Methane detector technology should be capable of transferring leak data to a central database, if appropriate for the installation location.

b) Effectiveness

This measure does not reduce emissions but rather enables PG&E to detect leaks faster. Identifying a large number of small leaks from the gas system leads to methane emission reductions that can be represented by the adjustment of leak-based emissions factors for the utilities implementing this measure.

Cost effectiveness was not calculated because the detection of leaks does not provide a direct impact to emission reduction.

Part 2. Proposed New or Continuing Measure

PG&E will continue to implement the current actions related to enhanced methane detection to comply with Best Practice 15. This action uses and explores a broad range of technologies.

Refer to Chapter 15 – RD&D projects for a list of technologies PG&E is exploring.

Part 3. Abatement Estimates

An abatement estimate cannot be calculated for the advancement of leak detection technologies.

Part 4. Cost Estimates and Average Annual Revenue Requirement

The actions contained in this measure are funded through PG&E's RD&D funding mechanisms and in some cases, funding is cost-shared by other utilities through research consortium. Refer to Chapter 15 – RD&D projects for the cost estimate and average annual revenue requirement.

Part 5. Cost Effectiveness/Benefits

Refer to Chapter 15 – RD&D projects for the cost effectiveness and benefits.

CHAPTER 9: ABOVEGROUND LEAK SURVEY

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E conducts leak surveys at aboveground facilities in compliance with CARB Oil and Gas Rule and GO 112-F, meeting the minimum annual requirement of Best Practice 19. Current practices include:

- Quarterly leak surveys at compressor stations and underground storage facilities, as required by CARB Oil and Gas Rule.
- Semi-annual leak surveys at city gates and metering & regulating (M&R) stations consistent with GO 112-F

These leak surveys enable leak repairs to be conducted at a faster rate than the annual leak survey cycle. In 2020, the leak threshold for CARB O&G facilities was reduced from 10k to 1k ppm. This change significantly increased the number of reportable leaks, resulting in a 264% increase in reported emissions, compared against 2019.

a) Best Practice(s) Addressed by this Chapter

Best Practice 19 – Aboveground Leak Surveys: Utilities shall conduct frequent leak surveys and data collection at aboveground transmission and high-pressure distribution (above 60 psig) facilities including Compressor Stations, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R aboveground and pressures above 300 psig only). At a minimum, aboveground leak surveys and data collection must be conducted on an annual basis for compressor stations and gas storage facilities.

b) Effectiveness

The mandatory quarterly leak surveys enabled PG&E to detect and repair leaks at a faster rate, reducing fugitive emissions from aboveground facilities. PG&E reported a 68 MMscf decrease in fugitive emissions (between the 2015 adjusted baseline and 2024) from leaks at its compressor stations and underground storage facilities.

Part 2. Proposed New or Continuing Measure

PG&E will continue its existing aboveground leak survey program as required by regulations, while evaluating continuous monitoring technology that can quantify emissions from storage facilities (see Chapter 15: RD&D Projects) and exploring new and advanced technologies to detect aboveground leaks, including aerial leak detection.

No additional actions are proposed to comply with this Best Practice during the 2026 Compliance Plan period.

Part 3. Abatement Estimates

This emissions reduction is projected to remain the same for 2026-2027 period as there is no incremental work planned.

Part 4. Cost Estimates and Average Annual Revenue Requirement

PG&E's forecasted annual revenue requirement for the CARB Leak Survey Program, the CARB Leak Repair Program, and Ground Leak Survey Program during the 2026-2027 Compliance Plan period is as follows:

2026
CARB Leak Survey: $4.0 million
CARB Leak Repair: $0.6 million
Ground Leak Survey: $0.7 million

2027
CARB Leak Survey: $4.3 million
CARB Leak Repair: $0.9 million
Ground Leak Survey: $0.7 million

No incremental funding is required to perform the work beyond what's approved through the GRC process.

Part 5. Cost Effectiveness/Benefits

The average annual revenue requirement for the quarterly CARB leak survey and repair program is $4.9 million. The net annual cost, which includes cost savings of gas not emitted due to the repairs, is $4.7 million. Dividing the net annual cost by the emissions reduction, the standard cost effectiveness is approximately $68/Mscf. Including the benefits of Cap-and-Trade and the social cost of methane, the cost effectiveness improves to $40/Mscf.

The cost effectiveness/benefit analysis was not performed on aboveground transmission pipelines since the emissions are calculated using a mile-based approach.

CHAPTER 10: QUANTIFICATION AND GEOGRAPHIC TRACKING

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E addresses Best Practice 20a by leveraging advanced mobile technology through the SE program to quantify emissions as detailed in Chapters 7 and 11.

To meet Best Practice 20b PG&E developed a centralized, searchable map that displays gas-related emissions data collected through its system-wide gas emissions survey process over the past three years. The map is updated annually after the June Natural Gas Leak Abatement OIR report filing. The data is tracked and analyzed to monitor year-over-year reductions in methane emissions across PG&E's service area.

a) Best Practice(s) Addressed by this Chapter

Best Practice 20a – Quantification & Geographic Tracking. This best practice states the following: Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with CPUC and CARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks for the purpose of tracking emissions reductions.

Best Practice 20b – Geographic Tracking. This best practice states the following: Utilities shall develop methodologies for improved geographic tracking and evaluation of leaks from the gas systems. Utilities shall work together, with CPUC and CARB staff, to come to agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist demonstrations of actual emissions reductions. Leak detection technology should be capable of transferring leak data to a central database in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

b) Effectiveness

No reductions in emissions are directly associated with this measure. This measure is specific to quantification and geographically tracking leaks and is not related to activities that reduce emissions.

Part 2. Proposed New or Continuing Measure

PG&E proposes to continue the RD&D projects and use the results to refine/establish emission factors and develop new techniques for leak quantification. Refer to Chapter 15 – RD&D projects for a list of projects PG&E is performing.

Finally, as stated in Part 1 above, PG&E has published a publicly available geographic map that displays emission information by zip code. PG&E plans to update the data after annual emission reporting is approved.

Part 3. Abatement Estimates

Calculating abatement is not applicable as this measure aims to quantify and geographically track leaks rather than implementing direct emissions reduction activities

Part 4. Cost Estimates and Average Annual Revenue Requirement

The actions contained in this measure are funded through PG&E's RD&D funding mechanisms and in some cases, funding is cost-shared by other utilities through research consortium. Refer to Chapter 15 – RD&D projects for the cost estimate and average annual revenue requirement. No incremental funding is required to complete the forecasted work.

Part 5. Cost Effectiveness/Benefits

This measure evaluates technologies to enhance PG&E's ability to quantify leaks; therefore, emissions reduction cannot be calculated based on this measure.

CHAPTER 11: FIND IT/FIX IT

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E performs compliance leak surveys on approximately one-third of its distribution system annually ensuring full coverage every 3 years. In addition, PG&E conducts annual Super Emitter (SE) survey using AMLD technology to identify and prioritize the largest leaks for repair. PG&E has progressively lowered the SE detection threshold from 10 scfh to 7 scfh (2023), 6 scfh (2024), 5 scfh (2025), and in some targeted cases used lower thresholds to accelerate identification and repair of high-emitting leaks.

PG&E continues to repair all Grade 1 and Grade 2 leaks in accordance with regulatory requirements. As mandated by the Commission's General Order 112-F, all Grade 1 leaks are repaired immediately, while Grade 2 leaks are repaired within 12 months, with a follow-up recheck conducted at six months.

Grade 3 leaks are repaired opportunistically with a target of repairing approximately 1000 leaks per year as approved by the CPUC.[5]

PG&E continues to repair all Class A and indoor Class B meter set leaks immediately, and during the 2024 Compliance Plan period prioritized the repair of outdoor Class B leaks (larger emitters) over Class C and Class D leaks to maximize methane abatement. This prioritization resulted in some class C and Class D leaks remaining open beyond three years.

a) Best Practice(s) Addressed by this Chapter

Best Practice 21 – Find It/Fix It: Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event, more than three (3) years after discovery. Utilities may make reasonable exceptions for leaks that are costly to repair relative to the estimated size of the leak.

b) Effectiveness

Super Emitter vs Grade 3 Leaks Repair

PG&E's leak repair strategy demonstrates that the SE program delivers significantly higher emissions abatement per dollar compared to belowground Grade 3 repairs. Lowering the SE threshold from 10 scfh to 6 scfh in 2024 accelerated the identification and repair of 131 additional large leaks, delivering ~230 Mscf of incremental abatement per leak compared with ~39 Mscf from repairing a below-ground Grade 3 leak[6]. This shows that reducing the SE threshold and prioritizing large leaks for repair is more effective than repairing belowground grade 3 leaks.

[5] In 2022, the CPUC approved PG&E's request to reduce the repairs of belowground Grade 3 repairs to 1000 leaks per year.

[6] For super emitter leaks and Grade 3 leaks, the calculation assumes the leak stays open for three years, which is the survey interval. The calculation also assumes the difference in emissions between emissions for super emitter at 10 SCFH vs 6 SCFH to compare to the missions with Grade 3 leak emissions.

Super Emitter Program

In the 2024 Leak Abatement OIR Report, emissions from distribution mains and services leaks totaled 243 MMscf with the SE program. Without the SE program, the total emissions would have totaled 359 MMscf. The emissions abated through the SE program are ~116 MMscf (difference between scenarios with and without SE). The net annual cost for the SE program in 2024, which includes the SE survey and SE repairs, less the value of gas saved, is approximately $4.1 million, resulting in a standard cost-effectiveness of $31/Mscf in 2024 at 6 scfh.

The number of SE leaks repaired in 2025 will be provided in PG&E's 2025 Natural Gas Leak Abatement filing to be submitted in June 2026.

Grade 3 Leak Repairs

PG&E estimates that repairs of belowground Grade 3 leaks result in an approximate abatement of 39 Mscf per leak. The total emission reduction from repairing 1,028 belowground Grade 3 leaks in 2024 is ~ 40 MMscf. The net annual cost, which includes savings from gas not emitted, is $11.0 million, resulting in a standard cost effectiveness of $274/Mscf.

Class B Meter Set Leaks Prioritization

Starting in 2024, PG&E began prioritizing Class B meter set leak repairs due to their larger emissions reduction impact. In 2024, PG&E repaired 7,590 Class B leaks ahead of schedule, achieving ~106 MMscf emissions reduction and a standard cost effectiveness of $10/Mscf.

Part 2. Proposed New or Continuing Measure

For the 2026 Compliance Plan period, PG&E will continue to meet its leak repair and leak survey obligations in accordance with GO 112F, including the following actions:

- Continue repairing all Grade 1 and Grade 2 leaks in accordance with GO 112F requirements.
- Complete the super emitter survey at a reduced threshold of 5 scfh to prioritize the identification and repair of higher emitting leaks.
- Continue to repair approximately 1,000 below ground Grade 3 leaks per year and, consistent with GO 112F, promptly repair any Grade 3 leaks that develop into higher-grade leaks.

In addition to these compliance actions, PG&E proposes to continue prioritizing the repair of Class B meter set leaks. Class B meter set leaks emit higher levels of methane than Class C and Class D meter set leaks, and repairing Class B leaks provides significantly greater methane emissions reductions on a cost-effective basis. Based on PG&E's analysis, repairs of Class B meter set leaks are approximately seven times more cost effective than Class C leak repairs and approximately twenty times more cost effective than Class D leak repairs, when measured as cost per unit of methane abated.

Beginning in 2024, PG&E increased its focus on the identification and repair of Class B meter set leaks and achieved measurable improvements. As a result of this focused effort, the average

number of days that Class B meter set leaks remained open was reduced from approximately 462 days in January 2025 to 235 days by December 2025. This improvement demonstrates the effectiveness of prioritizing Class B meter set leak repairs to achieve greater methane emissions reductions.

Building on this demonstrated success, PG&E proposes to continue this prioritization strategy in 2026 and beyond. Under this compliance plan, PG&E's objective is to further reduce the average number of days these class B leaks remain open, with a target of repairing indoor class B meter set leaks immediately and outdoor class B leaks within 180 days. This approach supports PG&E's methane emissions reduction goals by focusing on the most cost effective measures. Achieving this result requires approval from the CPUC to have flexibility with respect to the repair of outdoor Class C and Class D meter set leaks. PG&E will have a target to repair indoor Class C and Class D meter set leaks within 12 months, while outdoor class C and class D meter set leaks will be repaired on an opportunity basis when other work is already scheduled at the same location. This flexibility would allow PG&E to defer repairs of nonhazardous Class C and D repairs while continuing to promptly address hazardous conditions, thereby ensuring public safety is maintained.

This proposed approach is reasonable and justified because repairs of Class B meter set leaks provide greater methane emissions reductions per dollar spent compared to repairs of nonhazardous Class C and Class D meter set leaks. Prioritizing Class B meter set leak repairs in 2026 and beyond therefore represents a cost-effective, emissions focused, and performance based strategy consistent with GO 112F and PG&E's methane abatement objectives.

Part 3. Abatement Estimates

Super Emitter Leak Abatement

For the 2026 SE survey, PG&E will continue to perform the SE leak survey at 5 scfh. PG&E estimates ~83MMscf additional abatement due to the SE program vs traditional leak survey methods.

Belowground Grade 3 Leak Abatement

PG&E estimates ~39 Mscf of methane released per Grade 3 leak, assuming the leak stays open for 3 years. The total annual emission reduction from repairing 1,000 belowground Grade 3 leaks (the CPUC approved target) is calculated to be 39 MMscf.

Meter Set Leak (MSL) Abatement

For MSL, PG&E estimates approximately 258 MMscf of methane abatement from prioritizing meter set leak repairs. This estimate is based on a MSL emission calculation that assumes a 35% reduction compared to the 2024 leak-based approach baseline value. The 35% reduction reflects immediate repairs for Class A MSL and repairs of Class B MSL within six months. This calculation also assumes the leak remains open for three years, consistent with the survey interval.

Part 4. Cost Estimates and Average Annual Revenue Requirement

2026-2027 forecast (program-level):

Super Emitter Survey
2026: $2.0 million
2027: $2.0 million

Grade 3 Leak Repairs
2026: $12.3 million
2027: $15.3 million

Meter Set Leaks
2026: $11.7 million
2027: $10.7 million

No incremental funding is required to complete the forecasted work beyond what's approved through the GRC process.

Part 5. Cost Effectiveness/Benefits

The forecasted average annual revenue requirement for the SE survey and repair program is $11.1 million. The net annual cost, which includes cost savings of gas not emitted by the repairs, is $10 million. Dividing the net annual cost by the emissions reduction, the standard cost effectiveness is approximately $23/Mscf. In comparison, the standard cost effectiveness for repairing a belowground grade 3 leak is $274/Mscf. Therefore, SE leak repairs continue to be a more cost-effective measure in reducing emissions from gas distribution leaks over below ground Grade 3 leak repairs.

