Pacific Gas and Electric Company®

PUBLIC VERSION

2020 GAS SAFETY PLAN

MARCH 16, 2020

Pacific Gas and Electric Company®

March 16, 2020

Dear Reader,

It is our fundamental responsibility to design, build, maintain, and operate our gas systems to keep customers and communities safe. The 2020 Gas Safety Plan ("Plan")[1] provides a high-level view of both the work we accomplished in 2019, and our plan moving forward to achieve our goals. The Plan continues to build upon the framework PG&E set forth in 2016 and strives to present important Gas Operations information in a manner that is accessible and clear to a broad audience.

PG&E's 2020 Gas Safety Plan includes several aspects that have expanded since the 2019 Plan. First, the 2020 Plan includes an expanded discussion of efforts taken to improve the Safety Culture through partnerships with Gas Leadership, Grassroots Safety Teams and the Labor Unions. In 2019, Gas Safety focused on preventing and reducing employee injuries, promoting healing and return to work and ensuring quality and appropriate medical care for PG&E's employees. Second, PG&E expands upon its discussion of PG&E's Corrective Action Program (CAP) in Gas. This program is an integral part of our safety culture as it provides a mechanism for employees to speak-up and report issues or ideas related to gas assets and processes as well as tracks actions taken to address such issues, some of which include conducting cause evaluations. Finally, the 2020 Plan discusses the third-party assessment of Gas Operations' compliance with the intent of API Recommended Practice 754, Process Safety Performance Indicators, in so far as it meets its business operations, demonstrating a commitment to incident prevention.

In compliance with the Leak Abatement Order Instituting Rulemaking Decision (D.) 17-06-015, a complete copy of PG&E's 2020 Leak Abatement Compliance Plan is included in Attachment 1. This biennial plan describes PG&E's application of the 26 Best Practices to reduce greenhouse gas emissions and PG&E's plan to reach goals of reducing emissions by 20 percent and 40 percent below 2015 baseline levels by 2025 and 2030, respectively.

While we have made progress in key safety areas, we realize there is more to do to demonstrate our commitment and progress towards Gas Safety Excellence. PG&E remains focused and dedicated to becoming the safest, most reliable gas utility in the United States.

Christine Cowsert
Vice President, Gas Operations
Asset Management and System Operations
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.

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I. INTRODUCTION

Pacific Gas and Electric Company (PG&E or the Company or the Utility) works every day to safely transport natural gas under pressure through approximately 6,600 miles of transmission pipelines, 43,000 miles of gas distribution pipelines, and 4.6 million meters. The PG&E natural gas system serves millions of Californians from Eureka in the North to Bakersfield in the South, and from the Pacific Ocean in the west to the Sierra Nevada in the east. PG&E’s employees work around the clock, 365 days a year to keep the public, customers, contractors, and employees safe. PG&E’s mission is to safely and reliably deliver affordable and clean energy to our customers and communities every single day, while building the energy network of tomorrow.

While there is more work to do to achieve PG&E’s mission, PG&E’s Gas Safety Plan provides a view into the safety activities PG&E pursues every day and highlights the specific safety work in 2019. PG&E annually reviews and updates its Gas Safety Plan in accordance with General Order 112-F Section 123.2(k), and Public Utilities Code Sections 961 and 963.[1] Figure 1 provides a summary of PG&E’s performance in key areas.

Gas Operations Safety Improvements

Gas Operations progress since 2010 demonstrate our commitment to becoming the safest, most reliable gas company in the country.

GAS ODOR RESPONSE TIMES	2010	2019
Average response time in minutes	33.3	20.8
Percent response within 60 minutes	94.4%	99.6%
SCADA VISIBILITY AND CONTROL POINTS		
Transmission pressures and flows	1,300	2,907
Transmission control points	870	1,953
Distribution pressures and flows	290	4,314
LEAK BACKLOG		
Grade 2 open leak average duration (Target: 150 days)		96 days
DIG-IN REDUCTION		
Third party gas dig-ins/1,000 USA tickets	3.5	1.04

GAS TRANSMISSION	2010	2011-19
Miles of pipeline replaced	9	>269
Miles of pipeline strength tested	0	>1,495
Miles of pipeline made piggable	130	>1,316
Automated valves installed	0	360
GAS DISTRIBUTION		
Miles of main replaced[1]	27	>863

SINCE 2011 PG&E HAS ALSO

- Completed GPS survey for 100% of the accessible transmission pipeline system using highly precise mapping tools
- Opened a state-of-the-art Gas Control Center in San Ramon, California
- Opened a world-class Gas Safety Academy located in Winters, California
- Opened the Center for Gas Safety and Innovation located in Dublin, California

Certifications received for gas operations:

In 2014, PG&E became one of the first utilities ever to earn two of the highest internationally recognized asset management certifications—the International Organization for Standardization (ISO) 55001 and Publicly Available Specification (PAS) 55-1.

- Gas Operations was recertified for both of these standards in 2017 and, in 2018 to 2019, Lloyd's Register confirmed Gas Operations' continued certification to the PAS 55/ISO 55001 standards for best-in-class asset management.

In 2015, PG&E became the first company in the U.S. to receive compliance for the industry standard on pipeline safety management systems, the American Petroleum Institute Recommended Practice (API RP) 1173.

- In November 2018, PG&E Gas Operations was successfully recertified as compliant with API 1173. In November 2019, Lloyd's Register confirmed Gas Operations' continued compliance with API 1173.
- In November 2019, PG&E Gas Operations was certified as compliant with API RP 754, Process Safety Performance Indicators, in so far as it meets its business operations.

[1] In 2014 all known remaining cast-iron pipe was decommissioned.

Figure 1 – Key Gas Performance Metrics

1. STRUCTURE OF THE GAS SAFETY PLAN

The 2020 Gas Safety Plan (Plan) reports on the progress PG&E has made on its goal to become the safest, most reliable gas company in the United States (U.S.), and details the work performed in 2019. The Plan reiterates PG&E's commitment, mission, and vision to safely and reliably deliver affordable and clean energy to our customers and communities. In alignment with California's regulatory framework,[2] 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.

The following sections of the Plan provide more information on how PG&E is achieving Gas Safety Excellence, and include updates on the Company's safety goals and commitments to public, customer, employee, and contractor safety.

- **Gas Safety Excellence Management System:** A safety management system provides the framework and structure to drive operational excellence to create industry-leading safety and reliability performance across the organization. It is a systematic process to protect, manage, and improve performance in dimensions of safety that are critical to reducing risks. This section describes PG&E Gas Operations' safety management system that permeates every aspect of gas operations known as the "GSEMS."
- **Safety Culture, Process Safety, and Asset Management:** Safety culture, process safety, and asset management together form the foundation of Gas Safety Excellence. These sections review how PG&E manages risk—both the inherent risk of the assets *and* the risk of working on those assets safely. This section describes how the Company identifies risk, prioritizes risks and then works to mitigate them, highlighting the three major categories of gas system risk the Company manages: loss of containment, loss of gas supply, and inadequate emergency response.
- **Workforce and Compliance Framework:** These sections review how PG&E qualifies, trains, and engages the workforce to mitigate risk by working on assets safely and performing work right the first time. These sections include information about PG&E's workforce training and qualifications programs, and how PG&E achieves compliance.
- **Continuous Improvement:** This section presents PG&E's efforts to continuously improve processes and procedures.

2. Gas Safety Excellence Management System

Gas Safety Excellence is demonstrated by:

- Putting ***SAFETY*** and people at the heart of everything
- Investing in the ***RELIABILITY*** and integrity of PG&E's gas system
- Continuously improving the effectiveness and ***AFFORDABILITY*** of PG&E's processes
- Supporting emissions reduction and working to advance PG&E's comprehensive ***CLEAN*** energy goals

Figure 2 – PG&E Gas Safety Excellence Management System

The GSEMS is PG&E Gas Operations' safety management system developed to achieve the vision of becoming the safest, most reliable, affordable, and clean gas utility in the nation. This safety management system provides the structure to systematically manage and maintain operational excellence in asset management, safety culture, and process safety, with a commitment to continuous improvement and in compliance with best-in-class industry standards. The GSEMS consists of the following sixteen elements that focus on supporting performance management to achieve our goals:

1. Leadership Commitment, Accountability and Employee Participation
2. Asset Management and Life Cycle Planning
3. Risk Assessment and Management
4. Incident Investigation and Corrective Action(s)
5. Compliance with Legal, Regulatory and other Operational Requirements
6. Operational Planning and Control(s)
7. Communication and Stakeholder Engagement
8. Information, Documentation and Records Management
9. Contractor Management and Third Party Services
10. Training, Competency and Awareness
11. Management of Change
12. Monitoring and Measurement
13. Emergency Preparedness and Response
14. Auditing
15. Quality Management and Continuous Improvement
16. Management Review

PG&E's GSEMS strives to enable employees to do their work right the first time to deliver high-value, quality services.

3. PG&E's Goals

Gas Operations annual strategic goals are developed through the "Line of Sight" process. This process incorporates the Company's focus areas and the updated plans or results from the Quarterly Business Review (QBR) process to develop three to five year objectives, annual objectives, and initiatives that are linked. The Line of Sight goals, as well as new targets for the ongoing work, are incorporated into the QBR process. "Line of Sight" goals in 2019 aligned business strategy with six key themes: Safe, Reliable, Affordable, Customer, People, and Compliance. This planning process results in strategic goals to drive action throughout the business. Related goals and metrics cascade throughout the organization to provide each employee a line of sight to how their actions support PG&E's vision. These items are discussed in more detail throughout this update.

a) Public Safety

In 2019, PG&E had success in three primary safety areas: In-Line Inspections (ILI), Third-Party Dig-Ins, and Leak Repair Effectiveness.

- **In-Line Inspection:** In 2019, PG&E increased piggability to roughly 36 percent of the approximately 6,600 miles of the Gas Transmission system. PG&E plans to upgrade approximately two-thirds of its transmission system (about 4,100 miles) to accept ILI tools by the end of 2029.
- **Third Party Dig-In:** In 2019, PG&E experienced 1.04 dig-ins per 1,000 Underground Service Alert (USA) tickets, out-performing its 2019 target of 1.23 dig-ins per 1,000 USA tickets.
- **Leak Repair Effectiveness**: In 2019, PG&E's Grade 2 leaks remained open an average of 96 days, exceeding the target of 150 days.

b) Workforce Safety

PG&E's goal is to provide a safe and secure workplace where each employee is appropriately trained and equipped to complete their work right the first time. PG&E's goal is zero worker safety incidents.

To achieve its goal, PG&E designed the One PG&E Occupational Health and Safety Plan (One PG&E Health & Safety Plan), in part, using an analysis of the leading drivers of injury to determine plan elements. The One PG&E Health & Safety Plan is developed by Corporate Safety and Health with input from all lines of business, and is a multi-year plan focused on areas where injuries and incidents are occurring. Each line of business (LOB) adopts the initiatives and implements the practices contained therein throughout the year. The 2019 One PG&E Health & Safety Plan focused on eight initiatives relating to Musculoskeletal Disorders, Motor Vehicle Safety, Health and Wellness, Safety Management Systems, Serious Injury or Fatality (SIF), Contractor Safety, Injury Management, and Supervisor Leadership Development.