The forecasted average annual revenue requirement for meter set leak repairs is $11.2 million. The net annual cost, which includes the cost savings of gas not emitted by MSL repairs, is $10.4 million. Dividing the net annual cost by emission reduction savings yields a standard cost effectiveness of $39/Mscf. Including the benefits of Cap-and-Trade and the social cost of methane, the cost effectiveness improves to $13/Mscf.

CHAPTER 12: PIPE FITTING SPECIFICATIONS

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E has a robust and programmatic system for updating its standards and procedures around pipe fitting specifications which exceed American Society of Mechanical Engineers (ASME) standards. The program includes continuous evaluation of tools, technology, and procedures to address changes in code and compliance.

As of this Compliance Plan period, PG&E published the following guidance documents that reference the NPT standard for threads in its gas design standard documents:

Document Number	Document Title	Publication Date
B-10	Standard Pipe Caps	4/15/2020
B-10.1	Standard Pipe Plugs	4/15/2020
B-11	Standard Threaded Pipe Couplings	4/15/2020
B-11.1	Threaded Reducers (Bell Reducers)	4/15/2020
B-12.1	Standard Reducing 90° Elbows	4/15/2020
B-12.2	Standard 90° Threaded Street Elbows	4/15/2020
B-12.3	45° Threaded Elbow	4/15/2020
B-12.4	Reducing Street Elbow	4/15/2020
B-13.1	Extra-Heavy Pipe Nipples	7/19/2023
B-13.3	Concentric Reducing Nipple (Swage Nipple)	2/17/2021
B-13.4	Branch Nipple	11/15/2023
B-13.5	Stainless Steel Threaded Nipples	3/16/2022
B-14	Standard Threaded Tee	4/15/2020
B-14.1	Standard Threaded Street Tee	4/15/2020
B-14.2	Reducing Threaded Tee	4/15/2020
B-15	Standard Threaded Unions	4/15/2020
B-15.1	Threaded Bushing	4/15/2020
B-23.2	Threaded Nipolets	5/19/2021
B-30	90° Pipe Bends	3/18/2020
B-40.3	Blind Flanges	11/17/2021
B-40.4	Threaded Flanges and Threaded Reducing Flanges	11/17/2021
B-40.8	Orifice Flanges	9/20/2023
B-62	Stainless Steel Tube Fittings	2/1/2024
B-63	Threaded Stainless Steel Fittings	3/16/2022
B-71	Insulating Bushings	5/26/2025
B-72	Insulated Threaded Unions	5/26/2025
C-64.1	TDW Shortstop II: 6”–12” Fitting	5/17/1999
EMS-4765	Specifications for Furnishing and Delivery of Pre-Fabricated Metal-Cased Polyethylene (PE) Gas Service Risers	4/6/2021

EMS-5020	Steel Threaded Pipe Nipples, Gas Meter Assemblies, Meter Nuts, and Forged/Malleable Iron Threaded Gas Fittings	6/4/2025
EMS-5040	Specifications for Furnishing and Delivery of Natural Gas Filters	12/19/2018
F-80	Meter Valves	2/17/2021
H-60.4	Itron (Actaris/Schlumberger/Sprague) B42R and B42R Curb Regulators	10/24/2024
J-52.1	Gas Meter Manifolds (1-1/4 Inch and 2 Inch Sizes)	5/6/2025
J-57	Meter Outlet Angle Valve	11/18/2020

a) Best Practice(s) Addressed by this Chapter

Best Practice 22 – Pipe Fitting Specifications: Companies shall review and revise pipe fitting specifications, as necessary, to ensure tighter tolerance/better quality pipe threads. Utilities are required to review any available data on its threaded fittings, and if necessary, propose a fitting replacement program for threaded connections with significant leaks or comprehensive procedures for leak repairs and meter set assembly installations and repairs as part of their Compliance Plans. A fitting replacement program should consider components such as pressure control fittings, service tees, and valves metrics, among other things.

b) Effectiveness

This measure utilizes PG&E's existing process of updating its standards and procedures thus its effectiveness cannot be measured in emissions reduction.

Part 2. Proposed New or Continuing Measure

PG&E will continue to utilize its existing programmatic system for pipe specifications as it includes a continuous improvement component that incorporates new tools, technology, and procedures to address changing code and compliance. The Standards Engineering team will continue to explore opportunities to use prefabricated components that will reduce the number of threaded connections.

Part 3. Abatement Estimates

This measure focuses on review and updating standards and procedures as well as continuous improvement in reducing threaded connections; therefore, emissions reduction for this measure cannot be calculated.

Part 4. Cost Estimates and Average Annual Revenue Requirement

As stated above, this measure utilizes existing processes to review and update guidance documents and is performed by PG&E's Standards Engineering team. Funding for Standards Engineering work has been accounted for in PG&E's GRC under Operational Management and Operational Support. No incremental funding is requested beyond what is approved through the GRC process.

Part 5. Cost Effectiveness/Benefits

This measure utilizes PG&E's existing process of updating its standards and procedures; therefore, emissions reduction cannot be calculated based on this measure.

CHAPTER 13: HIGH-BLEED PNEUMATIC DEVICE REPLACEMENTS

Part 1. Evaluate the Current Practices Addressed in this Chapter

As reported on the 2024 Leak OIR Report, PG&E has zero high-bleed pneumatic devices at both Underground Storage Facilities (Appendix 7) and Compression and Processing Facilities (Appendix 3). PG&E has existing programs in place for replacing obsolete equipment at gas Transmission M&R Stations. During the 2024 Compliance Plan period there were four station rebuild projects where a total of 17 high-bleed pneumatic devices were removed or replaced.

Transmission Compressor Station Facilities:

As required by the CARB Oil and Gas Rule, as of January 1, 2019, PG&E addressed all remaining high bleed devices at the Compressor Stations and Underground Storage Facilities by either replacing them with intermittent or low bleed controllers, removing the device, or converting them to compressed air. In the 2024 Compliance Plan period, PG&E retired the Tionesta Compressor Station, eliminating 18 intermittent valve actuators resulting in emissions reduction of 0.379 MMscf/yr.

Transmission M&R Station Facilities

PG&E continues to identify, remove and replace the high bleed devices (Bristol controllers, Moore 74G and Fisher Positioners) with low-bleed and zero-bleed devices at its Transmission M&R Stations. In the 2024 Compliance Plan period, PG&E replaced or removed 17 high bleed controller devices at 4 Transmission M&R stations.

a) Best Practice(s) Addressed by this Chapter

Best Practice 23 – Minimize Emissions from Operations, Maintenance and Other Activities: Utilities shall minimize emissions from operations, maintenance, and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e., no bleed) or vents significantly less natural gas (i.e., low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

b) Effectiveness

During the 2024 Compliance Plan period, PG&E removed 17 high bleed controllers at 4 Transmission M&R stations. Annual emissions savings are 2.8 MMscf[7].

[7] Emission factors from Appendix 9 of the Natural Gas Leak Abatement Report were used to estimate emissions from high-bleed controllers (18.6 scfh).

Part 2. Proposed New or Continuing Measure

During the 2026 Compliance Plan period PG&E plans to replace 2 high bleed devices with low or zero bleed devices at 2 Transmission M&R Stations resulting in an annual emissions savings of 0.3 MMscf.

The replacement of high bleed devices at Compressor Stations and underground storage facilities were addressed as part of the CARB Oil and Gas Rule. There are no incremental requirements associated with this Best Practice.

Part 3. Abatement Estimates

Planned replacement of high-bleed pneumatic devices with low-bleed devices during the 2026 Compliance Plan period is expected to reduce annual emissions by approximately 0.3 MMscf.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Replacement or removal of high-bleed controllers will be performed as part of station rebuilds, which had funding adopted in the 2023 GRC Final Decision. No additional funding is requested for this measure.

Beyond the 2026 Compliance Plan period, PG&E will continue to minimize emissions from operations by choosing low-bleed or no-bleed devices for station rebuilds.

Part 5. Cost Effectiveness/Benefits

Replacements and removals of high-bleed pneumatic devices at Transmission M&R Stations have been conducted under planned station rebuild projects. Therefore, during the 2024 Compliance Plan period, there has been no incremental cost associated with the population reduction of high-bleed pneumatic devices.

CHAPTER 14: DAMAGE PREVENTION

Part 1. Evaluate the Current Practices Addressed in this Chapter

Public Education

PG&E has a comprehensive public awareness program in the area of "call before you dig." Part of the program is the "811 Ambassador Program," which offers financial rewards to employees who identify contractors digging without an Underground Service Alert (USA) ticket. The 811 Ambassador calls have been summarized in Table 11 below:

Table 11 – Number of 811 Ambassador Calls by Year (2018 – 2025)								
Year	2018	2019	2020	2021	2022	2023	2024	2025
Number of Calls	3,001	5,858	1,824	955	755	605	347	921

PG&E's Dig-in Reduction Team (DiRT) provides in-person safe excavation training, free of charge to the public. Summarized in Table 12 below is the number of classes PG&E has held over the years:

Table 12 – Number of DiRT Training Classes Provided by Year (2018 – 2025)								
Year	2018	2019	2020	2021	2022	2023	2024	2025
Number of Calls	226	148	132	137	184	392	383	471

PG&E maintains a "safe digging" website to provide instruction to excavators on safe digging practices. This information is delivered to excavators in email messaging and social media outreach.

In 2025, as a result of these ongoing programs, PG&E experienced 0.83 total gas dig-in rate per 1,000 USA tickets, exceeding the 2025 target of 1.03 third-party dig-ins per 1,000 tickets.

Stand-by Monitors

PG&E currently requires stand-by monitors to be present when excavation work is done within 10 feet of gas transmission lines[8]. This is communicated to excavators through the USA ticket process; the locator, upon identifying the transmission facility, arranges a field meet with the excavator to discuss the schedule and stand-by process. PG&E provides this service (locating, field meet, and stand-by during excavation) free of charge.

Dig-In Reduction Team

PG&E's DiRT investigates and educates excavators who damage PG&E's underground facilities. The DiRT has a process to identify and interact with contractors who are responsible for multiple dig-ins during a 12 to 24-month period. The DiRT provides safe digging classes free of charge, meets with third-party company leadership to establish ongoing relationships, and documents the damages for billing purposes. The DiRT works on a regional level with municipalities to educate excavators on safe digging practices and work through an escalation process when there are recurring issues with excavators, which can result in referrals to the Contractor State License Board.

a) Best Practice(s) Addressed by this Chapter

Best Practice 24 - Dig-Ins / Public Education Program: Dig-Ins – Expand existing public education program to alert the public and third-party excavation contractors to the Call Before You Dig – 811 program. In addition, utilities must provide procedures for excavation contractors to follow when excavating to prevent damaging or rupturing a gas line.

Best Practice 25 - Dig-Ins / Company Standby Monitors: Dig-Ins – Utilities must provide company monitors to witness all excavations near gas transmission lines to ensure that contractors are following utility procedures to properly excavate and backfill around transmission lines.

Best Practice 26 - Dig-Ins / Repeat Offenders: Dig-Ins - Utilities shall document procedures to address Repeat Offenders such as providing post-damage safe excavation training and on-site spot visits. Utilities shall keep track and report multiple incidents, within a 5-year period of dig- ins from the same party in their Annual Emissions Inventory Reports. These incidents and leaks shall be recorded as required in the recordkeeping best practice. In addition, the utility should report egregious offenders to appropriate enforcement agencies including the California Contractor's State License Board. The Board has the authority to investigate and punish dishonest or negligent contractors. Punishment can include suspension of their contractor's license.

b) Effectiveness

PG&E's damage prevention efforts have led to a measurable reduction in emissions associated with pipeline damages. When comparing 2024 emissions to the 2015 baseline for Transmission Pipeline – All Damages, Distribution Main & Service – All Damages, and Customer Meters – All Damages, PG&E achieved an emissions reduction of approximately 128 MMscf.

[8] California Government Code 4216 requires PG&E to arrange a field meet when a USA Ticket is requested for work within 10 feet of a gas transmission pipeline. PG&E's current practice provides, in addition to the field meet, a standby exceeding the regulation and adhering to best practice

Part 2. Proposed New or Continuing Measure

PG&E will continue implementing its damage prevention program to comply with these best practices. No new actions are proposed for the 2026 Compliance Plan period.

The compliance requirements/regulatory commitments that require a public awareness program include the following: California Government Code Section 4216; Code of Federal Regulations (CFR) Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Section (§) 192.703 (b) and (c), "General."; 49 CFR Part 196, "Protection of underground pipelines from excavation activity."; and Senate Bill 661, Chapter 809, September 29, 2016, SEC 23.955.5. PG&E's 811 Ambassador Program, the education programs delivered by the DiRT team, and Gold Shovel Program meet and exceed the public awareness regulations that govern PG&E gas transmission and distribution systems. No part of this measure is incremental to the regulations noted herein.

Part 3. Abatement Estimates

Emissions from pipeline damages can fluctuate from year to year, depending on the volume of construction activity. This emissions reduction is expected to remain unchanged for 2026-2027 as no incremental work is planned.

Part 4. Cost Estimates and Average Annual Revenue Requirement

PG&E's forecasted annual revenue requirement for Damage Prevention activities during the 2026-2027 Compliance Plan period is as follows:

2026
Public Awareness: $2.4 million
Dig-In Reduction Team: $4.3 million
Standby: $8.8 million

2027
Public Awareness: $2.9 million
Dig-In Reduction Team: $3.4 million
Standby: $7.2 million

No incremental funding is required to perform the work beyond what's approved through the GRC process to comply with this Best Practice.

Part 5. Cost Effectiveness/Benefits

The net annual cost is $13.6 million, which includes the average annualized revenue requirement of the activities in part 4 less the cost of gas saved. The standard cost effectiveness of this measure is $82/Mscf. The cost effectiveness when considering avoided Cap-and-Trade is $80/Mscf. The cost effectiveness when considering avoided Cap-and-Trade and social cost of methane is $54/Mscf.

CHAPTER 15: Research, Development and Demonstration (RD&D) PROJECTS

Part 1. Evaluate the Current Practices Addressed in this Chapter

Part 1 is not applicable because the RD&D projects proposed under this measure are forward-looking; therefore, this Best Practice cannot be compared.

Part 2. Proposed New or Continuing Measure

Starting in 2025, PG&E's Gas RD&D program received enhanced engagement and oversight from the CPUCs Climate & Equity Division. During this transitional period, the RD&D team is actively working to better align PG&E's research plan with CPUC priorities.

For the 2026 Compliance Plan period, the PG&E Gas RD&D team in coordination with California's RD&D administrators has taken the previous themes of maintaining and improving system safety, reducing methane emissions, and decarbonizing the gas system, and updated them into two forward-looking Gas themes:

Theme 1: Gas System Integrity

Theme 2: Decarbonization

Within these 2 themes, there are 6 initiatives

Theme	Initiative
Gas System Integrity	Proactive Geohazard Risk Management
	Innovative and Cost-Effective Integrity Management
	Advanced Leak Detection and Repair
	Emission Reduction Activities and Refined Reporting
Decarbonization	Clean Fuels Integration
	Sustainable Energy Solutions

The Natural Gas Leak Abatement Program aligns very closely with the Emissions Reduction Activities and Refined Reporting initiative within the Gas System Integrity theme. As part of its comprehensive climate strategy, PG&E has ambitious targets to lower greenhouse gas emissions over the next 15 years. Consistent with CPUC guidance, Gas RD&D activities described in this chapter are research and demonstration efforts intended to inform future decision-making, would reduce scope 1 methane emissions from PG&E's gas system, and support SB1371 related efforts.

Some projects in the gas system integrity theme, leak detection and repair initiative also align with the Natural Gas Leak Abatement Program. It is important to recognize that many of the projects in this category may not directly result in a visible methane emissions reduction; rather, their primary value lies in supporting ongoing compliance with the mandatory best practices with respect to

advanced leak detection and repair. This initiative supports ratepayer benefit by advancing research that improves the effectiveness, accuracy, and applicability of methane detection, quantification, and mitigation approaches, consistent with CPUC guidance

RD&D Emissions Reduction Activities and Refined Reporting

Some methane emissions are calculated using an outdated method that is not based on recent recorded data. While efficient, this approach does not provide accurate emissions estimates. Precise emissions data is crucial because it enables operators to identify which assets are currently releasing the most methane. This insight allows R&D teams to strategically plan and prioritize mitigation efforts, while focusing on the assets with the highest emissions. To address these challenges, Gas RD&D plans to continue research in projects that will allow the development of more granular emission calculation methods. Specifically, the projects in this category will focus on refining the reporting framework by demonstrating appropriate technologies and collecting data.

Some potential studies being considered include:

- Investigation of damages emission rates
- Top-down flyovers over transmission assets to quantify emissions
- Investigation of smart meters data to analyze MSA emissions data
- Optimization of leak survey
- Feasibility of a super emitter type program for the transmission system
- Demonstrating new blowdown and purging emissions reduction equipment

Advanced Leak Repair

During the last compliance plan period, PG&E demonstrated a new repair product for meter set leaks. The demonstration has multiple phases and remains ongoing. The PG&E Gas RD&D team has made several adjustments in response to feedback from operations. Projects in this area will continue to seek novel technologies that minimize repair times, reduce the need for follow-up service visits, adhere to seal quality & pressure requirements, and support subsequent replacements and repairs. Because visual atmospheric corrosion inspections of meter sets are costly and subjective, projects in this area also seek to develop technologies that can support remote monitoring of meter sets for corrosion and if corrosion is detected, alert repair crews, and/or shut off the meter set if failure is imminent.

Advanced Leak Detection

PG&E operates multiple assets, each requiring specific types of advanced leak detection. Projects in this area continually seek to develop cost-effective technologies for both leak detection and quantification. During the last compliance period, PG&E Gas RD&D demonstrated several advanced leak detection and monitoring technologies, including satellite technology for aerial leak detection, continuous leak monitoring tools to enhance safety at storage facilities, a helicopter mounted sensor for transmission leak surveys, and multiple drone-mounted methane sensors for

various applications. Through this work, the Gas RD&D successfully partnered with Operations to deploy two technologies that demonstrated strong performance.

Potential projects for the 2026 Compliance Plan period with respect to leak detection include:

- Demonstrating fixed wing aircrafts for leak detection to drive affordability for ratepayers through faster surveys with lower operational costs
- Demonstrating passive mobile leak detection to try to enhance leak find rate
- Testing other advanced leak detection technologies that enhance safety and drive affordability as they become readily available
- Testing scanning drone systems for aerial leak detection

a) Best Practices Addressed by this Chapter

Best Practice 20a - Quantification & Geographic Tracking: Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan on how they propose to address quantification. Utilities shall work together with the CPUC and CARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks for the purpose of tracking emissions reductions.

Best Practice 23 - Minimize Emissions from Operations, Maintenance and Other Activities: Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e., no bleed) or vents significantly less natural gas (i.e., low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

Part 3. Abatement Estimates

This measure focuses on RD&D projects and strategies that are forward-looking; therefore, emission reductions for this measure cannot be calculated.

Part 4. Cost Estimates and Average Annual Revenue Requirement

PG&E's Gas RD&D program has forecasted annual program expenditures (administration and research) of $8.2 million in 2026 and 2027 which require CPUC approval (currently pending). Please note that these costs are for the entire Gas RD&D program, and not just NGLA Compliance Plan activities. It is anticipated that approximately 15-20% of the research funding, if approved, will be used to support Compliance Plan activities.

Part 5. Cost Effectiveness/Benefits

Part 5 is not applicable as RD&D projects proposed under this measure are forward-looking.

SECTION C. SUPLEMENTAL MATERIALS

None

SECTION D. CONCLUSION The 2026 Compliance Plan meets the intent of SB 1371 by maintaining established Best Practices, documenting material reductions to date, aligning expenditures with cost-effective abatement, and setting a clear path to improve quantification methods that will enhance the integrity and comparability of future reported reductions. PG&E will continue proven measures in 2026–2027, including non-emergency transmission blowdown reduction strategies, annual AMLD-enabled Super Emitter surveys with a lower detection threshold to accelerate large-leak repairs, meter set leak repair prioritization, and sustained above-ground leak survey and repair programs, with no incremental funding requests in this filing. PG&E's RD&D team will continue to conduct research and development studies, in collaboration with CPUC and CARB, to develop new methods and technologies to enable methane emission reduction, refine emission factors for more accurate emissions reporting, and propose additional emission reduction activities that are both meaningful and cost effective.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 3

CHANGE LOGS FOR PG&E'S ASSET MANAGEMENT PLANS, GAS EMERGENCY RESPONSE PLAN, AND COMPANY EMERGENCY RESPONSE PLAN

Gas Guidance Document Analysis (GDA)
Strategic Asset Management Plan
GP-1100, Rev. 12, Publication Date: 12/09/2025

Document Type	Gas Plan
Workflow	Major Revision

1. What is Changing and Why?

The Pacific Gas and Electric Company (PG&E or Company) Gas Plan GP-1100, "Strategic Asset Management Plan," is updated per the annual review process by PG&E Asset Management Principals and associated leadership stakeholders.

This revision includes the following key changes (see Appendix A, "Change Log," in the document for additional details on these changes):

- Transitioned Gas Safety Excellence Management System (GSEMS) to PG&E Safety Excellence Management System (PSEMS) including reference to PSEMS policy and manual.
- Updated language to reflect PG&E's True North Strategy and long-term climate goals.
- Added 2040 strategic outcomes in alignment to True North Strategy objectives.
- Updated Research and Development (R&D) to reflect current structure and research objectives.
- Updated ISO 55001 clauses to 2024 version.
- Included general annual updates.

2. <u>Major</u> New Risks or Changes to Existing Mitigated Risks (such as Process Safety risks)

NA

© 2025 PG&E Corporation. All rights reserved.

3. Stakeholders

Table 1. Technical Stakeholder Reviewers (required to be considered)

Department / Work Center	Title (and Role if applicable)	Name (or reason if NA)	Review Date
Transmission Integrity Management	Principal Asset Management, Document Steward	[redacted]	06/2025
Standards Engineering	Principal Engineer, Document Coordinator	[redacted]	07/2025
Gas Transmission	Gas Reservoir Engineering Senior Director, Document Coordinator	[redacted]	06/2025
Standards Engineering	Principal Engineer, Lead Engineer	[redacted]	08/2025
Gas Engineering	Vice President, Document Approver	Austin Hastings (AAH7)	06/2025
Process Safety	NA – No changes to step-by-step field instructions		
Quality Management	NA – No associated quality assessments		
Operator Qualification	NA – No associated qualifications		
Technology Solutions	NA – No technology or electronic form changes required (Pronto, SAP)		
Regulatory Compliance	NA – No governing federal or state pipeline regulations		
PG&E Academy	NA – No associated Academy training		
As-Built Records	NA – Does not affect as-built documents		
Integrity Management (DIMP, FIMP, TIMP)	Senior Director, Gas Integrity Management	[redacted]	06/2025
	Principal Asset Management Specialist (TIMP)	[redacted]	06/2025
	Principal Asset Management Specialist (DIMP)	[redacted]	06/2025
	Principal Asset Management Specialist (FIMP)	[redacted]	06/2025
	Principal Business Operations Specialist (Gas Facilities & Storage Engineering)	[redacted]	06/2025
	Contractor (CNG/LNG)	[redacted]	06/2025

Table 2. Target Audience Usability Review (stakeholders that may review)

Department / Work Center	Title	Name	Review Date
Gas Management Systems & Enhanced Analytics	Senior Manager, Program Management	[redacted]	07/2025
Regulatory Compliance & Reporting	Senior Manager, Compliance and Risk	[redacted]	06/2025

© 2025 PG&E Corporation. All rights reserved.

4. Electronic Document Routing System (EDRS) Reviewers and Approvers

Approvers: [redacted] Austin Hastings (AAH7), Mik[redacted]

EDRS Routing Number: 2025-32614

5. Cost Information

NA

6. Schedule Information

Effective Date: 12/09/2025

For the communication plan, see Appendix G, "Gas Operations SAMP and AMPs Communication Plan Summary," in the document.

7. Work-in-Progress Direction

NA

8. Review Frequency

Updated as needed annually, or as special circumstances arise. (Not part of O&M manuals, not CFR requirement)

9. Cancellations

NA

10. Manuals

☒ No Change to Manuals

© 2025 PG&E Corporation. All rights reserved.

11. Document Properties

Functional Area

☒ No Change to Functional Area

☒ CNG-LNG	☒ Compression and Processing	☒ Customer Connected Equipment	☒ Distribution Mains
☒ Distribution Services	☒ Measurement and Control	☒ Storage	☒ Transmission Pipe

Target Audiences

☒ No Change to Target Audiences

☒ Asset Strategy	☒ Facility Integrity Management	☐ Leak Repair	☐ R&D and Innovation
☐ Associate Distribution Engineers	☒ GPOM (I&R)	☐ Leak Survey	☐ Records and Information Management
☒ Compliance and Risk	☐ Gas Control Strategy and Support	☐ Locate and Mark	☒ Regulatory Compliance
☐ Contract Management	☐ Gas Distribution Control Center	☐ Mapping (Transmission and Distribution)	☒ Risk Management
☐ Corrosion Mechanics	☐ Gas Emergency Preparedness	☐ Metering Plant	☐ Service Planning
☐ Corrosion Services	☒ Gas Operations Leadership	☐ Picarro	☐ Sourcing
☐ Data Quality	☐ Gas Service Representatives	☐ Pipeline Engineering	☐ Super Gas Ops
☐ Dispatch and Scheduling	☐ Gas Transmission Control Center	☐ Pipeline Safety Enhancement Plan Engineering	☐ System Planning
☐ Distribution Construction	☐ General Construction	☐ Program Management (Transmission and Distribution)	☐ Technology and Tools
☐ Distribution Engineering	☐ Hydrotesting	☐ Project Management (Transmission and Distribution)	☐ Transmission Construction
☒ Distribution Integrity Management	☒ Investment Planning	☐ Qualifications	☒ Transmission Engineering
☐ Estimating	☒ LNG|CNG Operations	☐ Quality and Improvement	☒ Transmission Integrity Management

Business Processes (GODOCS)

☒ No Change to Business Processes

CONSTRUCTION	ENGINEERING	MAINTENANCE & OPERATIONS	EMERGENCY / ADMIN
☐ As-Builts	☐ Applicant Design Manual	☐ Corrosion Control	☐ Dispatch and Scheduling
☐ Coatings	☐ Asset Knowledge Management	☐ Damage Prevention (indicate subtype)[1]	☐ Emergency Plans
☐ Construction Methods	☐ Distribution Engineering	☐ Field Services (GSRs)	☐ Gas Guidance Document Process
☐ Environmental and Safety	☒ Engineering for Integrity Management	☐ Gas Control and Clearances	☐ Gas Operations Quality Management
☐ Excavation	☐ Engineering Material Specifications	☐ Integrity Management (IM)	☒ Gas Safety Excellence
☐ Gas Design Standards for Construction	☐ Gas Design Standards	☐ Leak Survey and Response	☐ Operator Qualifications (OQ)
☐ Inspection and Operation	☒ Process Safety	☐ Major Stations	
☐ Plastic	☐ System Planning	☐ Measurement and Regulation (M&R)	
☐ Steel Pressure Control	☒ Transmission Engineering	☐ Steel Pipeline Maintenance and Repair	
☐ Strength Testing and Commissioning		☐ Valve Maintenance	
☐ Welding and Nondestructive Examination (NDE)			

1. Damage Prevention subtypes: Locate and Mark, Patrolling, Public Awareness

© 2025 PG&E Corporation. All rights reserved.

Gas Guidance Document Analysis (GDA)
Transmission Pipe Asset Management Plan
GP-1101, Rev. 12, Publication Date: 12/03/2025

Document Type	Gas Plan
Workflow	Major Revision

1. What Is Changing and Why?

Updated as recommended through the annual review process by PG&E Asset Management Principals and associated leadership stakeholders.

This major revision includes the following key changes (see Appendix F, "Change Log," within the document for additional details on the changes):

- Provided an annual update to the content, statistics, tables, and figures throughout the plan.
- Updated the strategic objectives, key metrics, and long-term goals.

2. Major New Risks or Changes to Existing Mitigated Risks (such as Process Safety risks)

NA

3. Stakeholders

Table 1. Technical Stakeholder Reviewers (required to be considered)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
Transmission Integrity Management Program (TIMP)	Principal, Document Steward	[redacted]	10/2025
Standards Engineering	Principal Engineer, Document Coordinator	[redacted]	10/2025
Standards Engineering	Principal Engineer, Lead Engineer	[redacted]	10/2025
Gas Transmission Engineering	Senior Director, Document Approver	[redacted]	10/2025
Process Safety Process-safety@pge.com	NA – No changes to step-by-step field instructions		
Quality Management	NA – No associated quality assessments		
Operator Qualification	NA – No associated qualifications		
Technology Solutions	NA – No technology or electronic form changes required (Pronto, SAP)		
Regulatory Compliance GasOpsSPRegulatoryCompliance@pge.com	NA – No governing federal or state pipeline regulations. No significant changes to TIMP program requiring Reg. Compliance review for notification purposes.		
PG&E Academy	NA – No associated Academy training		
As-Built Records	NA – Does not affect as-built documents		
Integrity Management (DIMP, FIMP, TIMP)	NA – Does not introduce a new part or change an existing part's specifications; change the installation, operation, maintenance, or removal process of any portion of an asset; change test requirements for any assets; or change data gathering or forms		

PG&E Internal Information © 2025 PG&E Corporation. All rights reserved.