In 2019, Gas Operations employees were involved in 33 Lost Time Injuries, which was equal to 2018. In 2019, the California Occupational Safety and Health Administration recordable rate decreased by approximately three percent. This may have resulted from PG&E's increased emphasis on the 24 hour, seven days a week Nurse Care Line and early reporting. In 2019, 80.8 percent of employees who called the Nurse Care Line reported discomfort or an injury within 24 hours, exceeding the target of 72 percent. This renewed emphasis on early intervention has had a positive effect on workforce injuries. Based on the review of our data, PG&E believes that speaking to a healthcare professional about an injury or illness within 24 hours contributes greatly to the reduced severity and recovery time of an injury or illness. Figure 3 illustrates the downward trend in severity of incidents. Through consistent application of reporting and preventative efforts, the serious lost time injuries have begun to follow the OSHA recordable curve and shows improvement.

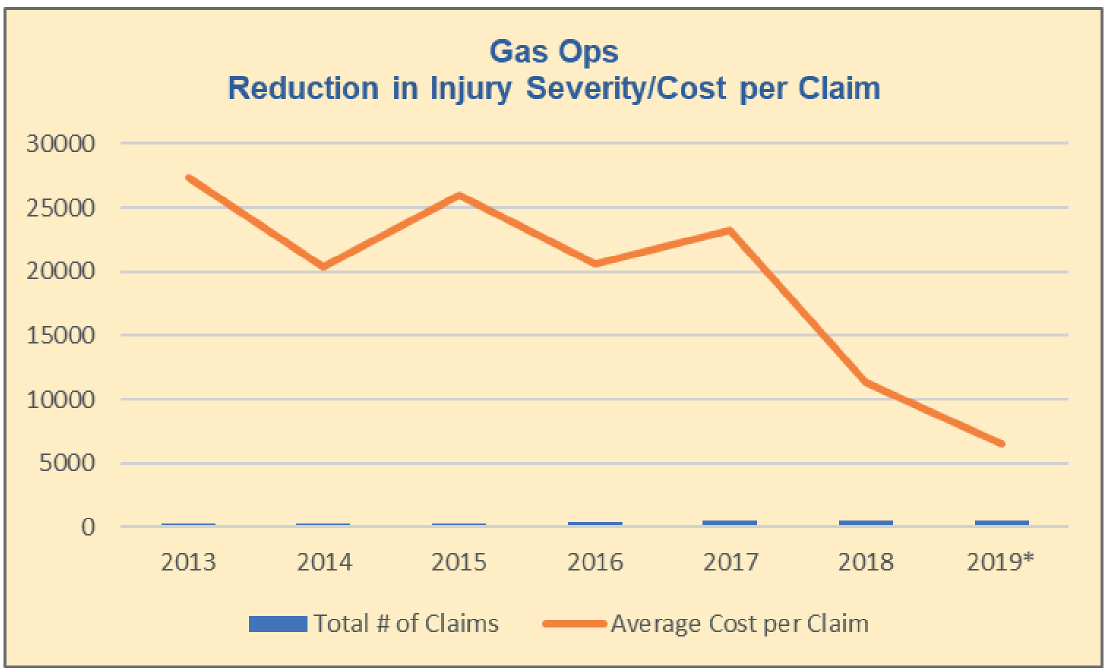


Figure 3 – Reduction in Injury Severity

In 2019, Gas Operations had five safety incidents that had the potential to cause a SIF. A SIF review team, composed of department representatives, evaluates the incident to determine if there was a high probability that the hazard/operational failure would result in life-threatening or life-altering injury. Once an incident is determined to have a potential to be a SIF, 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 reoccurrence. Upon completion of the internal investigation, a written report is presented to the Corrective Action Review Board to evaluate and accept the corrective actions. A third party then evaluates and scores the quality of the corrective actions. PG&E added additional evaluation measures, such as Timely Corrective Action Completion and Quality of Corrective Actions, to focus on the quality and timely closure of corrective actions from SIF investigations. In 2019, Gas Operations completed 100 percent of the corrective actions in a timely manner compared to 95 percent in 2018. For 2019, the SIF quality of Corrective Actions score was 13.2, exceeding the target of 12.

Another area of focus continues to be Motor Vehicle Safety. In 2019, there were twelve Serious Preventable Motor Vehicle Incidents (SPMVI), a 33 percent increase from 2018. In 2017, the Company installed an in-cab coaching technology to over 2,600 gas vehicles and developed a metric to score employees' driving behaviors. The technology alerts drivers when their vehicle accelerates too fast or brakes too hard. These are both leading indicators to incidents that have the potential to cause extensive damage or a SPMVI. This ratio yields a Safe Driving Rate in which a lower ratio is preferred. In 2018, Gas Operations scored a Safe Driving Rate of 6.2. In 2019, Gas Operations finished with a Safe Driving Rate of 4.9, a 21 percent reduction from the previous year.

Figure 4 – Examples of PG&E Gas Motor Vehicles

As the Company continues to improve its motor vehicle safety program, conduct more driver observations, evaluate backing sensor technology, enhance driver safety training, and promote awareness campaigns, PG&E is optimistic that it will continue to reduce OSHA recordable injuries, Days Away, Restricted, and Transferred rate and motor vehicle incidents.

4. 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 can include those who submit Corrective Action Program (CAP) items that can decrease the risk of fatalities or injuries, damage to assets, reliability issues, and environmental impact. Any employee can submit an Eagle Eye nomination.

- **Caught Being Safe** – 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 One PG&E Health & Safety Plan. As a token of appreciation, the employees who nominate them are also eligible to receive rewards and recognition. In 2019, 80 Caught Being Safe nominations were submitted and 96 people were recognized.
- **Process Safety Ambassador Award** – This award recognizes teams and individuals for going above and beyond in applying the keys to Process Safety to their work, such as having a questioning attitude, taking time to evaluate the hazards prior to starting a task, and reporting a CAP.

5. Natural Gas Leak Abatement Compliance Plan

On January 22, 2015, the California Public Utilities Commission (CPUC or Commission) opened 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 greenhouse gas (GHG) emissions. In the June 16, 2017 Phase 1 Leak Abatement OIR Decision (D.) 17-06-015, the Commission adopted 26 Best Practices related to natural gas leak abatement. PG&E's gas leak abatement program includes annual methane emission tracking reporting, and a biennial best practice compliance plan submission. Attachment 1 to this plan is the second biennial Leak Abatement Compliance Plan prepared in accordance with the Commission's decision.

II. Safety Culture

PG&E's commitment to strengthening our safety culture and performance is reinforced in the Company's Mission, Vision, and Culture. Figure 5 illustrates PG&E's mission, vision and culture statements that are the foundation of our decision-making process.

Gas Operations Safety and Leadership worked to improve workforce safety through building a culture focused on the hearts and minds of our employees and building a deeper partnership between Gas Operations leadership, Grassroots Safety Teams and the Labor Unions. The goals of the partnership were to focus on preventing and reducing employee injuries, promoting healing and return to work; and ensuring quality and appropriate medical care for our employees.

In 2019, with leadership support, Gas Safety focused on preventing and reducing employee injuries, promoting healing and return to work, and ensuring quality and appropriate medical care for our employees.

Milestones in support of Gas Safety's focus included a benchmarking trip with a first quartile company with similar work and exposures, building safety at the source with Grassroots Peer and Lean reviews and safety assurance, developed a comprehensive Injury Prevention/ Management training and toolkit for leaders, an analysis on Nurse Care Line calls to learn and prevent similar incidents from recurring, on-going recognition of Gas employees when raising safety issues, front line supervisors in high risk areas support through on-site prevention specialists and field safety support, and supported warm up stretches during huddle sessions every morning.

Figure 5 – PG&E's Mission, Vision, and Culture Statements

The partnership has resulted in a tremendous improvement in different safety behaviors and shifting the culture, including the following:

- Improving supervisor engagement – over 200 Gas Leaders were trained on awareness and skills to prevent injuries, reduce the severity and manage an employee's injury and provided a comprehensive Injury Prevention toolkit.
- Problem solving sessions were created to address issues such as motor vehicle improvement, tool safety and process or procedure safety allowing for immediate sharing of lessons learned.
- The focus on early reporting and prevention contributed to the reduction in injury severity. The average cost of claims in Gas Operations has reduced by 79 percent since 2012.
- Increased Onsite Prevention Specialist (OPS) engagement and utilization in cities identified as having higher risks and exposures. The OPS focused on observing employee biomechanics, ergonomics and risk behaviors resulting in identification of corrective actions and recommendations. Gas Operations had a 35 percent OPS utilization rate with Central Coast (62 percent), Humboldt (58 percent) and Yosemite (47 percent) as the Top Three Divisions.
- Return to Work Program provides transitional, temporary work assignments (for up to six months) to employees whose restrictions cannot be accommodated within their base jobs. Ninety one Gas employees have been placed into task assignments since August 2017.
- Utilization of RSI Guard – Enabled set break/microbreak frequency to promote breaks, stretches and microbreak awareness to allow the employee to perform their job in a healthy and safe way. Gas Operations performed at 94 percent overall break compliance in 2019.

Gas Safety's 2019 focus provided Gas Operations with the awareness and tools to be successful beyond this initiative. Gas Leadership, in partnership with Grassroots Safety Teams and Labor Unions, will continue to reinforce PG&E's commitment to safety and encourage its employees to work safely. Gas Operations will continue to utilize Industrial Ergonomics to minimize hazards related to work equipment, environment, tools and processes through prioritization of frequency of activity by work type, looking for quick wins by changing out tools and sharing immediate lessons learned with others to reduce hazards.

As an organization, PG&E's ongoing focus is to influence behaviors to change by connecting with those that do the work, build/improve our Safety Culture through focusing on the hearts and minds of our employees, and continue to build a deeper partnership between Gas and Labor Unions to drive safety.

1. Employee Engagement

In 2019, PG&E continues to reinforce the various new initiatives to enhance employee engagement. These initiatives included: Lean Management, Operational Learning, Safety Leadership Development, and Leader in the Field.

Lean Management. In 2019, Gas Operations continued to support and reinforce the importance of "huddles" throughout the organization. Huddles are quick, structured conversations among team members that occur daily or several days a week. Huddles provide a platform for employees to speak up and raise issues, share resolutions and information, discuss progress on metrics and targets at each level, identify areas for improvement, align on priorities, and recognize individuals and/or teams for great work and successes. Separately, employees have designated time for Problem Solving sessions where roadblocks are identified and employees are given the opportunity to help develop a solution.

Lean Management also encourages leaders within Gas Operations to spend more time engaging with their employees directly. Leaders regularly visit locations where the work is occurring to meet employees, hear firsthand their thoughts on what is working well and where improvements are needed, and to observe the work being performed to see for themselves what opportunities for improvement exist.

Operational Learning. In addition to Lean Management, the Corporate Safety and Health organization and Gas Safety continue to partner on introducing key concepts and tools related to Operational Learning to many of the leaders and employees in Gas Operations. Operational Learning is a process that focuses on understanding the difference between how work is planned and how work is actually done. Operational Learning is a major initiative under the Safety Leadership Focus Area in the One PG&E Health & Safety Plan.