Table 2. Target Audience Usability Review (stakeholders that may review)

Department / Work Center	Title	Name (LAN ID)	Date Provided	Gave Input?
Gas Safety Excellence	Manager	[redacted]	06/2025	no

4. Electronic Document Routing System (EDRS) Reviewers and Approvers

Approvers: [redacted]

EDRS Routing Number: 2025-46858

5. Cost Information

NA

6. Schedule Information

Effective Date: 12/03/2025. At the time of publication. The revision aligns with current practices.

GP-1101 will be implemented per Appendix G in GP-1100, "Strategic Asset Management Plan (SAMP) - Gas Operations SAMP and AMPs Communication Plan Summary," via the GTE Newsletter and Transmission Pipe asset family-specific employee meetings.

7. Review Frequency ☒ No Change to Review Frequency

8. Cancellations

NA

9. Manuals ☒ No Change to Manuals

PG&E Internal Information © 2025 PG&E Corporation. All rights reserved.

10. Document Properties

Functional Area

☐ CNG-LNG	☐ Compression and Processing	☐ Customer Connected Equipment	☐ Distribution Mains
☐ Distribution Services	☐ Measurement and Control	☐ Storage	☒ Transmission Pipe

Target Audiences

☒ Asset Strategy	☐ Facility Integrity Management	☐ Leak Repair	☒ R&D and Innovation
☐ Associate Distribution Engineers	☐ GPOM (I&R)	☐ Leak Survey	☐ Records and Information Management
☒ Compliance and Risk	☐ Gas Control Strategy and Support	☐ Locate and Mark	☐ Regulatory Compliance
☐ Contract Management	☐ Gas Distribution Control Center	☐ Mapping (Transmission and Distribution)	☒ Risk Management
☐ Corrosion Mechanics	☐ Gas Emergency Preparedness	☐ Metering Plant	☐ Service Planning
☐ Corrosion Services	☐ Gas Operations Leadership	☐ Picarro	☐ Sourcing
☐ Data Quality	☐ Gas Service Representatives	☒ Pipeline Engineering	☐ Super Gas Ops
☐ Dispatch and Scheduling	☐ Gas Transmission Control Center	☐ Pipeline Safety Enhancement Plan Engineering	☐ System Planning
☐ Distribution Construction	☐ General Construction	☒ Program Management (Transmission and Distribution)	☐ Technology and Tools
☐ Distribution Engineering	☐ Hydrotesting	☐ Project Management (Transmission and Distribution)	☐ Transmission Construction
☐ Distribution Integrity Management	☐ Investment Planning	☐ Qualifications	☒ Transmission Engineering
☐ Estimating	☐ LNG|CNG Operations	☐ Quality and Improvement	☒ Transmission Integrity Management

Business Processes (GODOCS)

CONSTRUCTION	ENGINEERING	MAINTENANCE & OPERATIONS	EMERGENCY / ADMIN
☐ As-Builts	☐ Applicant Design Manual	☐ Corrosion Control	☐ Dispatch and Scheduling
☐ Coatings	☐ Asset Knowledge Management	☐ Damage Prevention (indicate subtype)[1]	☐ Emergency Plans
☐ Construction Methods	☐ Distribution Engineering	☐ Field Services (GSRs)	☐ Gas Guidance Document Process
☐ Environmental and Safety	☒ Engineering for Integrity Management	☐ Gas Control and Clearances	☐ Gas Operations Quality Management
☐ Excavation	☐ Engineering Material Specifications	☒ Integrity Management (IM)	☒ Gas Safety Excellence
☐ Gas Design Standards for Construction	☐ Gas Design Standards	☐ Leak Survey and Response	☐ Operator Qualifications (OQ)
☐ Inspection and Operation	☒ Process Safety	☐ Major Stations	
☐ Plastic	☐ System Planning	☐ Measurement and Regulation (M&R)	
☐ Steel Pressure Control	☒ Transmission Engineering	☐ Steel Pipeline Maintenance and Repair	
☐ Strength Testing and Commissioning		☐ Valve Maintenance	
☐ Welding and Nondestructive Examination (NDE)			

1. Damage Prevention subtypes: Locate and Mark, Patrolling, Public Awareness

PG&E Internal Information © 2025 PG&E Corporation. All rights reserved.

Gas Guidance Document Analysis (GDA)
Gas Distribution Mains and Services Asset Management Plan
GP-1102, Rev. 12

Document Type	Gas Plan
Workflow	Major Revision

1. What is Changing and Why?

Major changes have been applied to every section (see Appendix F, "Change Log," Table 16, "AMP Change Log," for all changes). Key changes include:

- All statistics, tables, and figures have been updated to reflect most recent data available.
- Sections 1 through 5, and all appendices, have been updated for consistency with other gas plan documents.
- Updates to include revised and newly added strategic objectives.

2. Major New Risks or Changes to Existing Mitigated Risks (such as Process Safety risks)

NA

3. Stakeholders

Table 1. Technical Stakeholder Reviewers (required to be considered)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
Distribution Integrity Management Program (DIMP)	Principal Asset Family, Document Steward	[redacted]	07/2025
Standards Engineering	Senior Gas Engineer, Document Coordinator	[redacted]	07/2025
Standards Engineering	Principal Engineer, Lead Engineer	[redacted]	10/2025
DIMP	Senior Director, Document Approver	[redacted]	10/2025
Process Safety Process-safety@pge.com	NA – No changes to step-by-step field instructions		
Quality Management	NA – No associated quality assessments		
Operator Qualification	NA – No associated qualifications		
Technology Solutions	NA – No technology or electronic form changes required (Pronto, SAP)		
Regulatory Compliance GasOpsSPRegulatoryCompliance@pge.com	NA – No governing federal or state pipeline regulations		
PG&E Academy	NA – No associated Academy training		
As-Built Records	NA – Does not affect as-built documents		
Integrity Management (DIMP, FIMP, TIMP)	NA – Does not introduce a new part or change an existing part's specifications; change the installation, operation, maintenance, or removal process of any portion of an asset; change test requirements for any assets; or change data gathering or forms		

© 2025 PG&E Corporation. All rights reserved.

Table 2. Target Audience Usability Review (stakeholders that may review)

Department / Work Center	Title	Name (LAN ID)	Date Provided	Gave Input?
Management Systems and Enhanced Analytic	Business Project Manager, Principal	[redacted]	05/27/2025	No

4. Electronic Document Routing System (EDRS) Reviewers and Approvers

Approvers: [redacted]

EDRS Routing Number: 2025-40150

5. Cost Information

NA

6. Schedule Information

Effective Date: 11/19/2025

Gas Plan GP-1102 will be implemented per GP-1100, "Strategic Asset Management Plan," Appendix G, "Gas Operations SAMP and AMPs Communication Plan Summary."

7. Work-in-Progress Direction

NA

8. Review Frequency ☒ No Change to Review Frequency

9. Cancellations

NA

10. Manuals ☒ No Change to Manuals

© 2025 PG&E Corporation. All rights reserved.

11. Document Properties

Functional Area

☐ CNG-LNG	☐ Compression and Processing	☐ Customer Connected Equipment	☒ Distribution Mains
☒ Distribution Services	☐ Measurement and Control	☐ Storage	☐ Transmission Pipe

Target Audiences

☒ Asset Strategy	☐ Facility Integrity Management	☐ Leak Repair	☒ R&D and Innovation
☒ Associate Distribution Engineers	☐ GPOM (I&R)	☐ Leak Survey	☐ Records and Information Management
☒ Compliance and Risk	☐ Gas Control Strategy and Support	☐ Locate and Mark	☐ Regulatory Compliance
☒ Contract Management	☒ Gas Distribution Control Center	☐ Mapping (Transmission and Distribution)	☒ Risk Management
☒ Corrosion Mechanics	☒ Gas Emergency Preparedness	☐ Metering Plant	☐ Service Planning
☒ Corrosion Services	☒ Gas Operations Leadership	☐ Picarro	☐ Sourcing
☒ Data Quality	☐ Gas Service Representatives	☐ Pipeline Engineering	☐ Super Gas Ops
☐ Dispatch and Scheduling	☐ Gas Transmission Control Center	☐ Pipeline Safety Enhancement Plan Engineering	☐ System Planning
☒ Distribution Construction	☐ General Construction	☒ Program Management (Transmission and Distribution)	☐ Technology and Tools
☒ Distribution Engineering	☐ Hydrotesting	☒ Project Management (Transmission and Distribution)	☐ Transmission Construction
☒ Distribution Integrity Management	☒ Investment Planning	☐ Qualifications	☐ Transmission Engineering
☐ Estimating	☐ LNG|CNG Operations	☐ Quality and Improvement	☐ Transmission Integrity Management

Business Processes (GODOCS)

CONSTRUCTION	ENGINEERING	MAINTENANCE & OPERATIONS	EMERGENCY / ADMIN
☐ As-Builts	☐ Applicant Design Manual	☐ Corrosion Control	☐ Dispatch and Scheduling
☐ Coatings	☐ Asset Knowledge Management	☐ Damage Prevention (indicate subtype)[1]	☐ Emergency Plans
☐ Construction Methods	☐ Distribution Engineering	☐ Field Services (GSRs)	☐ Gas Guidance Document Process
☐ Environmental and Safety	☒ Engineering for Integrity Management	☐ Gas Control and Clearances	☐ Gas Operations Quality Management
☐ Excavation	☐ Engineering Material Specifications	☒ Integrity Management (IM)	☒ Gas Safety Excellence
☐ Gas Design Standards for Construction	☐ Gas Design Standards	☐ Leak Survey and Response	☐ Operator Qualifications (OQ)
☐ Inspection and Operation	☒ Process Safety	☐ Major Stations	
☒ Plastic	☐ System Planning	☐ Measurement and Regulation (M&R)	
☐ Steel Pressure Control	☐ Transmission Engineering	☒ Steel Pipeline Maintenance and Repair	
☐ Strength Testing and Commissioning		☐ Valve Maintenance	
☐ Welding and Nondestructive Examination (NDE)			

1. Damage Prevention subtypes: Locate and Mark, Patrolling, Public Awareness

© 2025 PG&E Corporation. All rights reserved.

Gas Guidance Document Analysis (GDA)
Customer-Connected Equipment Asset Management Plan
GP-1103, Rev. 12

Document Type	Gas Plan
Workflow	Major Revision

1. What is Changing and Why?

Major changes have been applied to every section (see Appendix F, "Change Log," Table 13, "AMP Change Log," for all changes implements). Key changes include:

- All statistics, tables, and figures have been updated to reflect current data.
- Sections 1 through 5, and all appendices, have been updated for consistency with other gas plan documents.

2. Major New Risks or Changes to Existing Mitigated Risks (such as Process Safety risks)

NA

3. Stakeholders

Table 1. Technical Stakeholder Reviewers (required to be considered)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
Distribution Integrity Management Program (DIMP)	Principal Asset Family, Document Steward	[redacted]	07/2025
Standards Engineering	Expert Distribution Specialist, Document Coordinator	[redacted]	08/2025
Standards Engineering	Principal Engineer, Lead Engineer	[redacted]	08/2025
DIMP	Senior Director, Document Approver	[redacted]	06/2025
Process Safety Process-safety@pge.com	NA – No changes to step-by-step field instructions		
Quality Management	NA – No associated quality assessments		
Operator Qualification	NA – No associated qualifications		
Technology Solutions	NA – No technology or electronic form changes required (Pronto, SAP)		
Regulatory Compliance GasOpsSPRegulatoryCompliance@pge.com	NA – No governing federal or state pipeline regulations		
PG&E Academy	NA – No associated Academy training		
As-Built Records	NA – Does not affect as-built documents		
Integrity Management (DIMP, FIMP, TIMP)	NA – Does not introduce a new part or change an existing part's specifications; change the installation, operation, maintenance, or removal process of any portion of an asset; change test requirements for any assets; or change data gathering or forms		

© 2025 PG&E Corporation. All rights reserved.

Table 2. Target Audience Usability Review (stakeholders that may review)

Department / Work Center	Title	Name (LAN ID)	Date Provided	Gave Input?
Management Systems and Enhanced Analytic	Business Project Manager, Principal	[redacted]	05/27/2025	No

4. Electronic Document Routing System (EDRS) Reviewers and Approvers

Approvers: [redacted]

EDRS Routing Number: 2025-34800

5. Cost Information

NA

6. Schedule Information

Effective Date: On publication 09/17/2025

Gas Plan GP-1103 will be implemented per Appendix G in Gas Plan GP-1100, "Strategic Asset Management Plan (SAMP) – Gas Operations SAMP and AMPs Communication Plan Summary."

7. Work-in-Progress Direction

NA

8. Review Frequency ☒ No Change to Review Frequency

9. Cancellations

NA

10. Manuals ☒ No Change to Manuals

© 2025 PG&E Corporation. All rights reserved.

11. Document Properties

Functional Area

☐ CNG-LNG	☐ Compression and Processing	☒ Customer Connected Equipment	☐ Distribution Mains
☐ Distribution Services	☐ Measurement and Control	☐ Storage	☐ Transmission Pipe

Target Audiences

☒ Asset Strategy	☐ Facility Integrity Management	☐ Leak Repair	☒ R&D and Innovation
☒ Associate Distribution Engineers	☐ GPOM (I&R)	☐ Leak Survey	☐ Records and Information Management
☒ Compliance and Risk	☐ Gas Control Strategy and Support	☐ Locate and Mark	☐ Regulatory Compliance
☒ Contract Management	☒ Gas Distribution Control Center	☐ Mapping (Transmission and Distribution)	☒ Risk Management
☒ Corrosion Mechanics	☒ Gas Emergency Preparedness	☒ Metering Plant	☐ Service Planning
☒ Corrosion Services	☒ Gas Operations Leadership	☐ Picarro	☐ Sourcing
☒ Data Quality	☐ Gas Service Representatives	☐ Pipeline Engineering	☐ Super Gas Ops
☐ Dispatch and Scheduling	☐ Gas Transmission Control Center	☐ Pipeline Safety Enhancement Plan Engineering	☐ System Planning
☒ Distribution Construction	☐ General Construction	☒ Program Management (Transmission and Distribution)	☐ Technology and Tools
☒ Distribution Engineering	☐ Hydrotesting	☒ Project Management (Transmission and Distribution)	☐ Transmission Construction
☒ Distribution Integrity Management	☒ Investment Planning	☐ Qualifications	☐ Transmission Engineering
☐ Estimating	☐ LNG|CNG Operations	☐ Quality and Improvement	☐ Transmission Integrity Management

Business Processes (GODOCS)

CONSTRUCTION	ENGINEERING	MAINTENANCE & OPERATIONS	EMERGENCY / ADMIN
☐ As-Builts	☐ Applicant Design Manual	☐ Corrosion Control	☐ Dispatch and Scheduling
☐ Coatings	☐ Asset Knowledge Management	☐ Damage Prevention (indicate subtype)[1]	☐ Emergency Plans
☐ Construction Methods	☐ Distribution Engineering	☐ Field Services (GSRs)	☐ Gas Guidance Document Process
☐ Environmental and Safety	☒ Engineering for Integrity Management	☐ Gas Control and Clearances	☐ Gas Operations Quality Management
☐ Excavation	☐ Engineering Material Specifications	☒ Integrity Management (IM)	☒ Gas Safety Excellence
☐ Gas Design Standards for Construction	☐ Gas Design Standards	☐ Leak Survey and Response	☐ Operator Qualifications (OQ)
☐ Inspection and Operation	☒ Process Safety	☐ Major Stations	
☒ Plastic	☐ System Planning	☐ Measurement and Regulation (M&R)	
☐ Steel Pressure Control	☐ Transmission Engineering	☒ Steel Pipeline Maintenance and Repair	
☐ Strength Testing and Commissioning		☐ Valve Maintenance	
☐ Welding and Nondestructive Examination (NDE)			

1. Damage Prevention subtypes: Locate and Mark, Patrolling, Public Awareness

© 2025 PG&E Corporation. All rights reserved.

Gas Guidance Document Analysis (GDA)
Measurement and Control Asset Management Plan
GP-1104, Rev. 12

Document Type	Gas Plan
Workflow	Major Revision

1. What is Changing and Why?

This gas plan is being updated per the annual review process. It has been updated by Pacific Gas and Electric Company (PG&E or Company) asset management principals and associated stakeholders.

Major changes have been applied to all sections. Information on changes is contained in Appendix F, "Change Log."

2. Major New Risks or Changes to Existing Mitigated Risks (such as Process Safety risks)

NA

3. Stakeholders

Table 1. Technical Stakeholder Reviewers (required to be considered)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
Station Services	Principal Asset Family Specialist, Document Steward	[redacted]	10/2025
Standards Engineering	Manager, Document Coordinator	[redacted]	11/2025
	Principal Gas Engineer, Lead Engineer	[redacted]	12/2025
Regulation Engineering	Senior Manager, Document Approver	[redacted]	10/2025
Process Safety Process-safety@pge.com	NA – No changes to step-by-step field instructions		
Quality Management	NA – No associated quality assessments		
Operator Qualification	NA – No associated qualifications		
Technology Solutions	NA – No technology or electronic form changes required (Pronto, SAP)		
Regulatory Compliance GasOpsSPRegulatoryCompliance@pge.com	NA – No significant changes requiring Reg. Compliance review for notification purposes.		
PG&E Academy	NA – No associated Academy training		
As-Built Records	NA – Does not affect as-built documents		
Integrity Management (DIMP, FIMP, TIMP)	See Document Steward/Approver above.		

© 2025 PG&E Corporation. All rights reserved.

Table 2. Target Audience Usability Review (stakeholders that may review)

Department / Work Center	Title	Name (LAN ID)	Date Provided	Gave Input?
Measurement Services	Manager	[redacted]	10/2025	Yes
FIMP Risk	Manager	[redacted]	10/2025	Yes
	Gas IM Engineer, Principal	[redacted]	10/2025	Yes
Station Services	Gas IM Engineer, Principal	[redacted]	10/2025	Yes

4. Electronic Document Routing System (EDRS) Reviewers and Approvers

Approvers: Kevin [redacted]

EDRS Routing Number: 2025-49234

5. Cost Information

NA

6. Schedule Information

Effective Date: Effective upon publication

GP-1104 will be implemented per GP-1100, "Strategic Asset Management Plan," Appendix G, "Gas Operations SAMP and AMPs Communication Plan Summary."

7. Review Frequency ☒ No Change to Review Frequency

8. Cancellations

NA

9. Manuals ☒ No Change to Manuals

© 2025 PG&E Corporation. All rights reserved.

10. Document Properties

Functional Area

☐ CNG-LNG	☐ Compression and Processing	☐ Customer Connected Equipment	☐ Distribution Mains
☐ Distribution Services	☒ Measurement and Control	☐ Storage	☐ Transmission Pipe

Target Audiences

☒ Asset Strategy	☒ Facility Integrity Management	☐ Leak Repair	☒ R&D and Innovation
☐ Associate Distribution Engineers	☐ GPOM (I&R)	☐ Leak Survey	☐ Records and Information Management
☒ Compliance and Risk	☐ Gas Control Strategy and Support	☐ Locate and Mark	☐ Regulatory Compliance
☐ Contract Management	☐ Gas Distribution Control Center	☐ Mapping (Transmission and Distribution)	☒ Risk Management
☐ Corrosion Mechanics	☐ Gas Emergency Preparedness	☒ Metering Plant	☐ Service Planning
☐ Corrosion Services	☐ Gas Operations Leadership	☐ Picarro	☐ Sourcing
☐ Data Quality	☐ Gas Service Representatives	☐ Pipeline Engineering	☐ Super Gas Ops
☐ Dispatch and Scheduling	☐ Gas Transmission Control Center	☐ Pipeline Safety Enhancement Plan Engineering	☐ System Planning
☐ Distribution Construction	☐ General Construction	☐ Program Management (Transmission and Distribution)	☐ Technology and Tools
☐ Distribution Engineering	☐ Hydrotesting	☐ Project Management (Transmission and Distribution)	☐ Transmission Construction
☐ Distribution Integrity Management	☐ Investment Planning	☐ Qualifications	☐ Transmission Engineering
☐ Estimating	☐ LNG|CNG Operations	☐ Quality and Improvement	☐ Transmission Integrity Management

Business Processes (GODOCS)

CONSTRUCTION	ENGINEERING	MAINTENANCE & OPERATIONS	EMERGENCY / ADMIN
☐ As-Builts	☐ Applicant Design Manual	☐ Corrosion Control	☐ Dispatch and Scheduling
☐ Coatings	☐ Asset Knowledge Management	☐ Damage Prevention (indicate subtype)[1]	☐ Emergency Plans
☐ Construction Methods	☐ Distribution Engineering	☐ Field Services (GSRs)	☐ Gas Guidance Document Process
☐ Environmental and Safety	☒ Engineering for Integrity Management	☒ Gas Control and Clearances	☐ Gas Operations Quality Management
☐ Excavation	☐ Engineering Material Specifications	☒ Integrity Management (IM)	☒ Gas Safety Excellence
☐ Gas Design Standards for Construction	☐ Gas Design Standards	☐ Leak Survey and Response	☐ Operator Qualifications (OQ)
☐ Inspection and Operation	☒ Process Safety	☐ Major Stations	
☐ Plastic	☐ System Planning	☒ Measurement and Regulation (M&R)	
☐ Steel Pressure Control	☐ Transmission Engineering	☐ Steel Pipeline Maintenance and Repair	
☐ Strength Testing and Commissioning		☒ Valve Maintenance	
☐ Welding and Nondestructive Examination (NDE)			

1. Damage Prevention subtypes: Locate and Mark, Patrolling, Public Awareness

© 2025 PG&E Corporation. All rights reserved.

Gas Guidance Document Analysis (GDA)
Measurement and Control Asset Management Plan
GP-1105, Rev. 12

Document Type	Gas Plan
Workflow	Major Revision

1. What is Changing and Why?

This gas plan is updated as part of the annual review process by Pacific Gas and Electric Company (PG&E or Company) asset management principals and associated stakeholders.

Major changes have been applied to all sections. Information on changes is contained in Appendix F, "Change Log."

2. Major New Risks or Changes to Existing Mitigated Risks (such as Process Safety risks)

NA

3. Stakeholders

Table 1. Technical Stakeholder Reviewers (required to be considered)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
Station Services	Principal Asset Family Specialist, Document Steward	[redacted]	EDRS
Standards Engineering	Expert Gas Engineer, Document Coordinator	[redacted]	EDRS
	Principal Gas Engineer, Lead Engineer	[redacted]	EDRS
Regulation Engineering	Senior Manager, Document Approver	[redacted]	EDRS
Process Safety Process-safety@pge.com	NA – No changes to step-by-step field instructions		
Quality Management	NA – No associated quality assessments		
Operator Qualification	NA – No associated qualifications		
Technology Solutions	NA – No technology or electronic form changes required (Pronto, SAP)		
Regulatory Compliance GasOpsSPRegulatoryCompliance@pge.com	NA – No significant changes requiring Reg. Compliance review for notification purposes.		
PG&E Academy	NA – No associated Academy training		
As-Built Records	NA – Does not affect as-built documents		
Integrity Management (DIMP, FIMP, TIMP)	See Document Steward/Approver above.		

© 2025 PG&E Corporation. All rights reserved.

Table 2. Target Audience Usability Review (stakeholders that may review)

Department / Work Center	Title	Name (LAN ID)	Date Provided	Gave Input?
Station Services	Engineer, Principal	[redacted]	11/2025	Yes
	Gas Facility Engineer, Expert	[redacted]	11/2025	Yes
	Gas Facility Engineer, Expert	[redacted]	11/2025	Yes
	Gas Facility Engineer, Expert	[redacted]	11/2025	Yes
	Supervisor, Gas Facility Engineering	[redacted]	11/2025	Yes

4. Electronic Document Routing System (EDRS) Reviewers and Approvers

Approvers: [redacted]

EDRS Routing Number: 2025-50361

5. Cost Information

NA

6. Schedule Information

Effective Date: 12/30/2025, same as publication date. GP-1105 will be implemented per GP-1100, "Strategic Asset Management Plan," Appendix G, "Gas Operations SAMP and AMPs Communication Plan Summary."

7. Review Frequency ☒ No Change to Review Frequency

At least once every calendar year, not to exceed 15 months, to the date.

8. Cancellations

NA

9. Manuals ☒ No Change to Manuals

© 2025 PG&E Corporation. All rights reserved.

10. Document Properties

Functional Area

☐ CNG-LNG	☒ Compression and Processing	☐ Customer Connected Equipment	☐ Distribution Mains
☐ Distribution Services	☐ Measurement and Control	☐ Storage	☐ Transmission Pipe

Target Audiences

☒ Asset Strategy	☒ Facility Integrity Management	☐ Leak Repair	☒ R&D and Innovation
☐ Associate Distribution Engineers	☐ GPOM (I&R)	☐ Leak Survey	☐ Records and Information Management
☒ Compliance and Risk	☐ Gas Control Strategy and Support	☐ Locate and Mark	☐ Regulatory Compliance
☐ Contract Management	☐ Gas Distribution Control Center	☐ Mapping (Transmission and Distribution)	☒ Risk Management
☐ Corrosion Mechanics	☐ Gas Emergency Preparedness	☒ Metering Plant	☐ Service Planning
☐ Corrosion Services	☐ Gas Operations Leadership	☐ Picarro	☐ Sourcing
☐ Data Quality	☐ Gas Service Representatives	☐ Pipeline Engineering	☐ Super Gas Ops
☐ Dispatch and Scheduling	☐ Gas Transmission Control Center	☐ Pipeline Safety Enhancement Plan Engineering	☐ System Planning
☐ Distribution Construction	☐ General Construction	☐ Program Management (Transmission and Distribution)	☐ Technology and Tools
☐ Distribution Engineering	☐ Hydrotesting	☐ Project Management (Transmission and Distribution)	☐ Transmission Construction
☐ Distribution Integrity Management	☐ Investment Planning	☐ Qualifications	☐ Transmission Engineering
☐ Estimating	☐ LNG|CNG Operations	☐ Quality and Improvement	☐ Transmission Integrity Management

Business Processes (GODOCS)

CONSTRUCTION	ENGINEERING	MAINTENANCE & OPERATIONS	EMERGENCY / ADMIN
☐ As-Builts	☐ Applicant Design Manual	☐ Corrosion Control	☐ Dispatch and Scheduling
☐ Coatings	☐ Asset Knowledge Management	☐ Damage Prevention (indicate subtype)[1]	☐ Emergency Plans
☐ Construction Methods	☐ Distribution Engineering	☐ Field Services (GSRs)	☐ Gas Guidance Document Process
☐ Environmental and Safety	☒ Engineering for Integrity Management	☐ Gas Control and Clearances	☐ Gas Operations Quality Management
☐ Excavation	☐ Engineering Material Specifications	☒ Integrity Management (IM)	☐ Gas Safety Excellence
☐ Gas Design Standards for Construction	☐ Gas Design Standards	☐ Leak Survey and Response	☐ Operator Qualifications (OQ)
☐ Inspection and Operation	☒ Process Safety	☐ Major Stations	
☐ Plastic	☐ System Planning	☐ Measurement and Regulation (M&R)	
☐ Steel Pressure Control	☐ Transmission Engineering	☐ Steel Pipeline Maintenance and Repair	
☐ Strength Testing and Commissioning		☐ Valve Maintenance	
☐ Welding and Nondestructive Examination (NDE)			

1. Damage Prevention subtypes: Locate and Mark, Patrolling, Public Awareness

© 2025 PG&E Corporation. All rights reserved.

Gas Guidance Document Analysis (GDA)
LNG/CNG Asset Management Plan
GP-1106, Rev. 11

Document Type	Gas Plan
Workflow	Major Revision

1. What is Changing and Why?

This gas plan has been updated per the annual review process by Pacific Gas and Electric Company (PG&E or Company) asset management principals and associated leadership and subject matter expert stakeholders. Key changes include:

- Applied annual update to content, statistics, tables, and figures globally.
- Updated content in Sections 1 through 5 and all appendices to ensure document consistency with other gas plan documents.
- Updated strategic objectives and risk controls and programs.

2. Major New Risks or Changes to Existing Mitigated Risks (such as Process Safety risks)

NA

3. Stakeholders

Table 1. Technical Stakeholder Reviewers (required to be considered)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
LNG / CNG Operations and Engineering	Senior Manager, Document Steward	[redacted]	08/2025
Standards Engineering	Expert Gas Engineer, Document Coordinator	[redacted]	10/2025
	Principal Engineer, Lead Engineer	[redacted]	11/2025
LNG / CNG Operations and Engineering	Senior Manager, Document Approver	[redacted]	08/2025
Process Safety Process-safety@pge.com	NA – No changes to step-by-step field instructions		
Quality Management	NA – No associated quality assessments		
Operator Qualification	NA – No associated qualifications		
Technology Solutions	NA – No technology or electronic form changes required (Pronto, SAP)		
Regulatory Compliance GasOpsSPRegulatoryCompliance@pge.com	NA – No governing federal or state pipeline regulations. No significant changes to TIMP program requiring Reg. Compliance review for notification purposes.		
PG&E Academy	NA – No associated Academy training		

©2025 PG&E Corporation. All rights reserved.