Learning Teams are another type of activity that supports Operational Learning concepts, as well as PG&E's Speak Up, Listen Up, and Follow Up culture. Corporate Safety and Health established Learning Teams as a result of benchmarking safety best practices across several different industries. Learning Teams are formed by gathering a group of front-line employees, led by a trained facilitator, to discuss how work is done and where gaps exist. As a group, the Learning Team identifies and understands strengths in a system, as well as opportunities for improvement. In 2019, Gas Operations Safety and Lean Management participated in Learning facilitation training. Gas Operations Safety co-facilitated one Learning Team regarding the In-Line Inspection Clearance process. The important cultural shift that comes from incorporating Operational Learning concepts is to move from a culture of blame to a culture of learning.

Safety Leadership Development. Beginning in 2017, the *Leading Forward: Safety Leadership* program was delivered to all operational leaders. The program included three workshops: Shaping a Safety Culture; Identifying and Controlling Exposure; and You Are Not Alone. In 2019, current leaders continued to sustain the program by having periodic discussions in which best practices, lessons learned and collaboration for solving issues occurred. A total of 67 leaders completed the program.

Leader in the Field. In July 2019, Leader in the Field was rolled out. Leaders—particularly those closest to our operational work—play an important role in supporting our company's focus on safety, meeting our commitments and de-risking the system. For this reason, field leaders' number one priority is to be in the field with their people, ensuring safety and quality at the source of the work we execute.

a) Corrective Action Program

The Corrective Action Program (CAP) is an integral part of our safety culture in Gas Operations. PG&E's continued use and support of the CAP demonstrates to our employees, our regulators, and our customers, that we have an unwavering commitment to delivering safe, reliable, affordable and clean energy. The CAP process ensures that notifications are categorized, assessed for risk, and assigned to the appropriate owner to resolve issues and implement effective corrective actions to help prevent recurrence. Our goal is to move Gas Operations from a reactive approach of solving issues, to a proactive analysis that helps prevent issues before they result in an incident. The CAP provides real-time data and ensures transparency and accountability. The system is designed to provide trending capabilities and a continuous improvement loop to capture lessons learned and to improve the safety and reliability of PG&E's operations.

Gas Operations officially launched the Gas CAP in October 2013. Its purpose is to offer employees a speak-up method to identify and report issues, or ideas, related to gas assets, and processes. Submissions include employee concerns, suggestions, operational events, internal or external audit findings, data requests, or issues with facilities, tools, records, training, and safety. Since inception, Gas has entered 69,797 CAP notifications and closed 61,974 notifications. Based on the success of Gas Operations' implementation of CAP, PG&E deployed the program enterprise-wide. Deployment was in phases and by the end 2017, all PG&E lines of businesses implemented CAP. Currently, there are seven functional CAP teams that manage eleven lines of business. While each LOB is at its own maturity level, and use the CAP system in different ways, all follow the basic tenets defined in the Enterprise CAP standard[3] and procedure.[4]

The Gas CAP team is composed of CAP operation specialists and cause evaluators. The operation specialists manage the day-to-day entry of CAP submissions, including assignments, coaching and training, reviewing closed CAPs, trending analysis, key word searches and metrics. The cause evaluators facilitate the end-to-end process of an investigation, or cause evaluation (root, apparent or common cause), including team training, interviews, analysis, report writing and working with the functional leader for approvals. The cause evaluation team is also responsible for all SIF investigations and works in conjunction with Corporate Safety to ensure effective implementation of the process.

What Gets Reported into CAP

PG&E encourages employees to identify issues related to gas assets, processes and overall safety of our employees, contractors and public to be entered into CAP for resolution and tracking. There are a few issues that may fall outside the scope of CAP (e.g., IT, Compliance and Ethics, facility requests); however, we do not discourage their entry, but will transfer the CAP notification to the most appropriate tool/program for follow up.

How the Gas CAP Process Works

Initiation: The initiator, who can be any PG&E employee (or contractor with network access), can submit any issue or process improvement idea into the CAP. They have several ways to submit an issue such as through the CAP website, the mobile CAP App, calling the CAP helpline, submitting a paper form, via SAP, or by e-mailing the CAP help desk. Once the CAP is in submitted status in Gas Operations, the Gas CAP team will process it for assignment. On average, Gas employees submit 31 CAP notifications each day.

Assignment and Resolution: The CAP process employs a standardized approach (Figure 6) to reviewing and assigning CAP notifications. This process is facilitated by the Gas CAP Review Team (CRT). The Gas CRT is composed of Subject Matter Experts (SME) from various Gas departments that meet regularly to review newly submitted CAP notifications. The CRT's function is to categorize each notification, assess it for risk (using the enterprise CAP risk matrix), and assign it to an issue owner. After the CRT meeting the CAP team finalizes each issue and prepares them for release to the agreed upon issue owner. On average, the CRT reviews 47 CAP notifications per meeting.

Once the CAP is assigned to an issue owner, it is the issue owners' 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 risk and evaluation level).

After a CAP notification has been submitted and released to an issue owner, initiators receive an e-mail detailing to whom their notification was assigned. They also receive an e-mail again when their notification is closed. This gives the initiator the opportunity to learn how the issue was resolved, and to provide feedback on their satisfaction with the results.

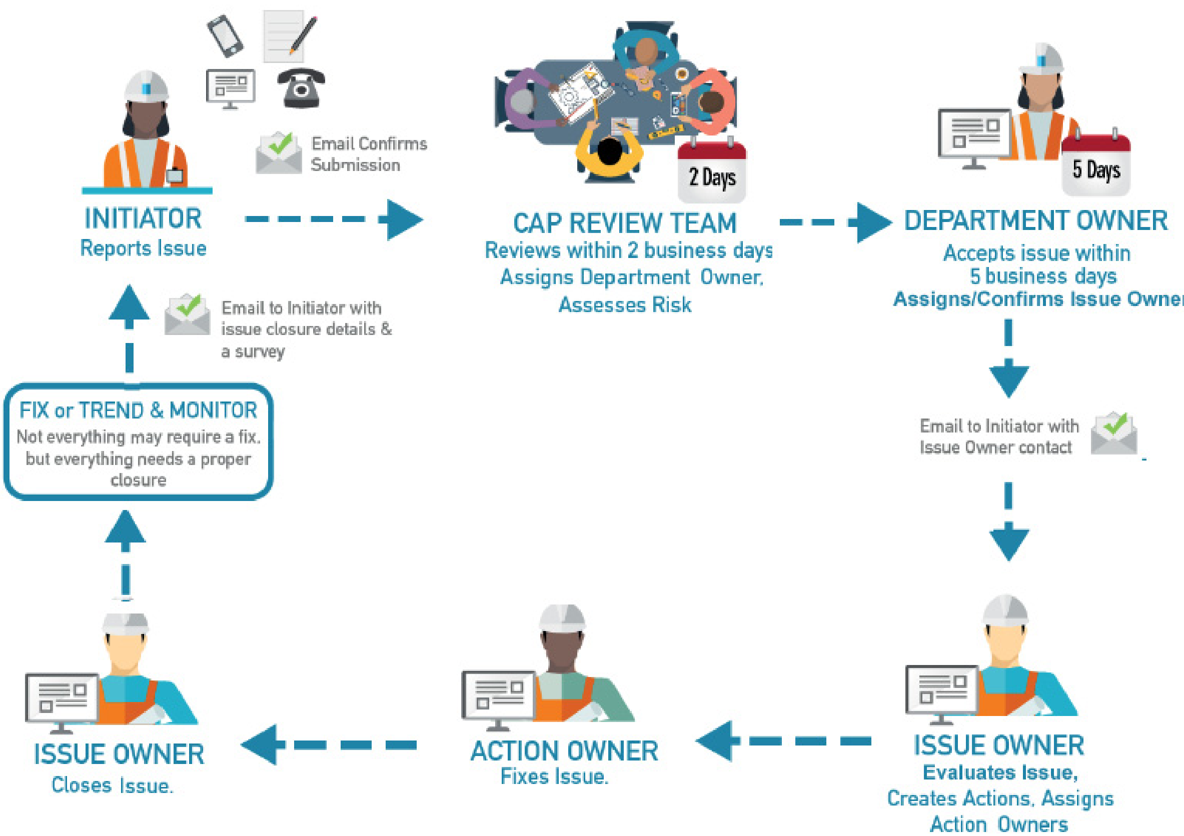


Figure 6 – CAP Process

How Notifications are Risk Ranked

Risk matrices are used to rate and compare risk of hazardous events by considering the likelihood and consequence of an event happening, to increase visibility and help with decision making on risk reduction processes. Risk and safety are highly dependent on an individual's perception, meaning risk and safety mean different things to different people. Risk matrices are designed to minimize individual influence and normalize risks to be uniform, regardless of who is risk ranking hazards. Risk matrices, especially when assessed qualitatively, provide only an estimated assessment of risk and are used to provide initial decision guidance and do not produce definitive risk assessments. Quantitative risk assessment methods are available when a better estimate of risk is required in order to better allocate resources. The CAP risk matrix is a qualitative risk assessment.

The initial risk ranking of a CAP notification is based on the information available and application of the following calculation to assist reviewers with combining known facts to identify the risk of the CAP notification:

Probability of Event Occurrence x Severity of Consequence = CAP Notification Risk

- **Probability of Event Occurrence**: The extent to which an incident, event, or condition has occurred or recurred (frequency).
- **Severity of Consequence**: The result of an incident, event, or condition by considering the degree[5] the public, employee(s), or property was in jeopardy of harm or loss (severity). This includes an assessment of the risk associated to safety, asset damage, reliability, financial impact, compliance, environmental, and reputation.

The CAP notification risk level is used to determine the appropriate evaluation type that will be assigned and provides Gas operations with the ability to prioritize CAP notifications. Cause evaluations are necessary to identify the cause of an incident, issue or error, to prevent or minimize the probability of reoccurrence and to apply continuous improvement processes. There are four types of cause evaluations:

- **Root Cause Evaluation (RCE):** An RCE is a formal and rigorous investigation that uses industry-accepted 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.
- **Work Group Evaluation (WGE):** A WGE is a logical evaluation of an issue to identify reasonable corrective or preventive actions needed to resolve an issue. Resolution of the issue may be addressed by another process, or a simple explanation of why something does or does not happen.
- **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. CCE can only be conducted 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.

A cause evaluation can be related to a wide range of topics in Gas Operations, such as asset failures, reliability (e.g., dig-ins, overpressure 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. Figure 7 shows the total number of evaluations completed in 2019.

RCE	ACE	WGE	CCE
0	56	13,031	0

Figure 7 – Cause Evaluations Completed in 2019

How CAP Success is Measured

In 2019, Gas Operations' goal was to engage at least 33 percent of its workforce to use CAP, and it exceeded that goal by engaging 39 percent. In 2019, Gas Operations employees submitted 12,984 notifications —averaging just over 1,000 per month—and closed 13,087 notifications.

To ensure transparency, leaders receive an Executive CAP Dashboard Report (Figure 8) each week that details how their organization is performing on their CAP items. Key performance indicators reported in 2019 include:

- Percent of Unique Initiators – This is the number of employee submissions divided by the total count of employees. The 2019 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 2019 goal was 1.0, meaning that the volume of closed notifications equals the volume of submitted notifications.
- Average closure satisfaction (1-5 scale) is the sum of survey scores divided by the number of survey submissions. The 2019 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) is the number of CAP notifications passing quality review divided by the number of CAP notifications reviewed. The 2019 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 2019 goal for average age of open high-risk notifications was 230 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 2019 goal for average age of open medium-risk notifications was less than or equal to 230 days.