3 (continued)

Table 1. Technical Stakeholder Reviewers (continued)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
As-Built Records	NA – Does not affect as-built documents		
Integrity Management (DIMP, FIMP, TIMP)	NA – Does not introduce a new part or change an existing part's specifications; change the installation, operation, maintenance, or removal process of any portion of an asset; change test requirements for any assets; or change data gathering or forms		

Table 2. Target Audience Usability Review (stakeholders that may review)

Department / Work Center	Title	Name (LAN ID)	Date Provided	Gave Input?
LNG / CNG Engineering	Manager	[redacted]	08/2025	Yes
LNG / CNG Operations and Engineering	Expert Gas Facility Engineer	[redacted]	08/2025	Yes
LNG / CNG Portable Engineering	Expert Gas Facility Engineer	[redacted]	08/2025	Yes
LNG / CNG Station Engineering	Supervisor, Gas Facility Engineering	[redacted]	08/2025	Yes
LNG / CNG Engineering	Principal Asset Family	[redacted]	08/2025	Yes

4. Electronic Document Routing System (EDRS) Reviewers and Approvers

Approvers: [redacted]

EDRS Routing Number: 2025-44355

5. Cost Information

NA

6. Schedule Information

Effective Date: Effective Upon Publication

GP-1106 will be implemented per Appendix G, "Asset Life Cycle," in GP-1100, "Strategic Asset Management Plan."

7. Work-in-Progress Direction

NA

8. Review Frequency ☒ No Change to Review Frequency

At least once every calendar year, not to exceed 15 months, to the date.

©2025 PG&E Corporation. All rights reserved.

9. Cancellations

NA

10. Manuals

☒ No Change to Manuals

11. Document Properties

Functional Area

☒ CNG-LNG	☐ Compression and Processing	☐ Customer Connected Equipment	☐ Distribution Mains
☐ Distribution Services	☐ Measurement and Control	☐ Storage	☐ Transmission Pipe

Target Audiences

☐ Asset Strategy	☐ Facility Integrity Management	☐ Leak Repair	☐ R&D and Innovation
☐ Associate Distribution Engineers	☐ GPOM (I&R)	☐ Leak Survey	☐ Records and Information Management
☐ Compliance and Risk	☐ Gas Control Strategy and Support	☐ Locate and Mark	☐ Regulatory Compliance
☐ Contract Management	☐ Gas Distribution Control Center	☐ Mapping (Transmission and Distribution)	☐ Risk Management
☐ Corrosion Mechanics	☐ Gas Emergency Preparedness	☐ Metering Plant	☐ Service Planning
☐ Corrosion Services	☐ Gas Operations Leadership	☐ Picarro	☐ Sourcing
☐ Data Quality	☐ Gas Service Representatives	☐ Pipeline Engineering	☐ Super Gas Ops
☐ Dispatch and Scheduling	☐ Gas Transmission Control Center	☐ Pipeline Safety Enhancement Plan Engineering	☐ System Planning
☐ Distribution Construction	☐ General Construction	☐ Program Management (Transmission and Distribution)	☐ Technology and Tools
☐ Distribution Engineering	☐ Hydrotesting	☐ Project Management (Transmission and Distribution)	☐ Transmission Construction
☐ Distribution Integrity Management	☐ Investment Planning	☐ Qualifications	☐ Transmission Engineering
☐ Estimating	☒ LNG|CNG Operations	☐ Quality and Improvement	☐ Transmission Integrity Management

©2025 PG&E Corporation. All rights reserved.

Business Processes (GODOCS)

CONSTRUCTION	ENGINEERING	MAINTENANCE & OPERATIONS	EMERGENCY / ADMIN
☐ As-Builts	☐ Applicant Design Manual	☐ Corrosion Control	☐ Dispatch and Scheduling
☐ Coatings	☐ Asset Knowledge Management	☐ Damage Prevention (indicate subtype)[1]	☐ Emergency Plans
☐ Construction Methods	☐ Distribution Engineering	☐ Field Services (GSRs)	☐ Gas Guidance Document Process
☐ Environmental and Safety	☒ Engineering for Integrity Management	☐ Gas Control and Clearances	☐ Gas Operations Quality Management
☐ Excavation	☐ Engineering Material Specifications	☒ Integrity Management (IM)	☒ Gas Safety Excellence
☐ Gas Design Standards for Construction	☐ Gas Design Standards	☐ Leak Survey and Response	☐ Operator Qualifications (OQ)
☐ Inspection and Operation	☒ Process Safety	☐ Major Stations	
☐ Plastic	☐ System Planning	☐ Measurement and Regulation (M&R)	
☐ Steel Pressure Control	☐ Transmission Engineering	☐ Steel Pipeline Maintenance and Repair	
☐ Strength Testing and Commissioning		☐ Valve Maintenance	
☐ Welding and Nondestructive Examination (NDE)			

1. Damage Prevention subtypes: Locate and Mark, Patrolling, Public Awareness

©2025 PG&E Corporation. All rights reserved.

Gas Guidance Document Analysis (GDA)
Underground Gas Storage Asset Management Plan
GP-1108, Rev. 12

Document Type	Gas Manual
Workflow	Major Revision

1. What is Changing and Why?

This gas manual is updated as required by the PG&E Asset Management team principals and associated leadership stakeholders' annual review process. Changes include:

- Annual update to the content, statistics, tables, and figures throughout the gas plan to align with annual updates.
- Added new tables, figures, and sections as documented in "Change Log."

See Appendix F, "Change Log," in the appendices section for additional details on the changes.

2. Major New Risks or Changes to Existing Mitigated Risks (such as Process Safety risks)

NA

3. Stakeholders

Table 1. Technical Stakeholder Reviewers (required to be considered)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
Gas Reservoir Engineering	Gas Storage Asset Analyst, Document Steward	[redacted]	EDRS
Standards Engineering	Expert Gas Engineer, Document Coordinator	[redacted]	EDRS
Standards Engineering	Principal Engineer, Lead Engineer	[redacted]	EDRS
Gas Facilities and Storage Engineering	Senior Director, Document Approver	[redacted]	EDRS
Process Safety Process-safety@pge.com	NA – No changes to step-by-step field instructions		
Quality Management	NA – No associated quality assessments		
Operator Qualification	NA – No associated qualifications		
Technology Solutions	NA – No technology or electronic form changes required (Pronto, SAP)		
Regulatory Compliance GasOpsSPRegulatoryCompliance@pge.com	NA – No governing federal or state pipeline regulations.		
PG&E Academy	NA – No associated Academy training		
As-Built Records	NA – Does not affect as-built documents		
Integrity Management (DIMP, FIMP, TIMP)	NA – Does not introduce a new part or change an existing part's specifications; change the installation, operation, maintenance, or removal process of any portion of an asset; change test requirements for any assets; or change data gathering or forms		

© 2025 PG&E Corporation. All rights reserved.

Table 2. Target Audience Usability Review (stakeholders that may review)

Department / Work Center	Title	Name (LAN ID)	Date Provided	Gave Input?
Gas Safety Excellence	Manager, Program Management	[redacted]	06/2025	Yes
Risk and Compliance	Gas Risk Manager	[redacted]	06/2025	Yes
Gas Engineering & Design	Manager, Gas Engineering & Design	[redacted]	09/2025	Yes
Distribution Integrity Management	DIMP Asset Family, Principal	[redacted]	09/2025	Yes
Transmission Integrity Management	TIMP Asset Family, Principal	[redacted]	09/2025	Yes
Facility Integrity Management	FIMP Asset Family, Principal	[redacted]	09/2025	Yes
Gas Reservoir Engineering	Gas Storage Reservoir Engineer, Associate	[redacted]	09/2025	Yes
Gas Reservoir Engineering	Manager, Gas Engineering & Design	[redacted]	09/2025	Yes
Gas Reservoir Engineering	Gas Storage Reservoir Engineer, Senior	[redacted]	09/2025	Yes

4. Electronic Document Routing System (EDRS) Reviewers and Approvers

Approvers: [redacted]

EDRS Routing Number: 2025-50374

5. Cost Information

NA

6. Schedule Information

Effective Date: 12/30/2025, same as publication date.

7. Review Frequency ☒ No Change to Review Frequency

At least once every calendar year, not to exceed 15 months, to the date.

8. Cancellations

NA

© 2025 PG&E Corporation. All rights reserved.

9. Manuals

☒ No Change to Manuals

10. Document Properties

Functional Area

☐ CNG-LNG	☐ Compression and Processing	☐ Customer Connected Equipment	☐ Distribution Mains
☐ Distribution Services	☐ Measurement and Control	☒ Storage	☐ Transmission Pipe

Target Audiences

☒ Asset Strategy	☒ Facility Integrity Management	☐ Leak Repair	☒ R&D and Innovation
☐ Associate Distribution Engineers	☐ GPOM (I&R)	☐ Leak Survey	☐ Records and Information Management
☐ Compliance and Risk	☐ Gas Control Strategy and Support	☐ Locate and Mark	☐ Regulatory Compliance
☐ Contract Management	☐ Gas Distribution Control Center	☐ Mapping (Transmission and Distribution)	☒ Risk Management
☐ Corrosion Mechanics	☐ Gas Emergency Preparedness	☐ Metering Plant	☐ Service Planning
☐ Corrosion Services	☐ Gas Operations Leadership	☐ Picarro	☐ Sourcing
☐ Data Quality	☐ Gas Service Representatives	☐ Pipeline Engineering	☐ Super Gas Ops
☐ Dispatch and Scheduling	☐ Gas Transmission Control Center	☐ Pipeline Safety Enhancement Plan Engineering	☐ System Planning
☐ Distribution Construction	☐ General Construction	☐ Program Management (Transmission and Distribution)	☐ Technology and Tools
☐ Distribution Engineering	☐ Hydrotesting	☐ Project Management (Transmission and Distribution)	☐ Transmission Construction
☐ Distribution Integrity Management	☐ Investment Planning	☐ Qualifications	☐ Transmission Engineering
☐ Estimating	☐ LNG|CNG Operations	☐ Quality and Improvement	☐ Transmission Integrity Management

© 2025 PG&E Corporation. All rights reserved.

Business Processes (GODOCS)

CONSTRUCTION	ENGINEERING	MAINTENANCE & OPERATIONS	EMERGENCY / ADMIN
☐ As-Builts	☐ Applicant Design Manual	☐ Corrosion Control	☐ Dispatch and Scheduling
☐ Coatings	☐ Asset Knowledge Management	☐ Damage Prevention (indicate subtype)[1]	☐ Emergency Plans
☐ Construction Methods	☐ Distribution Engineering	☐ Field Services (GSRs)	☐ Gas Guidance Document Process
☐ Environmental and Safety	☒ Engineering for Integrity Management	☐ Gas Control and Clearances	☐ Gas Operations Quality Management
☐ Excavation	☐ Engineering Material Specifications	☐ Integrity Management (IM)	☒ Gas Safety Excellence
☐ Gas Design Standards for Construction	☐ Gas Design Standards	☐ Leak Survey and Response	☐ Operator Qualifications (OQ)
☐ Inspection and Operation	☒ Process Safety	☐ Major Stations	
☐ Plastic	☐ System Planning	☐ Measurement and Regulation (M&R)	
☐ Steel Pressure Control	☐ Transmission Engineering	☐ Steel Pipeline Maintenance and Repair	
☐ Strength Testing and Commissioning		☐ Valve Maintenance	
☐ Welding and Nondestructive Examination (NDE)			

1. Damage Prevention subtypes: Locate and Mark, Patrolling, Public Awareness

© 2025 PG&E Corporation. All rights reserved.

Gas Guidance Document Analysis (GDA)
Gas Data Asset Management Plan
GP-1109, Rev. 7

Document Type	Gas Plan
Workflow	Major Revision

1. What is Changing and Why?

This revision has been reformatted with major changes applied to every section (see Appendix F, "Change Log"). Key changes include:

- All tables and figures have been updated to reflect current data.
- Sections 1–5 and all appendices have been updated to ensure consistency and that asset information is current.
- Added references to Strategic Data Plans.

2. Major New Risks or Changes to Existing Mitigated Risks (such as Process Safety risks)

NA

3. Stakeholders

Table 1. Technical Stakeholder Reviewers (required to be considered)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
Distribution Integrity Management Program (DIMP)	Principal Asset Family, Document Steward	[redacted]	07/07/2024
Standards Engineering	Senior Gas Engineer, Document Coordinator	[redacted]	09/30/2024
Standards Engineering	Supervising Engineer, Lead Engineer	[redacted]	09/27/2024
Gas Data Management and Solutions	Director, Document Approver	[redacted]	07/15/2024
Process Safety Process-safety@pge.com	NA – No changes to step-by-step field instructions		
Quality Management	NA – No associated quality assessments		
Operator Qualification	NA – No associated qualifications		
Technology Solutions	NA – No technology or electronic form changes required (Pronto, SAP)		
Regulatory Compliance GasOpsSPRegulatoryCompliance@pge.com	NA – No governing federal or state pipeline regulations		
PG&E Academy	NA – No associated Academy training		
As-Built Records	NA – Does not affect as-built documents		
Integrity Management (DIMP, FIMP, TIMP)	NA – Does not change the installation, operation, maintenance, or removal process of any portion of an asset; change test requirements for any assets; or change data gathering or forms		

© 2024 PG&E Corporation. All rights reserved.

Table 2. Target Audience Usability Review (stakeholders that may review)

Department / Work Center	Title	Name (LAN ID)	Date Provided	Gave Input?
Gas Safety Excellence	Manager, Program Management	[redacted]	07/02/2024	Yes

4. Electronic Document Routing System (EDRS) Reviewers and Approvers

Approvers: [redacted]

EDRS Routing Number: 2024-38756

5. Cost Information

NA

6. Schedule Information

Effective Date: 10/01/2024

GP-1109 will be implemented per Appendix G in GP-1100, "Strategic Asset Management Plan (SAMP) - Gas Operations SAMP and AMPs Communication Plan Summary."

7. Work-in-Progress Direction

NA

8. Review Frequency

☒ No Change to Review Frequency

At least once every calendar year, not to exceed 15 months, to the date.

9. Cancellations

NA

10. Manuals

☒ No Change to Manuals

11. Document Properties

Functional Area

☐ CNG-LNG	☐ Compression and Processing	☐ Customer Connected Equipment	☒ Distribution Mains
☒ Distribution Services	☐ Measurement and Control	☐ Storage	☐ Transmission Pipe

© 2024 PG&E Corporation. All rights reserved.

Target Audiences

☒ Asset Strategy	☐ Facility Integrity Management	☐ Leak Repair	☒ R&D and Innovation
☐ Associate Distribution Engineers	☐ GPOM (I&R)	☐ Leak Survey	☐ Records and Information Management
☒ Compliance and Risk	☐ Gas Control Strategy and Support	☐ Locate and Mark	☐ Regulatory Compliance
☐ Contract Management	☐ Gas Distribution Control Center	☐ Mapping (Transmission and Distribution)	☒ Risk Management
☐ Corrosion Mechanics	☐ Gas Emergency Preparedness	☐ Metering Plant	☐ Service Planning
☐ Corrosion Services	☒ Gas Operations Leadership	☐ Picarro	☐ Sourcing
☐ Data Quality	☐ Gas Service Representatives	☐ Pipeline Engineering	☐ Super Gas Ops
☐ Dispatch and Scheduling	☐ Gas Transmission Control Center	☐ Pipeline Safety Enhancement Plan Engineering	☐ System Planning
☐ Distribution Construction	☐ General Construction	☒ Program Management (Transmission and Distribution)	☐ Technology and Tools
☒ Distribution Engineering	☐ Hydrotesting	☒ Project Management (Transmission and Distribution)	☐ Transmission Construction
☒ Distribution Integrity Management	☒ Investment Planning	☐ Qualifications	☐ Transmission Engineering
☐ Estimating	☐ LNG|CNG Operations	☐ Quality and Improvement	☐ Transmission Integrity Management

Business Processes (GODOCS)

CONSTRUCTION	ENGINEERING	MAINTENANCE & OPERATIONS	EMERGENCY / ADMIN
☐ As-Builts	☐ Applicant Design Manual	☐ Corrosion Control	☐ Dispatch and Scheduling
☐ Coatings	☐ Asset Knowledge Management	☐ Damage Prevention (indicate subtype)[1]	☐ Emergency Plans
☐ Construction Methods	☐ Distribution Engineering	☐ Field Services (GSRs)	☐ Gas Guidance Document Process
☐ Environmental and Safety	☒ Engineering for Integrity Management	☐ Gas Control and Clearances	☐ Gas Operations Quality Management
☐ Excavation	☐ Engineering Material Specifications	☒ Integrity Management (IM)	☒ Gas Safety Excellence
☐ Gas Design Standards for Construction	☐ Gas Design Standards	☐ Leak Survey and Response	☐ Operator Qualifications (OQ)
☐ Inspection and Operation	☒ Process Safety	☐ Major Stations	
☒ Plastic	☐ System Planning	☐ Measurement and Regulation (M&R)	
☐ Steel Pressure Control	☐ Transmission Engineering	☒ Steel Pipeline Maintenance and Repair	
☐ Strength Testing and Commissioning		☐ Valve Maintenance	
☐ Welding and Nondestructive Examination (NDE)			

1. Damage Prevention subtypes: Locate and Mark, Patrolling, Public Awareness

© 2024 PG&E Corporation. All rights reserved.

Document Control

This section contains Pacific Gas and Electric (PG&E) information related to the ownership and maintenance of this document. This document undergoes an annual review and update as needed and in compliance with EMER-2001S, Company Emergency Operations Plans Standard published in Guidance Document Library (GDL). Emergency Preparedness and Response (EP&R) maintains this Company Emergency Response Plan (CERP).

Change Record

The Change Record table given below is used to record all changes made to the plan. It describes the revisions made, the locations of the revisions, the names of the coworkers responsible for the revisions, and dates of revisions:

Section	Person Responsible for Revision	Change	Date
Throughout	[redacted]	Moved "Outage Notifications and External Agency Reporting" topic from Section 3 Concept of Operations to Section 4 Coordination and Communication. Removed repetitions and content covered in other GDL documents (Resource Management Process, Emergency Response Training Program, Enterprise After-Action Report standard and templates, SIPT standard, and Mutual Assistance Playbook). Consolidated and moved content covering PG&E alignment with SEMS and ICS from various locations to Section 3. Moved Materials and Transportation Coordination Center and Rental Central content from Section 12 to 9.6. Removed references to the Demobilization Unit.	11/20/2025
Plan Maintenance	[redacted]	Removed NERC CIP-008 applicable requirements to the Cyber Annex.	11/30/2025
1.7	[redacted]	Explained the establishment, organization, and succession requirements for the Enterprise Emergency Management Program.	11/18/2025
2.3 (Figure 2-2)	[redacted]	Updated the Regional Service Model Regions.	11/24/2025
2.2	[redacted]	Updated the PG&E Organizational Structure.	Various

Section	Person Responsible for Revision	Change	Date
2.10	[redacted]	Updated and made corrections.	11/25/2025
3.7 3.7.1	[redacted]	Updated and included EP&R EOC R&O monitoring actions. Changed “Pre-Incident Readiness” to “Pre-Incident Preparedness”.	11/25/2025
Throughout	[redacted]	Explained how PG&E is using the HIRA process to identify threats and hazards.	11/18/2025
4.1	[redacted]	Removed explanations of the NIMS Command and Coordination Structure. Explained that PG&E follows the NIMS Joint Information System (JIS).	11/20/2025
Throughout	[redacted]	Updated name changes to the GERP (now Gas Annex) and ITCC (now IOC).	8/26/2025
Throughout	[redacted]	Various edits to align language to updated configuration of Wildfire Mitigation program.	Various
Throughout	[redacted]	Various edits to align language to updated configuration of EP&R EOC Response & Operations.	Various
4.2.2	[redacted]	Updated that pre-incident summary reporting includes assessment of preparedness plans (not readiness plans).	11/25/2025
4.2.4	[redacted]	Updated the content.	11/25/2025
3.2.2	[redacted]	Added SEMS ICS Command and General Staff description.	10/13/25
3.2.3	[redacted]	Added Unity of Command description and PG&E Functional Area/EOC Command and General Staff crosswalk content.	10/13/25
5	[redacted]	Added Performance Indicator section and GO 166 standards 6, 7, 8, 12, and 13, mutual assistance evaluation, electric service restoration communications, and call center activities for major outage and measured event response requirements.	10/13/25
5.2.1	[redacted]	Updated the verbiage to align with the PSPS Annex, 4.5 PSPS Situational Intelligence Platform (PSIP)	9/18/2025
5.3.2	[redacted]	Updated the verbiage to align with the PSPS Annex, 5.2.1 Step 1: Minimum Fire Potential Conditions	9/18/2025

Section	Person Responsible for Revision	Change	Date
6.2.3	[redacted]	Revised language describing Geohazards.	Various
8.2.1	[redacted]	Updated the verbiage to align with the PSPS Annex, 3.2.1 Officer-in-Charge (OIC)	9/18/2025
9	[redacted]	Removed the Nuclear Technical Specialist position. Changed "Electric Distribution Operations Branch" to "Electric Distribution Branch". Changed "Electric Transmission Operations Branch" to "Electric Transmission Branch".	11/25/2025
9.7	[redacted]	Updated content to current configuration and activities.	Various
12	[redacted]	Removed content on the Demobilization Unit. Made corrections and updated language.	11/25/2025
Appendix A - A.2	[redacted]	Community Resource Centers (CRCs) – Updated the verbiage to align with the PSPS Annex.	9/18/2025
Appendix C and E	[redacted]	Updated content.	Various
Appendix H	[redacted]	Added "Assignment of Functional Responsibilities" to support the requirements of the Emergency Management Accreditation Program (EMAP).	9/30/2025
9 (Figure 9-1)	[redacted]	Changed "Generation Branch" to "Power Generation Branch". Removed DCPP Unit.	3/28/25

Recission Log

Document Number	Title
NA	NA

Reference Documents

Document Number	Title
EMER-01	Emergency Preparedness and Response Policy
EMER-2001S	Company Emergency Response Plans Standard

Document Number	Title
EMER-2003S	Enterprise After-Action Report (AAR) Standard
EMER-2004S	Emergency Response Records and Documentation Management Standard
EMER-2006M	EOC On-Call Standard
EMER-2007S	Emergency Response Posture Standard
EMER-2008M	Emergency Response Training Program
EMER-2009M	Emergency Recovery Program Manual
EMER-2502M	Integrated Preparedness Plan (IPP)
EMER-3001M-Att01	Cal OES Regional Contacts
EMER-3001M-Att02	County Government Contacts
EMER-3005S	PG&E's Emergency Field Site Request and Approval Standard
EMER-3105M	Wildfire Annex
EMER-3106M-01	Access and Functional Needs (AFN) Plan
EMER-4002S	Public Safety Specialist Standard
EMER-4010S	Mobile Command Vehicle Standard
EMER-4501S	Electric Incident Management Team Framework Standard
EMER-4510S	Operations Emergency Center (OEC) Activation Requirements
EMER-5001S	Power Generation Incident Management Team Framework Standard
EMER-5004S	Gas Incident Management Team Framework
SAFE-5000M	PG&E Safety Excellence Management System Manual
RISK-5001S	Enterprise and Operational Risk Management Standard
RISK-5001P-01	Enterprise and Operational Risk Management Procedure
RISK-5001P-02	Maintaining the Corporate Risk Register
EMER-7001S	Enhanced Customer and Community Support During All Hazards Standard
EMER-7001P-02	CSU Ford Transit Operating Procedure
EMER-7001P-03	All Hazards Life Agent Outbound Call Procedure
EMER-7001P-04	All Hazards Access and Functional Needs (AFN) Customer Support Procedure
EMER-7001P-05	All Hazards Community Resource Center (CRC) Deployment Procedures
EMER-7001P-06	All Hazard Medical Baseline Customer Doorbell Rings Procedure
EMER-4102S	Preventing and Mitigating Fires While Performing PG&E Work
TD-2060S	Emergency Electric Corrective Documentation Standard
TD-2060P-01	Routine Emergency – Emergency Estimate Required
TD-2060P-01-F01	Electric Emergency Construction Package

Document Number	Title
TD-4413P-01	Procedure for Reportable Gas Incidents
GO 166	Standards of Operation, Reliability and Safety During Emergencies and Disasters.
GO 112-F	State of California Rules Governing Design, Construction, Testing Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems

Document Owner

Name	Title
[redacted]	Manager, Emergency Preparedness and Response, Planning

Document Preparers

Name	Title
[redacted]	Emergency Management Specialist, Senior
[redacted]	Emergency Management Specialist, Expert
[redacted]	Technical Writer, Expert

Document Reviewers

Department	Leadership Team	Review Team
Liaison & Regulatory Operations & Engagement	[redacted]	[redacted]
Aviation Services	[redacted]	[redacted]
CAP Specialists	[redacted]	
Community Relations	[redacted]	[redacted]
Wildfire, Emergency & Operations, Wildfire Mitigation	[redacted]	Hitesh Bhatt
Enterprise Health and Safety	[redacted]	[redacted]
Operational Safety	[redacted]	[redacted]
Corporate Security	[redacted]	[redacted]
Customer Emergency Planning and Operations	[redacted]	[redacted]
Cybersecurity	[redacted]	[redacted]
Electric Core Programs	[redacted]	[redacted]

Department	Leadership Team	Review Team
Electric Distribution System Operations	[redacted]	[redacted]
Electric Transmission System Operations	[redacted]	[redacted]
Wildfire, Emergency & Operations, Emergency Field Operations	[redacted]	[redacted]
Electric Incident Investigation	[redacted]	[redacted]
Wildfire, Emergency & Operations, Emergency Preparedness and Response	[redacted]	[redacted]
Energy Policy and Procurement (EPP)	[redacted]	[redacted]
Information and Records Governance	[redacted]	[redacted]
Finance	[redacted]	[redacted]
Gas System Operations	[redacted]	[redacted]
Generation Asset Strategy	[redacted]	[redacted]
Diablo Canyon Power Plant	[redacted]	[redacted]
Geosciences	[redacted]	[redacted]
GIS Analytics	[redacted]	[redacted]
Government Relations	[redacted]	[redacted]
Information Technology	[redacted]	[redacted]

Department	Leadership Team	Review Team
Law	[redacted]	[redacted]
Corporate Communications	[redacted]	[redacted]
Meteorology	[redacted]	[redacted]
Power Generation	[redacted]	[redacted]
Public Safety Power Shutoff (PSPS)	[redacted]	[redacted]
Public Safety Specialist Program	[redacted]	[redacted]
Risk Management	[redacted]	[redacted]
Service Planning & Design (SP&D)	[redacted]	[redacted]
Vegetation Management	[redacted]	[redacted]
Hazard Awareness & Warning Center	[redacted]	[redacted]

Document Approvers

Name	Title
Angie Gibson	Vice President, Emergency Preparedness and Response
[redacted]	Sr. Director, EP&R Emergency Response
[redacted]	Director, EP&R Strategy and Execution

Document Control

Emergency Preparedness and Response (EP&R) Strategy & Execution maintains the Gas Annex to the Company Emergency Response Plan (CERP). This section records the revisions made to the Gas Annex, the people responsible for its preparation, maintenance, and update, and signature authorities for Plan approval.

Change Record

The following table shows changes made to the plan since the last revision (Version 14.0).

Section	Person Responsible for Revision	Change	Date
Throughout	[redacted]	Aligned document with EMER-2001S-Att.02, CERP-Annex Master Template.	Multiple
Throughout	[redacted]	Changed GERP to Gas Annex to the CERP. Removed references to EMER-6010S GERP Training, Exercise, and Evaluation, which is obsolete. EP&R has a training manual for all emergency response coworkers (EMER-2008M).	7/1/25
1.3	[redacted]	Added IMT to level 2 incident escalations.	7/21/25
1.3.1	[redacted]	Moved subsection 3.2.1 “Flexible Emergency Response for the Incident Commander” content under Assumptions and Hazards section. Added a reference to TRAN-2001S Drug and Alcohol Testing Requirements.	7/9/25
1.3.2	[redacted]	Added ‘Branch’ to SEMS/ICS terms and definitions.	7/16/25
1.3.2	[redacted]	Moved subsection 1.2.1 “Incident Command System Terms and Definitions” content to subsection 1.4, Regulations and Authorities.	7/1/25
1.3.3	D[redacted]	Added Gas Operator Qualifications subsection.	7/8/25

Section	Person Responsible for Revision	Change	Date
1.4.1	[redacted]	Added Gas Operator Qualification content based on July 15, 2025, CERP Gas Annex, Q3 Status Update & Review Meeting, highlighting abnormal operating conditions and GPOM qualification requirements. Added abnormal operation conditions description.	7/16/25
1.4.2	[redacted]	Added reference to OG-4008, Guide to Operator Qualifications for OQ tasks.	7/17/25
2	[redacted]	Moved subsection 1.3 incident level content to section 2, Emergency Organizations, Facilities, and Responsibilities.	7/1/25
2.1	[redacted]	Moved subsection 2.5, Emergency Management, under section 2, Emergency Organizations, Facilities, and Responsibilities.	7/10/25
2.1	[redacted]	Rewrote subsection consistent with EMER-2001S-Att.02, CERP-Annex Master Template to reflect gas emergency operations as a function rather than a PG&E organizational component.	8/11/25
2.1.1	[redacted]	Changed IMT deployment threshold from level 3 to level 2 incident.	7/16/25
2.1.2	[redacted]	Noted GEC and IMT(s) may be activated at level 3 and will be activated at level 4 and 5.	7/21/25
2.1.2	[redacted]	Added yellow highlight to IMT activation for levels 2-5 incident management.	8/1/25
2.4	[redacted]	Added Gas Integrity Management Roles and Responsibilities content consistent with the Gas Integrity Management Storm Playbook.	7/1/25
2.5.2	[redacted]	Added IMT description consistent with CERP subsection 2.10.	7/7/25
2.6.3	[redacted]	Created a new example of integrated GEC/IMT organization subsection.	9/9/25