Figure 8 shows how Gas Operations performed against the above-mentioned key performance indicators in 2019.

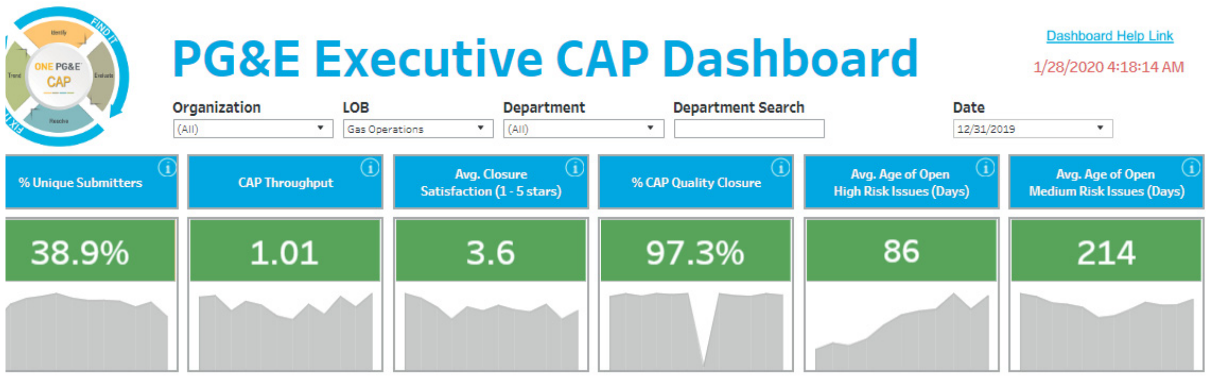


Figure 8 – CAP Metrics

Continuous Improvement and Speak Up Culture

The Gas CAP process continues to mature and serves an important role in Gas Operations to identify and mitigate operational and safety issues and implement process improvements. The Gas CAP department also looks for ways to improve how it supports the business and continues to bring added value to operations. Examples of improvements made by the CAP team in 2019 includes revamping the Eagle Eye Program, implementing an enhanced trending program, and improving its quality closure review process.

Eagle Eye Program: The Eagle Eye Program was created to recognize employees who use the CAP to identify and address issues that result in significant improvements to safety, reliability, compliance, cost reduction, or process. The program was so successful in Gas Operations that all of PG&E's lines of business adopted the Gas model when CAP was deployed company-wide. In 2019, the CAP Department revamped and relaunched its Eagle Eye Program to include awards for both the find it (submitting an issue) and the fix it (resolving an issue). Fifteen Gas employees were awarded an Eagle Eye award in 2019.

Trending: In 2019, the CAP team improved its methodologies and capabilities within the trending program to track and analyze similar or repeat issues. As part of our efforts, the process evolved from capturing cognitive trends during CRT meetings by standing up a new structured potential trend process. The potential trend process complements the cognitive trend process by creating a formalized systematic statistical approach. Using these processes, the team is able to capture emerging trends that can be further analyzed and communicated to key stakeholders within Gas Operations.

The new potential trend process was piloted in December 2018, and fully implemented in 2019. Through this approach, the CAP team discovered 19 potential trends in 2019 and provided analysis and recommendations to the respective functional team in Gas Operations.

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. To meet QCR the notification must meet the following: 1. Well defined issue; 2. Not closed to promise; 3. Sufficient documentation; 4. Justification for no action taken; and 5. Extent of Condition performed (if required). Prior to 2019, Gas CAP reviewed a subset of all the closed CAP notifications on a monthly basis. Beginning mid-2018, Gas CAP reviews 100 percent of all closed notifications on a weekly basis. If the CAP team determines that a notification did not meet the minimum requirements of QCR, then a team member will reach out to the issue owner and coach them on what a quality closure should look like. This process adds value to the organization by creating an expectation on how a notification should be resolved and closed.

b) COMPLIANCE AND ETHICS HELPLINE

PG&E's Compliance and Ethics (C&E) Helpline is a toll-free telephone number available to employees, contractors, consultants, suppliers, and customers 24 hours a day, 7 days a week. The C&E Helpline, managed for PG&E by NAVEX Global, enables callers to request guidance about our Code of Conduct (COC) or make a good-faith report of violations of our COC such as fraud, accounting issues, or illegal activity. Callers may remain anonymous. In addition to calling, other methods to contact C&E to request guidance or submit a report include making a web-based report (also managed for PG&E by NAVEX Global) or contacting C&E directly.

Concerns raised with C&E through its Helpline or any other method are documented and tracked to closure. PG&E has a strict policy against retaliation against anyone who speaks up or is involved in an investigation. The C&E Helpline is part of PG&E's commitment to fostering a workplace where everyone feels safe to ask for guidance, share ideas or raise concerns—and one where everyone is confident that those concerns will be heard and taken seriously.

In addition to the C&E Helpline, PG&E's Federal Court-Appointed Monitor[6] has a dedicated hotline, e-mail, and website that employees and the public can submit concerns. Although the hotline is not equipped to handle safety emergencies or other issues requiring immediate attention, it is another resource for employees to raise issues or concerns.

c) MATERIAL PROBLEM REPORTING

PG&E also encourages employees to report and act on problems with any materials, tools, gas/ electric/other equipment or infrastructure through the Material Problem Reporting (MPR) system. PG&E

leverages the CAP reporting process 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 ensure proper corrective actions are implemented. In 2019, this process had an average cycle time of 19 days, with a target of 20 days. The target for this process in 2020 is 20 days.

Field MPRs tend to be more complex, and as a result, may require more time to resolve. They require collecting the part from the field, shipping it to engineering, performing an investigation and interviews on method of installation, and material testing in a test lab to validate the method of failure. After the conditions and method of failure are determined, the material may be sent back to the manufacturer if it is proven to be defective. In 2019, Field MPR resolution had a 154-day average cycle as compared to its target of 70 days. The target for this process in 2020 is 70 days. To improve the resolution times in 2020, MPR closures will be risk rank driven, evaluators will be required to take mandatory MPR training, and an MPR closure target will be added to the evaluators' safety metrics.

2. PG&E Corporate and Gas Safety Committees

PG&E's safety governance structure drives a consistent safety culture and aligns to PG&E's safety strategy and results. Table 1 describes PG&E's Corporate and Gas Operations safety committees.

Table 1 – Safety Committees	
Board of Directors Safety and Nuclear Oversight Committee	Oversees matters relating to safety, operational performance and compliance. Conducts an annual evaluation of PG&E's performance in accordance with its Corporate Governance Guidelines.
Enterprise Safety Committee	Provides overall governance of safety; guides the enterprise safety strategy and philosophy; and drives continuous improvement of public, employee, and contractor safety performance.
Gas Operations Safety Council	Sponsors initiatives to improve LOB safety. Monitors LOB's safety performance and initiatives so that safety initiatives adequately address risks.
Gas Operations Grassroots Safety Teams	Employee-led efforts to identify opportunities to improve safety, define and validate possible solutions, and implement and promote safety initiatives.

a) Gas Operations Safety Council

The Gas Operations Safety Council meets on a monthly basis and is facilitated by the Senior Director of Safety, Quality and Contracts Management. The Council is composed of all Gas Operations Senior

Leadership. Invited attendees include the Labor Unions, Grassroots Safety Teams, the Federal Monitor, Gas Safety, Corporate Safety and other key stakeholders as needed. The primary objective is to provide overall governance of safety, guide department safety strategy, ensure compliance with Company safety standards, execute Chairman's Risk and Safety Committee directives, and promote positive safety culture change. The monthly Gas Safety Council has a standing agenda item for the Enterprise Safety Committee, allowing for information to align and flow between the enterprise and Gas Operations.

b) Gas Operations Grassroots Safety Teams

Gas Operations Grassroots Safety Teams are composed of Chairs, Co-Chairs and members from Transmission & Distribution (T&D) Operations, Gas T&D Construction, Asset Management & System Operations, and Safety Quality & Contract Management. Chairs meet on a regular cadence to discuss issues, strategy, concerns, successes, roadblocks and any barriers that may exist. As of December 2019, Grassroots had over 140 members.

On a quarterly basis, a Grassroots leadership meetings are held to inform and obtain leadership endorsement of the sustainable approach to Gas Operations Grassroots Safety.

III. Process Safety

Process Safety Management[7] focuses on preventing low frequency, high consequence incidents, and mitigating the consequences from these incidents. The Process Safety Management System is used for engineering new facilities, modifying existing facilities, maintaining equipment, and ensuring safe operation.

The Process Safety Management System contains four foundational areas (Figure 9): Commit to Process Safety, Understand Hazards and Risk, Manage Risk, and Learn from Experience. PG&E is improving process safety performance by strengthening performance in each of these areas. Process Safety Management System is well intermeshed within the GSEMS, [see Section I.2 *Gas Safety Excellence Management System*] to safely manage the planning, construction, operation, decommissioning and maintenance of gas assets and associated activities and ensure the safe, reliable, affordable and clean delivery of natural gas.

Figure 9 – The PG&E Process Safety Management System

When process safety performance gaps are identified, plans are developed and implemented to close them. A follow-up assessment is conducted to ensure progress remains on track and to verify performance improvement.

Process Safety Highlights from 2019 include:

Commit to Process Safety. Guided by the elements set by the Center for Chemical Process Safety (CCPS), PG&E's commitment to implement process safety aligns with API Recommended Practice (RP) 754 *Process Safety Performance Indicators for the Refining and Petrochemical Industries*.[8] Process Safety and Gas Safety Excellence teams use a risk-sorting criterion to track and trend process safety leading and lagging indicators. This helps identify emerging issues before incidents occur.

The Process Safety team performed field location visits to engage the workforce in improving the Process Safety Management System. More specifically, the Process Safety team conducted process safety gap assessments for gas manned facilities to assess individual and group values towards safety and enable the manned facilities to understand where they are in terms of risk acceptance. The benefits of performing the process safety assessments include:

- Identifying positive and negative aspects of the onsite process safety, health and environmental safety program;
- Assist in identifying opportunities for improving process safety, health and environmental safety; and

- Identifying perception gaps between managers, supervisors, and the workforce.

In addition, the Process Safety team continued to review changes to existing procedures and standards and new procedures and standards in order to help Gas Operations operate and maintain safe facilities and consistently implement process safety practices.

Understand Hazards and Risk. Process Safety Management is a key component in reducing PG&E's Operational Risk Exposure. In 2019, PG&E used process safety principles in its large overpressure (OP) event reduction initiative [see Section IV.5.l. *Mitigating the Risk of Loss of Containment: Overpressure Elimination Initiative*]. The Process Safety team continued to lead the investigations of large OP events. The team also continued to focus on maturing design risk assessments, simplifying project design-phase Process Hazard Analysis (PHA) activities and checklists, and conducting facility PHAs.

Manage Risk. Process Safety efforts support risk mitigation. In 2019, risk mitigation continued through Management of Change (MOC) (Figure 10) process improvements. The Process Safety team conducted a MOC effectiveness review and gap analysis within Gas Operations and has been working with stakeholders to close the identified gaps. The focus of the MOC program is to ensure all changes to a process are properly reviewed, and hazards introduced by the change are identified, analyzed, and controlled prior to implementing the change. MOC provides a systematic approach towards mitigating risks associated with changes to facilities, operations, assets, guidance documents, organizations, tools and/or equipment. This approach helps to ensure the continued safety of the workforce throughout the process. As such, Gas Operations developed and published the following MOC procedures, amongst others:

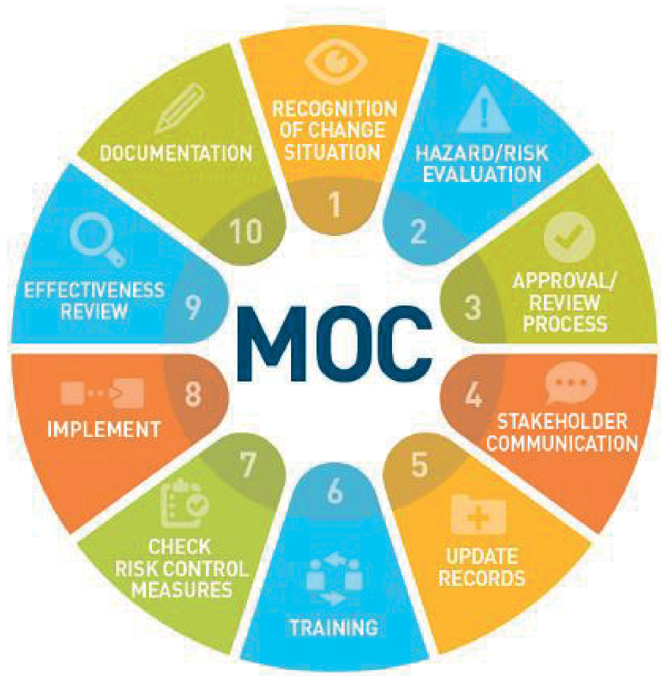


Figure 10 – Gas Operations MOC Process

- Change Control Process for Gas Organizational Changes[9]
- Field Design Change Process for Distribution Lines and Dual-Asset Facilities [10]
- Field Design Change Process for Transmission Pipelines and Transmission Station Designs[11]

In addition, the team initiated a MOC Community of Practice. This endeavor serves as a platform to engage and communicate best MOC practices among various Gas Operations teams.

The Process Safety team also developed and conducted API RP 754 training, updated the Pre-Startup Safety Reviews (PSSR) checklist, and updated PHA and PSSR trainings. The Process Safety team revised and focused the Process Safety Management training to reach a larger population within Gas Operations.

Learn from Experience. PG&E strives to continuously improve in process safety. Process Safety engineers support investigations and lead cause evaluations, as part of the CAP process. Cause evaluations are conducted to identify the cause of an incident, the issue, or why an error occurred, to implement recommendations or safeguards that will reduce the risk (severity and/or probability) of recurrence and to apply continuous improvement. These evaluations include the identification and implementation of corrective actions so that PG&E can reduce the risk that similar incidents will occur in the future. Corrective actions resulting from PG&E's investigations are implemented every day to strengthen safeguards. In addition, lessons learned from incidents are shared through Process Safety Moments. Process Safety Moments are a standing agenda item within Gas Operations' monthly Risk and Compliance Committee (RCC) meetings. Cross functional teams are assigned to present Process Safety Moments during these RCC meetings.

In 2019, Gas Operations reached a key milestone in the journey of Process Safety Management maturity. Gas Operations was recognized, through a third-party assessment, for being in compliance with the intent of API RP 754, Process Safety Performance Indicators, in so far as it meets its business operations, demonstrating a commitment to incident prevention. The Process Safety Indicator (PSI) dashboard, based on a pyramid framework where the most leading indicators are at the bottom of the pyramid (Figure 11), has been reviewed monthly with Mega Process Owners and presented bi-monthly at Keys to Success (KTS) meetings and other senior leadership platforms. The discussions and decision making starts at the base of the pyramid (Tier D), where process safety metrics are most leading and indicate challenges to operating discipline and management system performance such as training, inspection programs and emergency response preparedness. Travelling up the pyramid (Tier C), metrics indicate challenges to safety systems, including quality of corrective actions, gas emergency response and project delivery system adherence. Aligning metric owners by Mega Process strives to drive ownership and accountability and ensure indicators are acted upon to prevent a major gas incident (Tier A and B) that can lead to serious injuries,

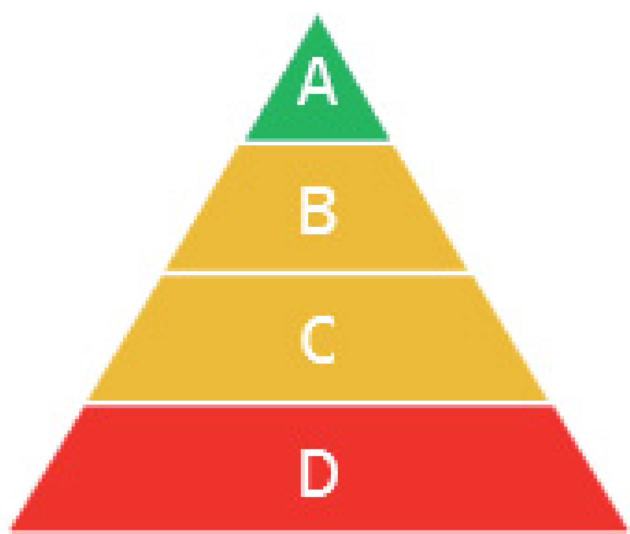


Figure 11 – Pyramid Framework for PSI Dashboard

fatalities, or cause significant interruption to the gas business. Metrics are evaluated continuously and at the beginning of the year to ensure that Gas Operations has the right metrics to drive the right continuous improvement conversations.

IV. Asset Management

PG&E builds, operates, and maintains natural gas infrastructure to transport, store, and deliver gas to customers over Northern and Central California. PG&E faces inherent risks associated with operating an asset system that passes through populated areas and a wide variety of terrain. The three primary risks confronting PG&E's natural gas system are a loss of gas containment, a loss of gas supply, and an inadequate response to emergencies. The third component of PG&E's GSEMS is an asset management system to address these categories of risk and find the balance between asset risk, cost, and performance. The basis of achieving safety through asset management is to know PG&E assets and their condition, understand the risks to those assets, implement risk reduction strategies, and optimize asset risk, cost, and performance. The following section describes PG&E's asset management system, the asset families, how PG&E's Gas Operations 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, affordable management and operation of PG&E's gas assets. Using the international Publicly Available Specification (PAS) 55-1, International Organization for Standardization (ISO) 55001, and API RP 1173 standards as guidance, PG&E's asset management system focuses on:

- Identifying and reducing operational and enterprise risk;
- Maintaining an asset management framework and directing organizational focus on the most important asset risks and opportunities;
- Proactively managing the condition of gas assets; and
- Meeting or exceeding the requirements of federal, state, and local codes, regulations and requirements in an environmentally sustainable manner.

The Gas Safety Excellence Policy lays 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 also maintains risk-based Asset Management Plans for each of its nine gas asset families. Finally, PG&E reports regularly to the CPUC on its safety and reliability investments.[12]

2. ASSET FAMILY STRUCTURE

Since assets can face different types of risk, PG&E developed an asset family structure to recognize and manage these differences, yet drive consistency in the way PG&E thinks about and addresses risks. PG&E identified nine asset families within Gas Operations which are illustrated in Figure 12.

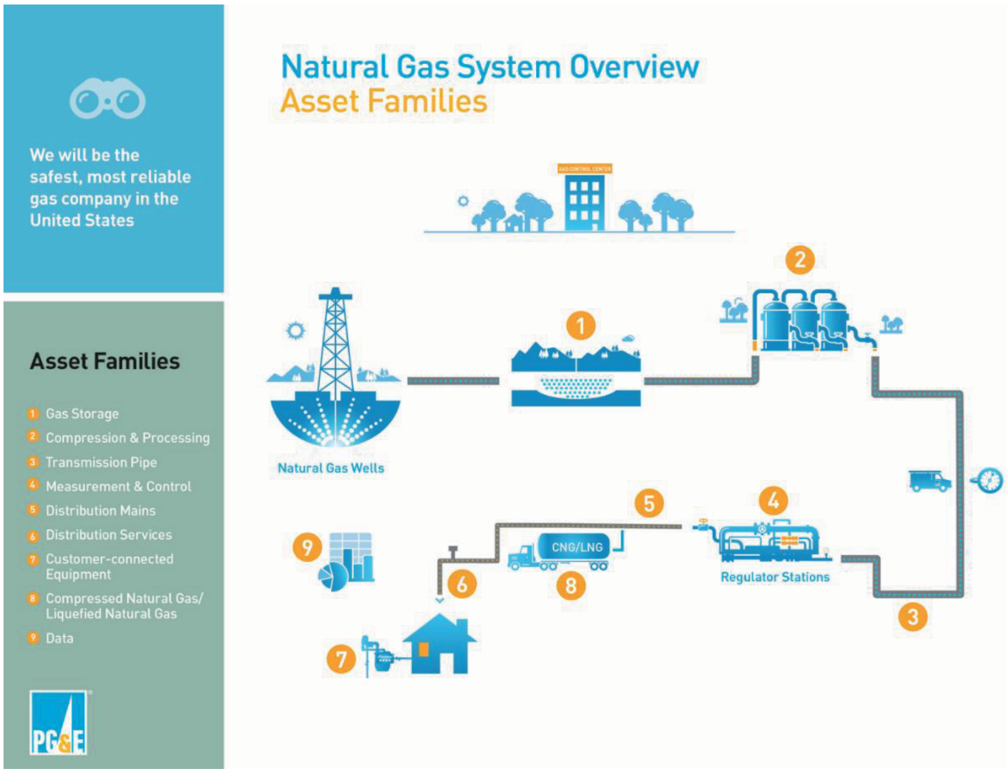


Figure 12 – Natural Gas System Overview – Asset Families

Each asset family has an Asset Family Owner who is responsible for knowing the asset condition and the risks to the assets, and developing a risk-based Asset Management Plan, which is a five-year plan for managing gas assets. For 2019 changes to PG&E's Asset Management Plans, please see Attachment 2**.**

By associating each asset with a family, and designating an Asset Family Owner, Gas Operations works to (1) adequately identify each threat; (2) appropriately assess the condition of the asset and the quality of the data about the asset; (3) identify and assess the threats and risks facing the asset; and (4) develop and execute effective mitigation efforts. The Asset Family Owner leads the preparation of the Asset Management Plan 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
- Areas for continual improvement

These Asset Management Plans are living documents evolving as new asset information becomes available. The following section summarizes the types of assets in each family, the function these assets serve in the gas system, and progress towards achieving Asset Management Plan objectives.

a) Gas Storage

Presently, the Gas Storage Asset Family includes PG&E's owned and operated underground natural gas storage facilities at McDonald Island, Los Medanos, and Pleasant Creek. The primary assets within this family include 111 storage wells, 14 miles of transmission pipe, well controls for each injection and withdrawal wells, and 3,404 acres of storage reservoirs with over 102 billion cubic feet (Bcf) of working gas capacity.