Section	Person Responsible for Revision	Change	Date
2.7	[redacted]	Removed ICP reference.	8/14/25
2.7	[redacted]	Removed MCV reference.	9/5/25
2.8	[redacted]	Created ICP subsection.	9/9/25
2.9	[redacted]	Created new Emergency Equipment subsection with FORTS and MCV capability descriptions.	9/5/25
3.2	[redacted]	Removed duplicative CERP section 5 ICS-Based Incident/Event Management content.	7/9/25
3.2.1	[redacted]	Removed Dual Commodity and Response (GEC and EOC) content in lieu of CERP Internal Communication and Unified Command content, subsections 4.2 and 7.3.2.	7/9/25
3.2.2	[redacted]	Added make safe gas transmission pipeline exclusion zone content per CAP items 129329501 and 129746687.	1/6/25
3.2.2	[redacted]	Updated Resource Management subsection to align with EMER-3001M-01	7/9/25
3.2.2	[redacted]	Updated MA protocol to specify EP&R VP and SE Director request routing.	9/12/25
3.2.3	[redacted]	Added Mutual Assistance subsection referencing CUEA, WRMAG, and AGA MA content aligned with EMER-3001M-02.	7/9/25
3.2.3	[redacted]	Added reference to McDonald Island Levee Breach Response Operating Plan.	8/6/25
5.1	[redacted]	Replaced GEP with EFO.	8/1/25
6.1	[redacted]	Added reference to EMER-2004S Emergency Response Records and Documentation Standard for EOC level incident activations.	9/16/25

Section	Person Responsible for Revision	Change	Date
Figure 2-2	[redacted]	Removed IST.	7/16/25
Figure 2-2	[redacted]	Noted IMT may be activated upon request.	8/4/25
Figure 2-3	[redacted]	Added IMT operational level graphic.	7/7/25
Figure 2-5	[redacted]	Added Branch Directors and Group/Division Supervisors to Operations Section.	8/4/25
Figure 2-6	[redacted]	Added "…as needed" to Deputy Engineering, Mapping and Engineering SME positions.	8/4/25
Table 1-1	[redacted]	Updated Cold Water Communication process link.	1/7/25
Table 2-1	[redacted]	Added IMT level 4-5 activations.	8/1/25
Table 2-1	[redacted]	Note potential IMT level 2 activation.	8/4/25
Appendix A	[redacted]	Added GEP (Gas Emergency Preparedness) to acronyms.	8/4/25
Appendix B.4	[redacted]	Added EMER-3101M-02 initial damage assessment process reference.	8/22/25
Appendix B.4	[redacted]	Added Tsunami hazard mitigation and assessment reference.	8/13/25
Appendix C	[redacted]	Updated ICS form references and links to meet CAP item 131040303-0002 requirements, to include EOC SharePoint links for 206, 208 and 215A forms.	4/14/25
Appendix D	[redacted]	Relocated CUEA, WRMAG, and AGA MA content to subsection 3.2.3.	7/17/25
Appendix E, Table 7-1	[redacted]	Added US Chemical Safety Board to Federal and State reporting contacts.	8/7/25

Section	Person Responsible for Revision	Change	Date
Appendix F	[redacted]	Appended McDonald Island Levee Breach Response Operating Plan.	8/6/25

Recission Log

Document Number	Title
NA	NA

Reference Documents

Document Number	Title
EMER-01	*Emergency Preparedness & Response Policy*
EMER-1001S	*Business Continuity Planning, Training, Exercise, and Improvement Planning Standard*
EMER-2001S	*Company Emergency Operations Plans Standard*
EMER-2001S-F01	*Change Request Form*
EMER-2004S	*Emergency Response Records and Documentation Standard*
EMER-3001M	*Company Emergency Response Plan (CERP)*
EMER-3001M-01	*Resource Management Process*
EMER-3001M-02	*Mutual Assistance Playbook*
EMER-3005M	*CERP Logistics Annex*
EMER-3101M	*CERP Earthquake Annex*
EMER-3101M-02	*Gas Integrity Management Earthquake Playbook*
EMER-3102M	*CERP Cybersecurity Annex*
EMER-4010S	*MCV standard*
EMER-4510S	*Operations Emergency Center (OEC) Activation Requirements*
EMER-6010S	*Gas Emergency Response Plan Training*
EMER-7001S	*Enhanced Customer and Community Support During All Hazards Standard*

Document Number	Title
EMER-7001P-05	*All-Hazards Community Resource Center (CRC) Deployment Procedure*
TD-4110S	*Gas Leak Survey and Detection Program*
TD-4008S	*Operator Qualification Program Requirements*
TD-4008S -Att-01	*Gas Operator Qualification Abnormal Operating Conditions (AOC)*
OG-4008	*Guide to Operator Qualifications*
TD-4110S	*Gas Leak Survey and Detection Program*
TD-4110P-01	*Leak Survey Process*
TD-4110P-09	*Leak Grading and Response*
TD-4411P-04	*Assessing and Working with Hazardous/Gaseous Atmosphere*
TD-4127P-05	*Criteria for Identifying High Consequence Areas*
TD-4412P-07	*Patrolling Gas Pipelines*
TD-4412P-07-JA01	*Identification of Common Geohazards*
TD-4435S	*Gas System Curtailment Requirements*
TD-4435P-01	*Extreme Weather-Related Gas Service Curtailment Procedure*
TD-4814S	*Gas Transmission Heavy Rainfall Response Standard*
TD-4814P-01	*Gas Transmission Heavy Rainfall Preparation and Response*
TD-4820P-01	*Make-Safe Actions for Steel Transmission Pipelines*
TD-5801S	*Pipeline Public Awareness Program*
TD-6100P-02	*Gas Leak and Odor Investigations*
TD-6100P-03	*Major Gas Event Response: Fire, Explosion, and Gas Pipeline Rupture*
SAFE-5000M	*PG&E Safety Excellence Management System Manual*
	PG&E Gas Safety Plan
TRAN-2001S	*Drug and Alcohol Testing Requirements*

Document Preparers

Name	Position
[redacted]	Emergency Management Supervisor, Emergency Field Operations

Name	Position
[redacted]	Emergency Management Specialist, Expert

Document Owner

Name	Position
Sally Romero	Senior Vice President, Gas Operations

Document Reviewers

Name	Position
[redacted]	Director, Gas Control
[redacted]	EP&R Strategy & Execution, Planning Manager
[redacted]	Gas Integrity Management Engineer, Expert
[redacted]	Expert Gas Program Manager
[redacted]	Expert Electric Emergency Management Specialist, Emergency Field Operations
[redacted]	Director, Gas Transmission Portfolio Management and Engineering
[redacted]	Gas Integrity Management Engineer, Principal
[redacted]	Gas Integrity Management Engineer, Senior
[redacted]	Director, Enterprise Information Governance
[redacted]	Gas System Supervisor, Gas Control Operations
[redacted]	Manager, Meteorology/Fire Sciences
[redacted]	Senior Engineer, Gas Facility Integrity Management Program (FIMP) Regulation Engineering
[redacted]	Expert Emergency Preparedness Coordinator, Emergency Field Operations
[redacted]	Manager, Emergency Management (EP&R SE Training)
[redacted]	Gas Control Operations Specialist, Senior
[redacted]	Supervisor, Gas Transmission Integrity Management Program (TIMP) Risk Management
[redacted]	Supervisor, Engineering Standards, Pipeline
[redacted]	Senior Director, Gas Facilities and Storage
[redacted]	Senior Manager, Emergency Management, Public Safety Specialist Program
[redacted]	Supply Chain Emergency Management Specialist, Principal
[redacted]	Principal Engineer, Gas Facility Integrity Management Program (FIMP)
[redacted]	Supervisor, Gas Transmission Clearance
[redacted]	Gas Program Manager, Principal
[redacted]	Geosciences Consultant, Expert
[redacted]	Expert Emergency Preparedness Coordinator, Emergency Field Operations

Name	Position
[redacted]	Manager, Emergency Operations Center (Logistics)
[redacted]	Principal, Geosciences Consultant
[redacted]	Regional Operations Specialist, Principal (Central Valley)
[redacted]	Senior Director, Gas T&D Portfolio Management & Engineering
[redacted]	Expert Emergency Preparedness Coordinator, Emergency Field Operations
[redacted]	Expert Gas Facility Engineer
[redacted]	Supervisor, Emergency Management, Emergency Field Operations
[redacted]	Senior Emergency Management Specialist
[redacted]	Principal Gas Engineer
[redacted]	Senior Director, Gas Transmission and Distribution
[redacted]	Supply Chain Emergency Management Specialist, Principal
[redacted]	Supervisor, Emergency Management, Emergency Field Operations
[redacted]	Supervisor, Environmental

Document Approvers

Name	Position
[redacted]	Senior Director, Gas System Operations
Sally Romero	Senior Vice President, Gas Operations

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 4

CHANGE LOG FOR 2026 GAS SAFETY PLAN

Attachment 4

2025 Gas Safety Plan → 2026 Gas Safety Plan

Section Number(s)	Section Title	Change Summary (2025 → 2026)
I; I.1	Introduction/Structure of the Gas Safety Plan	Reporting period updated to reflect work performed during 2025; system description updated to reflect current asset inventory, operational scope, and organizational structure to ensure alignment with the reporting year and regulatory review expectations.
I.2	PG&E's True North Strategy	Clarified and strengthened alignment between Gas "Plans on a Page" and enterprise True North priorities, establishing a clearer line of sight between Gas safety activities, enterprise strategy, and safety-related performance outcomes.
I.3	PG&E Safety Excellence Management System (PSEMS)	Documented transition from initial enterprise adoption (2025 Plan) to full Gas implementation, including entry into a maturity-based assessment cycle; formally documented retirement of the Gas-specific MOC standard and alignment with the enterprise MOC framework to ensure consistency and governance clarity.
I.3.a–b	Independent Third-Party Certification/SMS Maturity	Added 2025 LRQA audit results, findings, and opportunities for improvement; updated maturity discussion to reflect the PSMS maturity model and annual, risk-prioritized element reviews supporting continuous improvement and external verification.
I.4	Public Safety	Updated public safety metrics and performance outcomes for in-line inspection, dig-ins, emergency response, and strength testing based on 2025 results, supporting transparent reporting of system performance and risk mitigation effectiveness.
I.5	Workforce Safety	Expanded discussion of DART trends, Serious Injury and Fatality (SIF) classification using the EEI SCL model, corrective action effectiveness reviews, and targeted injury reduction actions to strengthen workforce risk management and prevention focus.

Section Number(s)	Section Title	Change Summary (2025 → 2026)
II (all)	Safety Culture	Added results of the 2025 NSC Safety Culture Barometer Survey; expanded discussion of OSCC Areas for Improvement, Human Performance governance enhancements, and Safety Culture Village growth to demonstrate ongoing measurement and improvement of safety culture.
II.1	Corrective Action Program (CAP)	Expanded CAP metrics, dashboard maturity, and trending analytics (including behavioral attributes), with increased emphasis on Quality Closure Reviews to support timely, effective, and durable corrective actions.
III	Process Safety	Clarified integration of Process Safety within the enterprise PSEMS framework; expanded coverage of PHAs, PSSRs, MOC improvements, PSI dashboard maturity, and near-miss integration to enhance hazard identification, risk control, and learning.
IV	Gas Leak Abatement Plan	Included the 2026–2027 Leak Abatement Compliance Plan; updated methane reduction results and expanded component-level emissions methodology to support regulatory compliance, emissions transparency, and continuous reduction strategies.
V (overall)	Asset Management	Refreshed asset management discussion to reflect ISO 55001:2024 principles; updated asset family progress and risk treatment outcomes to demonstrate alignment with asset management best practices and risk-informed decision-making.
V.2.c; V.5.g	Transmission Pipe / In-Line Inspection	Documented completion of TransDef implementation; updated piggability percentages and expanded discussion of non-traditional in-line inspection advancements to support system integrity assessment coverage.
V.4; V.5	Measurement & Control/ Overpressure	Updated overpressure event statistics and mitigation progress; clarified impacts of GRC funding decisions on the long-term overpressure elimination roadmap while maintaining interim risk mitigation measures and operational safety controls.
V.5.c–f	Distribution Pipeline Replacement Programs	Updated replacement mileage through 2025 and clarified interaction with alternative energy and electrification strategies while continuing to prioritize safety-driven replacement risk criteria.

Section Number(s)	Section Title	Change Summary (2025 → 2026)
V.2.h	Data Asset Family	Expanded detail on data stewardship maturity, governance integration, analytics platform development, and data quality controls to support reliable risk analysis, reporting, and decision-making.
V.7 (all)	Emergency Preparedness & Response	Expanded coverage of live action drills, Incident Management Team activations, cyber-physical exercises, and coordination with first responders to strengthen preparedness, response capability, and interagency coordination.
VI.2	Workforce Training	Documented strategic shift from primarily web-based training to hands-on, skills-based refresher training; highlighted new training facilities and field-realistic assets supporting workforce competency and operational readiness.
VII	Compliance Framework	Updated compliance maturity model narrative reflecting a pause in formal assessments and a planned limited-scope assessment in 2026; expanded discussion of supportive controls and governance to maintain compliance oversight during the interim period.
VIII.1	Quality Management	Significantly expanded Quality Management System detail, including layered defense model, QC/QA/QV statistics, and program coverage to demonstrate enhanced assurance and verification activities compared to the prior year.
VIII.3	Research, Development & Demonstration (RD&D)	Expanded discussion of methane monitoring pilots, vacuum purge technology, SPADE system deployment, and non-intrusive inspection technologies to support innovation in safety, emissions reduction, and integrity assessment.
VIII.4	Benchmarking and Best Practices	Added use of AI-based regulatory benchmarking tools and expanded peer utility engagement and industry collaboration to support continuous improvement and adoption of best practices.

VERIFICATION

We, the undersigned, state:

We are officers of PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, and are authorized to make this verification for and on behalf of said corporation, and we make this verification for that reason. We have read the foregoing 2026 Gas Safety Plan, and are informed and believe the matters therein are true and, on that ground, we allege that the matters stated therein are true.

We declare under penalty of perjury under the laws of the state of California that the foregoing is true and correct.

Executed at San Ramon, California, on March 13, 2026.

Sally Romero

Sally Romero
SENIOR VICE PRESIDENT
GAS TRANSMISSION & DISTRIBUTION
PACIFIC GAS AND ELECTRIC COMPANY

Austin Hastings
VICE PRESIDENT
GAS ENGINEERING
PACIFIC GAS AND ELECTRIC COMPANY