Figure 13 – Rig and Well Platform

However, the landscape for 2020 and beyond will be different as demand forecasts project a decline as California works to meet its Greenhouse Gas emissions goals and new regulations that have initiated major changes to the requirements around design, risk and integrity management, and Operations and Maintenance (O&M) for wells and reservoirs that impact our current asset structure and reliability model.

The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) issued its Interim Final Rule in January 2017, adopting all of API RPs 1170[13] and 1171[14] and outlining requirements around risk and integrity management, design standards, emergency response, and training. Additionally, the California Geologic Energy Management Division (CalGEM, formerly known as DOGGR) introduced final regulations effective on October of 2018 requiring modifications to the well design and construction to eliminate the single point of failure and changed the configuration of the wells to tubing and packers resulting in a reduction of the withdrawal capacity by about 40 percent.

Furthermore, D.19-09-025 in PG&E's 2019 Gas Transmission and Storage (GT&S) Rate Case adopted the Natural Gas Storage Strategy (NGSS) that proposed modified storage services with an effective date of April 1, 2020. The NGSS includes the selling or decommissioning of Pleasant Creek (2 Bcf working gas) and Los Medanos (11 Bcf working gas). The process to sell Pleasant Creek commenced following the January 2020 filing of an advice letter detailing the marketing plan with the CPUC. The sale of the Los Medanos facility will proceed following PG&E's filing with the CPUC in 2022 demonstrating that McDonald Island and Gill Ranch (PG&E retains 25 percent ownership of this facility) have adequate capacity to meet demand.

In response to these regulatory changes, PG&E's Gas Storage Asset Family completed an evaluation of both PHMSA's interim and CalGEM's final regulations, amended its Well Risk and Integrity

Management Plan, and filed a seven-year plan to meet the deadlines established by the regulations to periodically inspect wells and retrofit storage wells to tubing and packer by 2025. During the preparation of this report, PHMSA issued its Final Rule that PG&E is in the process of reviewing.

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 2.

Table 2 – Gas Storage Asset Management Plan Strategic Objectives and Progress To-Date

Overall Objective/Goal	Progress Towards Goal
Complete baseline well production casing assessments on 111* wells by 2025 *6 Wells Plugged & Abandoned from 2017-2019, for a net remaining wells of 111	Number of baseline assessments performed: 2013 – 2016: 27 wells 2017: 8 wells 2018: 13 wells 2019: 15 wells and additional 33 wells not previously assessed for casing integrity inspected using through tubing technology (new).
Evaluate and incorporate Well Risk & Integrity Management Plan (WELL) enhancements	2016: Submitted final WELL documentation to CalGEM for approval and identified improvements to WELL to incorporate in scheduled revisions of the publication. 2017: Published updates of WELL to include enhanced design. 2018: Amended WELL and submitted to CalGEM in April 2018. Completed evaluation of final CalGEM regulations when issued. 2019: Revised WELL and filed with CalGEM on 3/31/19 per final regulations for review and approval.
Assess work on transmission pipeline through Transmission Integrity Management Program (TIMP)	2016: Completed written monitoring and assessment plans; Began development of 10-Year Storage Pipe Plan to assess pipe integrity. 2017: 2019 GT&S Rate Case submission included funding request for strength testing pipeline in the Storage Asset Family. 2018: Replaced 1.65 miles of transmission pipe. 2019: No replacement projects due to construction scheduling conflicts.
Continue PHA and PSSR on all well, surface equipment, and pipeline in storage asset family	Number of PHAs and PSSRs complete: 2014: 2 PHAs and 0 PSSRs 2015: 3 PHAs and 7 PSSRs 2016: 4 PHAs and 11 PSSRs 2017: 2 PHAs and 10 PSSRs 2018: 15 PHAs and 5 PSSRs 2019: 24 PHAs and 12 PSSRs; incorporated API RP 754 classifying events according to their tier system.

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

b) Compression and Processing (C&P)

PG&E's C&P facilities move gas from receipt points to customer delivery locations and provide for injection and withdrawal of gas at PG&E's underground gas storage facilities. Gas processing equipment provides gas that is free from particulates and is sufficiently dehydrated and odorized so that it can be transported to the gas transmission and distribution systems meeting quality requirements. The C&P asset family includes nine transmission compressor stations. Storage compressors are also installed at

PG&E's three underground storage facilities. Major assets include the 38 company-owned compressor units, as well as associated equipment such as filter-separators, pumps, motor control centers, station piping, among others. Additionally, this asset family includes approximately 100 gas odorizer units installed systemwide. Together, these stations support the system's reliability and the odor added to gas helps keep PG&E customers safe when gas arrives at their service point.

Figure 14 – Delevan Compressor Station Turbine Exchange

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

Table 3 – Compression and Processing Asset Management Plan Strategic Objectives and Progress To-Date

Overall Objective/Goal	Progress Towards Goal
Apply Facility Integrity Management principles to all stations by 2025.	• Codifying Facility Integrity Management Program (FIMP) in standard. • Developing obsolescence management strategies for specific equipment types. • Performing vegetation inspections at facilities at highest risk of being impacted by existing wildfire.
Reduce total number of compressor unscheduled shutdowns by 10% over two-year average.	Number of unscheduled shutdowns (including rental units) per year: 2019 Target = 264; 2019 Actual = 224.
Complete ECA1 for all transmission stations and pilot a facility through regulatory-approved ECA2 process by end of 2020.	• ECA1: Continued ECA1 production; improved safety on PG&E system through detection and replacement of specific lap-welded pipe segments; actively working to improve data accessibility. • ECA2: Completed field non-destructive evaluation (NDE) and analysis for pilot stations.
Complete critical documents defined by TD-4551S for all facilities by 2021.	• Continued full-scale production. • Exceeded annual target.
Complete physical security upgrades at critical facilities by 2023.	Stations currently being completed according to plan.

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

c) Transmission Pipe

The Transmission Pipe asset family consists of approximately 6,600 miles of line pipe and major components, such as valves and fittings, used in transporting natural gas.[15] PG&E's TIMP governs how PG&E identifies and evaluates risks, reduces risk through risk mitigation activities, and assesses integrity performance within the Transmission Pipe asset family. 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 the federal TIMP regulations.[16] The Transmission Pipe Asset Management Plan describes the roadmap for mitigating and managing risk for this asset family and achieving the established asset management objectives. The plan's objectives include the following:

Figure 15 – Transmission Pipe L-153 Span Removed From I-880

Table 4 – Transmission Pipe Asset Management Plan Strategic Objectives and Progress To-Date	
Overall Objective/Goal	**Progress Towards Goal**
Apply integrity management principles to transmission pipelines covering 100 percent of population living along transmission pipelines by 2030	• 82 percent of population living within Potential Impact Radius covered by Integrity Management principles. • Developed a new Threat Identification model for the Selective Seam Weld Corrosion Threat. • 35.8 percent of system is now piggable. Completed all first time ILI runs and increased total number of smart tool runs by 50 percent since 2018. • See Section IV.5.g for additional information on ILI. • Removed L-153 span overcrossing of interstate 880 (Figure 15). • Added over 5000 new CP monitoring points on the system.
Meet 100 percent of system capacity obligations and eliminate high risk manual operations in peak day conditions by 2021	• Eliminated 1 high risk manual operation. • 8 of 9 transmission regions meet all expected load conditions.
Update PG&E's gas transmission assets and technology to improve recognition and response to significant transmission incidents by 2021	• See Section IV.7.a for additional information on system visibility progress. • Installed 23 automated valves. • Installed 8 local transmission Supervisory Control and Data Acquisition (SCADA) sites. • Established the basis for Incident Mitigation Management (IMM) plan.
Maintain a first quartile Damage Prevention program to further reduce transmission dig-ins	• See Section IV.5.a for more information on PG&E's Damage Prevention Program and progress. • See Section IV.5.b for more information on Line Marker progress.

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

d) MEASUREMENT AND CONTROL (M&C)

PG&E's M&C assets monitor, measure, and control pressure and flow within the gas transmission and distribution 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 16 – M&C Complex Station-Above Ground

The physical assets within this family include three gas terminals, 383 gas transmission stations (both simple and complex), 402 transmission large volume customer meters, 75 automated valve sites, 2,476 distribution district regulator stations, 2,147 distribution high pressure regulating sets, 26 large customer meter sets, and 88 gas quality analyzers. PG&E's M&C equipment is located above and below ground, as well as within vaults and buildings. Examples of M&C complex and large volume transmission stations are shown in Figure 16 and Figure 17.

Figure 17 – Large Volume Customer

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

Table 5 – M&C Asset Management Plan Strategic Objectives and Progress To Date	
Overall Objective/Goal	**Progress Towards Goal**
Apply Facility Integrity Management principles to all transmission and distribution stations by 2025.	• Codifying FIMP in standard. • Developing obsolescence management strategies for specific equipment types. • Performing vegetation inspections at facilities at highest risk of being impacted by existing wildfire.
Install secondary overpressure protection at 50 percent of H-14 facilities by 2022.	• Large OP events per year: 2015 – 7; 2016 – 10; 2017 – 11; 2018 – 5; 2019 – 11. • Published OP Long-Term Execution Plan. Strategy for mitigation of facilities that are most susceptible to large OP events has been developed and is in execution. • Continued installation of secondary overpressure protection devices. Approximately 20 percent of H-14 facilities currently have devices installed.
Complete ECA1 for all transmission stations and pilot a facility through regulatory-approved ECA2 process by end of 2020.	• ECA1: Continued ECA1 production; improved safety on PG&E system through detection and replacement of specific lap-welded pipe segments; actively working to improve data accessibility. • ECA2: Completed field NDE and analysis for pilot stations.
Complete critical documents defined by TD-4551S for all facilities by 2021.	• Continued full-scale production. • Exceeded annual target.
Complete physical security upgrades at critical facilities by 2023.	• Stations currently being completed according to plan.

The M&C Asset Management Plan describes these objectives in more detail.

e) Distribution Mains and Services

Figure 18 – Employee Working on Distribution Service

This asset family includes approximately 43,000 miles of pipeline that connects to the gas M&C asset family on the upstream side and transports natural gas to customers throughout the service area. It also includes over 3.5 million service lines that deliver gas from the distribution mains to the assets in the Customer Connected Equipment family on the downstream side. The programs associated with the Distribution Mains and Services asset family are focused on the inspection, maintenance , and replacement of Distribution Mains and Services assets. PG&E continues to identify and assess threats to Distribution Mains and Services assets and works to mitigate those threats, including through its Distribution Integrity Management Program (DIMP). Some key strategic objectives include the following:

Table 6 – Key Distribution Mains and Services Metrics

Overall Objective/Goal	Progress Towards Goal
Achieve and maintain 1st quartile for 3rd-party gas dig-ins	PG&E set a 1st quartile 2019 target of 1.23 dig-ins per 1,000 tickets. In 2019, PG&E experienced 1.04 dig-ins per 1,000 tickets and outperformed the 2019 target.
Achieve a removal rate of pre-1985 pipe that limits asset age to 100 years by 2030	2013: 69 miles replaced 2014: 66 miles replaced 2015: 102 miles replaced 2016: 120 miles replaced 2017: 145 miles replaced(exceeded the target of 130 miles) 2018: 165 miles replaced (exceeded target of 163 miles) 2019: 126 miles replaced (exceeded target of 125 miles)
Finalize legacy cross bore inspection scope by 2025 and re-establish the inspection timeline	Inspections planned 2013 through 2019: 224,706 Inspections completed 2013 through 2019: 225,053

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

f) Customer Connected Equipment

The Customer Connected Equipment Asset Family is composed of approximately 4.6 million meters and associated regulators, over-protection devices, 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 19 – PG&E Employee Working on CCE

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, 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. The plan's key objectives are included in Table 7:

Table 7 – Customer Connected Equipment Asset Management Plan Strategic Objectives and Progress To-Date

Overall Objective/Goal	Progress Towards Goal
Reach a steady state backlog of 60,000-70,000 non-hazardous meter set leaks for repair annually	2019 end of year inventory: 106,686 (developing a plan to get back on track with this strategic objective).
Identify and remove problematic regulators by 2022	1,632 replaced in 2019 vs 1,517 planned.

The Customer Connected Equipment Asset Management Plan describes these 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 to offset or supplement pipeline flowing supplies for planned outages, winter peak load shaving, unplanned outages, and in emergency situations. The LNG/CNG asset family consists of over 200 portable LNG and CNG units. In 2019, there were no loss of containment incidents for portable assets [see Table 8].

Figure 20 – A Large-scale LNG Injection Site

The LNG/CNG asset family also includes 32 CNG station assets to supply the natural gas that fuels PG&E and third-party vehicles and provides very high-pressure gas supply to the portable CNG equipment. Over the last few years, PG&E has instituted an industry-leading inspection program to assure the integrity of customer CNG vehicle fuel systems. In 2019, 100 percent of PG&E's natural gas fueling customers authorized to fill at our stations submitted their three-year vehicle certificates of inspection. In 2019, there was one significant loss of containment incident for CNG Station assets.

Table 8 – 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	2019 Activities: Continued maintenance of LNG/CNG equipment and assets. LNG/CNG equipment training development and operating training.
Implementing an industry-leading inspection program to improve safety inspection certifications from less than 20 percent to 100 percent of CNG fuel customer vehicles	2019: 100 percent of natural gas fueling customers authorized to fill at our facilities have submitted their presented three-year cylinder certification.
Reduce risk of portable natural gas transportation traffic incidents by reducing equipment issues through an improved maintenance program	2019: Continued maintenance of LNG/CNG portable over-the-road assets by dedicated fleet mechanics have resulted in continued decrease of transport incidents.

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

h) Data

In 2018, PG&E Gas Operations determined that creating an asset family specifically for data is consistent with industry best practice and will provide the appropriate attention and resources to the essential data sets required for the safe and efficient operation of PG&E's gas business. Data should be properly managed to have an appropriate life cycle, generation and disposal considerations, and quality control check points. Other asset-intensive organizations, such as transit authorities and rail companies, employ data asset management strategies, and PG&E is leveraging a similar approach. The benefits expected from implementing this data management approach include a strategic approach to data management, clear accountability for data management and ownership, enabling efficient business decisions, reducing/eliminating duplicative data clean-up efforts and redundant data analyses, prioritizing most impactful data management initiatives, optimized asset life cycle decision making, enhancements in risk modeling (probabilistic) and quantifying risk reduction, and ability to streamline data collection efforts, thus reducing burden of data collection on field personnel.

To achieve this and to the extent possible, PG&E will leverage the existing asset management framework currently utilized for physical assets. Strategic goals, and progress towards those goals are listed in Table 9, below:

Table 9 – Data Asset Management Plan Strategic Objectives and Progress to Date	
Overall Objective/Goal	**Progress Towards Goal**
Develop an Asset Management Plan for data in Gas Operations	Initial Data Asset Management Plan drafted, revisions and consistency with other Asset Management Plans added in 2019.
Develop an asset register with essential datasets and pertinent metadata including the quality, condition, and location of the data	Developed initial Data Asset Register by working with 50+ groups within Gas Operations. Register contains 1,450+ essential datasets.
Develop a framework to assess risk for Gas Operations data	Asset register collected information on datasets including data owner, storage location, and quality.
Develop Data Governance Standard including clearly defined data owners, stewards, and systems of record	Initial thinking and workshops conducted on basic data governance principles.
Improve completeness and accuracy of digital data to support data-driven risk management and work prioritization by 2022	Created initial Asset Register for essential datasets in Gas Operations with assessment of current data quality.
Create all required data asset-related standards and procedures, including a data standard and data dictionary by 2023	Initial drafting of data governance started.

The Data Asset Management Plan describes these objectives in more detail.[17]

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 team prioritizes risks based on how likely an incident is to occur and how severe it might be. While 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 enterprise and operational risk management process. PG&E's Enterprise and Operational Risk Management plans allow PG&E to manage assets and risks at an enterprise and operational level. PG&E defines "Enterprise Risks" as any risk that could potentially have a catastrophic impact to the company. Enterprise Risks and associated mitigation plans are reported to the Board of Directors annually.

Operational risks are actively managed at the LOB level, with oversight provided by each LOB's RCC, which at a minimum meet quarterly. The Gas Operations RCC meets monthly. Each LOB RCC is charged with oversight of risk management activities within the LOB including, but not limited to, reviewing risk assessments, approving risk response plans, and overseeing their implementation. By assessing and managing risks from both points of view, PG&E can better manage the interdependencies and drive for consistency in risk management across the Company. In addition there is an Enterprise Risk Committee of VPs from LOBs who meet monthly, following an annual work plan derived from Session D areas of focus and commitments. These include risk management program strategy, deep dives, and challenge sessions for specific top risks. This process increases Senior Management and Board engagement in risk-informed decision-making by involving them in decisions as the process unfolds, and gives those individuals charged with managing specific assets line of sight to other risks in the enterprise. Since the appointment of the Federal Monitor in 2017, the monitor has been actively engaged in PG&E's risk analyses and helping to improve operations. For example, the monitor attends and participates in Gas Operations' RCC meetings, and also is actively engaged in our integrity management analyses.

Gas Operations identifies, assesses and ranks its risks in a Risk Register in accordance with the Enterprise Operational Risk Management guidelines. The Gas Operations Risk Register is governed by the Gas Operations RCC. Gas Operations' top risks can be communicated to PG&E's executive leadership team at the VP Risk Committee, or at Session D. Risks, including the key risks for each asset family identified during annual risk refresh, are captured within the Asset Management Plans, mitigation programs, and work projects. As the result of the risk refresh process and the 2019 Session D, Gas Operations identified 11 risks as part of the Enterprise Event Based Risk Register. These risks are summarized in Table 10 below.

Table 10 2019 Gas Operations Enterprise Risks

Risk	Description of Risk and Risk Drivers
Loss of Containment on Gas Transmission Pipeline	Failure of a transmission pipeline resulting in a loss of containment that can lead to significant impact on public, employee, and/or contractor safety, property damages, financial losses, and/or the inability to deliver natural gas to customers. Drivers Include: Equipment Related, External/Internal Corrosion, Incorrect Operations, Manufacturing Defects, Stress Corrosion Cracking (SCC), Third Party/Mechanical Damage, Weather Related and Outside Forces, and Welding/Fabrication Related.
Large Overpressure Event Downstream of Gas M&C Facility	Failure of a Gas Measurement and Control station to perform its pressure control function resulting in a large overpressure event that can lead to significant impact on public, employee and/or 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 Distribution Facilities, Cross Bore	Failure of a gas distribution pipeline due to a cross bore resulting in a loss of containment with or without ignition that can lead to significant impact on public, employee, and/or contractor safety, property damages, financial losses, and/or the inability to deliver natural gas to customers. Drivers include: Incorrect Operations.
Loss of Containment on Distribution Facilities, Non-Cross Bore	Failure of a gas distribution pipeline resulting in a loss of containment with or without ignition that can lead to significant impact on public, employee, and/or contractor safety, property damages, financial losses, and/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 damage.
Maintaining Local Capacity on High Demand	Failure to maintain capacity on the system on high demand days. Drivers include: Delay of pipeline safety projects into or near the winter.
Loss of Containment at Gas Measurement and Control or Compression and Processing Facility	Failure at a Gas Measurement and Control or Compression and Processing station resulting in a loss of containment that can lead to significant impact on public, employee, and/or contractor safety, property damages, financial losses, and/or the inability to deliver natural gas to customers. Drivers Include: Welding/Fabrication Related, External/Internal Corrosion, SCC, Third-Party/Mechanical Damage, Weather Related/Outside Forces, Manufacturing Defects, Equipment Related.

Table 10 2019 Gas Operations Enterprise Risks	
Risk	**Description of Risk and Risk Drivers**
Loss of Containment at Natural Gas Storage Well or Reservoir	Loss of containment with or without an unplanned ignition at a gas storage well or reservoir that can lead to significant impact on public, employee, and/or contractor safety, financial losses, and potential long term inability to meet deliverability needs for customers. Drivers Include: Third-Party/Mechanical Damage, Incorrect Operations, Casing Wall Loss, Equipment Related, Manufacturing Related Defects, Weather Related/Outside Forces, and Welding/Fabrication Related.
Loss of Containment on Gas Customer Connected Equipment	Loss of containment on gas customer connected equipment with or without ignition that can lead to significant impact on public, employee, and/or contractor safety, property damages, financial losses, and/or the inability to deliver natural gas to customers. Drivers Include: Customer Equipment, PG&E Equipment, Excavation Damage, Other Outside Force.
Loss of Containment on LNG/CNG Portable Equipment	Any loss of containment during portable operations that can lead to significant impact on public, employee and/or contractor safety, property damages, financial losses, and/or the inability to deliver natural gas to customers. Drivers include: Equipment Failure, Incorrect Operations, and Corrosion.
Loss of Containment on CNG Station Equipment	Any loss of containment during station operations that can lead to significant impact on public, employee, and/or contractor safety, property damages, financial losses, and/or the inability to deliver natural gas to customers. Drivers include: Third Party Damage, Equipment Failure, Incorrect Operations, and Corrosion.
Inadequate Overall Gas System Supply	Inability to meet the required natural gas system supply due to a combination of internal and/or external system and/or market limitations occurring together. Drivers include: Interstate Pipeline Capacity, Interstate Supply Availability, PG&E Pipeline Capacity, PG&E Storage Availability, California or National Weather Conditions, PG&E Electric Demands, Forecast Errors.

Factors impacting more than one LOB are called Cross-Cutting Factors. These factors also follow the Enterprise and Operational Risk Management process. The Cross-Cutting Factors are owned by a single LOB with other impacted Lines of Business providing their input and subject matter expertise during the risk management process. Gas Operations is impacted by several Cross-Cutting Factors owned by other LOBs as displayed in Table 11 below.

Table 11 – Enterprise Risk Management: Cross Cutting Factors	
Risk	**Risk Description**
Seismic	Seismic events can be a significant driver to failure in all LOB assets. Seismic events contribute to the likelihood of asset failure events and to the associated safety, reliability and financial consequences of those events.
Cyber Attack	Impact of cyber-attack events that affect PG&E's risk drivers and consequences.
Skilled and Qualified Workforce	Impact of human performance, workforce continuity and employee skills and qualifications that affect PG&E's risk drivers and consequences.
IT Asset Failure	Impact of technology hardware and software failure that affects PG&E's risk drivers and consequences.
Records and Information Management (RIM)	Impact of records management controls that affect PG&E's risk drivers and consequences.
Physical Attack	Impact of physical-attack events that affect PG&E's risk drivers and consequences.
Emergency Response and Preparedness	Impact of emergency preparedness and response controls that affect PG&E's risk drivers and consequences.
Climate	Impact of climate change on PG&E's risk drivers and consequences.

Table 11 – Enterprise Risk Management: Cross Cutting Factors	
Risk	**Risk Description**
Contact Management	Impact of contract management controls that affect PG&E's risk drivers and consequences.
Third-Party Risk	Impact of vendor actions involving insurance, credit, security and privacy that affect PG&E's risk drivers and consequences.

PG&E continues to improve its risk management process. PG&E is an active participant in the CPUC's proceedings to advance a "risk-informed" process. In Decision 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 Mitigation Phase (RAMP). S-MAP's focus is on the models each utility is using to evaluate risk with the intent of developing a single model for all utilities. RAMP's focus is on risk mitigation, alternatives analysis, risk spend efficiency, and a quantitative measure of expected risk reduction. PG&E filed its first RAMP report on November 30, 2017. PG&E's next RAMP Report filing is due by June 30, 2020. This upcoming filing will incorporate requirements from the S-MAP Decision (D.18-12-014).

4. Records and Information Management

PG&E's Gas Operations records and information management (RIM) team, as part of the Enterprise Records and Information Management (ERIM) Program, focuses on the deployment of consistent, integrated processes that support records development associated with operational safety, regulatory compliance, and knowledge management. ERIM works with all of PG&E to assess and inventory physical and electronic records and implement tools to manage the lifecycle of records, establish specialized plans for vital records in partnership with the business, and monitor the process controls for protecting and storing records. Examples of RIM accomplishments in 2019 include:

- Provided key records management support for Gas Operations' PAS 55/ISO 55001 Certifications;
- Minor non-conformance for records lifted;
- Updated and recertified Gas Operations records inventory;
- Developed nine records process maps for identified Gas Operations business processes;
- Continued physical records remediation in Gas Operations field offices;
- Completed Site Monitoring, analysis and reporting for Gas Pipeline Operations and Maintenance department; and
- Removed physical vital records from 36 sites throughout the territory associated with the Gas Pipeline Operations and Maintenance department to safeguard them in accordance with our vital records standard.

The RIM Ambassador network, composed of Gas Operations staff, continues to be an effective way of communicating records management information throughout the LOB. In addition to the mandatory records training that all PG&E employees receive, the Gas RIM team provides quarterly training to the ambassadors and supports them as they coach their peers in meeting PG&E's records management requirements. In 2020, these offerings will continue to be available to all of PG&E. Additionally, the full-time ERIM Coordinator network supports all LOBs and all territories throughout PG&E by providing records management resources to the field.

Gas RIM continues to implement and refine the comprehensive roadmap which was initially launched in May 2014. The Gas RIM roadmap defines and tracks progress of projects and initiatives to support compliance and risk reduction. Table 12 details some key RIM roadmap initiatives and drivers.

Table 12 – Gas Operations Records and Information Management Roadmap Highlights	
Key Roadmap Initiatives	**Roadmap Drivers**
ERIM Compliance Assessment and Monitoring SharePoint Records Management File Share Cleanup and Migration Disposition Program Implementation	• Records-related remedies and recommendations adopted by the CPUC in the San Bruno Order Instituting Investigation (OII) Penalties decision issued in April 2015 and outlined in PG&E's Initial Compliance Plan associated with Investigation (I.) 14-11-008, an OII associated with PG&E's gas distribution records management practices. • ARMA International's Information Governance Maturity Model. • Continued certification of PAS 55-1 and ISO 55001, and API RP 1173.

5. Mitigating the Risk of Loss of Containment

PG&E takes a proactive approach to reducing 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 "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 processes working in collaboration to educate excavation contractors and homeowners about safe excavation practices near underground infrastructure. Activities, reviewed annually and described in the next sections, include Public Awareness, Dig-in Reduction Team (DiRT), Locate and Mark, and Pipeline Patrol and Monitoring.

Damage Prevention includes marking the field location of underground facilities as requested through the USA One-Call system—commonly referred to as 811, USA ticket management, investigations associated with dig-ins and damage claims, and Public Awareness. The marking of underground utilities is governed by California Government Code 4216 and the process is driven by industry best practices. Table 13 describes other key Damage Prevention programs.

Table 13 – Damage Prevention Programs	
811 Ambassador	The 811 Ambassador Program provides a response mechanism for PG&E employees to take corrective action when they observe excavation with no delineation or markings. All PG&E employees are 811 Ambassadors. Employees learn how to identify excavation-related delineations and utility operator markings as required by the California One Call Law. If an employee observes excavation without the required marks, they call the Damage Prevention Hotline and in response, a DiRT member is dispatched to the job site 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. S/he requests all excavation be stopped, educates the excavator about the requirements of California's One Call Law and the reason for the non-compliance, provides excavation safety materials, and instructs the excavator to correct the noncompliance activity prior to continuing any excavation. In 2019, the Damage Prevention Hotline received 5,858 calls.
Gold Shovel Standard	PG&E continues to participate in the Gold Shovel Standard. PG&E began this program that is now run by a third-party and available to utilities across the nation. The program sets safety criteria that second-party contractors are required to meet to be eligible to do work on behalf of the Utility. The Gold Shovel Standard became an internationally recognized program, with companies in Canada adopting and implementing its certification requirements. The Gold Shovel Standard program is one way that PG&E is making its own communities safer, but also bringing best safety practices to the industry. PG&E requires contractors excavating on behalf of PG&E to obtain the Gold Shovel certification. PG&E acknowledges all contractors who practice safe excavation and monitor offenders who fail to demonstrate safe practices. Unsafe contractors lose their certification.
Damage Prevention Manual and Training	Providing clear and concise instruction around dig-in prevention measures like troubleshooting "difficult to locate" facilities.

In addition, since 2012, 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 flow of gas from PG&E's distribution network. PG&E measures performance for damages impacting either gas service lines or meters/risers (Services) or damages impacting gas mains. In 2019, PG&E's Shut-In The Gas Performance was on average 41.4 minutes for services and 85.13 minutes for mains.

Table 14 – Shut In The Gas Performance (average number of minutes)

	2012	2013	2014	2015	2016	2017	2018	2019
Services	70.00	61.00	52.20	49.00	45.76	45.16	43.30	41.40
Mains	192.00	147.00	120.77	102.80	104.43	103.78	88.77	85.13

Since 2012, PG&E has improved its overall make safe performance on events involving services by 40 percent, and events involving mains by 56 percent.

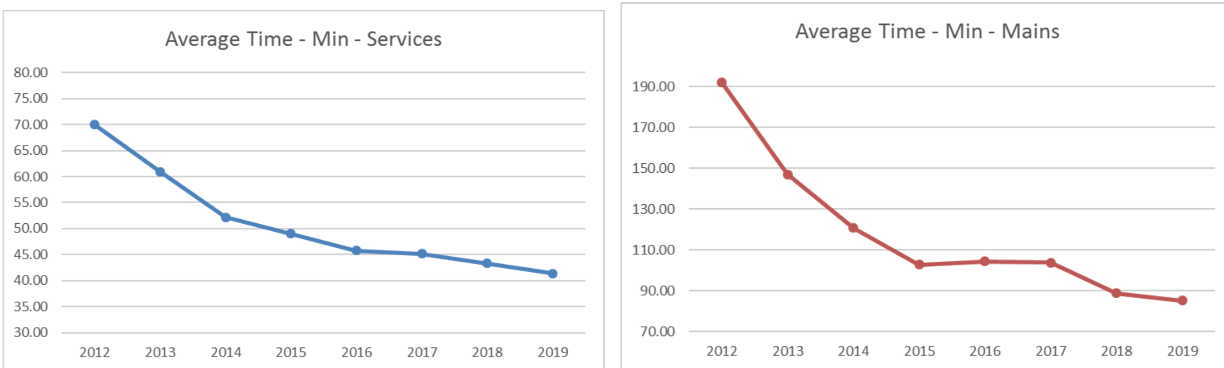


Figure 21 – Shut-In The Gas Performance

PG&E will continue its efforts to improve its Shut-In The Gas Performance.

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, press releases and participation in community meetings and events.

PG&E conducted 148 "811 Call Before You Dig" contractor workshops, reaching over 4,600 attendees, representing over 600 excavation companies or municipalities.

PG&E communicates gas safety information multiple times each year, and in 2019, reached approximately 4 million paper bill customers and sent over 2 million e-mails to those customers who receive paperless billing. In addition to the bill inserts and e-mail campaigns, PG&E also sent a targeted direct mail piece to over 230,000 non-customers[18] 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, homeowner associations, master meter accounts, and those who live or

Figure 22 – Examples of 811 Social Media Campaign

work near PG&E's un-odorized pipelines or storage and compressor facilities. Table 15 identifies highlights from the Public Awareness Program's 2019 activities.

Table 15 – Public Awareness Highlights
Executed a social media campaign targeting homeowners and contractors in areas with high damage rates, promoting the importance of calling 811 before digging. These campaigns reached over 344,000 customers.
Continued to conduct targeted outreach in cities with a high number of dig-ins. The outreach included job site visits, 811 training for top damaging companies and meeting with local leadership to discuss continued partnership for community safety. These targeted efforts resulted in over 8,500 field visits.
Completed 13 bilingual 811 workshops, with 344 participants (farm workers and day-laborers).

ii. Dig-In Reduction Team

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 contractors responsible for excavation damage. The Dig-In Reduction Team is a proactive program that directly and positively affects public and employee safety by striving to reduce the number of excavation damage incidents. PG&E's Dig-In Reduction programs were instrumental in reducing the average number of dig-ins per 1,000 USA tickets from 1.72 in 2018 to 1.04 in 2019.

Table 16 below provides information on some dig-in prevention projects or process improvements.

Table 16 – Dig-In Reduction Team Programs Under Damage Prevention	
PG&E's Commitment to Safety	**Promoting Safety**
DiRT	Deploys investigators to oversee and enhance PG&E's ability to investigate dig-ins, patrol active dig-ins and excavations, and intervene when unsafe activities are identified.
Pipeline Patrol	Identifies and intercepts 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	Conducts safe digging workshops throughout the service territory.

* Beginning January 1, 2016, contractors who wish to excavate or subcontract out excavation work for PG&E must obtain Gold Shovel Standard Certification by making a commitment to safe digging practices in accordance with the California "One Call Law" (California Government Code 4216) and the Common Ground Alliance best practices for excavation.

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 48-hour window. Federal pipeline safety regulations[19] and California state law[20] 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, both natural gas and electric. 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 one-call systems which share a common toll-free, 3-digit "811" telephone number. The California one-call systems are commonly referred to as USA. In 2019, PG&E received over 1.61 million USA tickets.

In December 2018, the CPUC opened an Order Instituting Investigation (OII) involving data that PG&E maintained from 2012 to 2017 regarding the timeliness with which it responded to 811 notifications.[21] PG&E takes the issues raised in the OII seriously and has worked hard to correct them since they were brought to senior management's attention. As such, PG&E implemented a comprehensive corrective action plan (Compliance Plan) with demonstrated results. This Compliance Plan sets out 30 corrective actions across five core areas: Cultural, Process & Procedures, Tools & Technology, Employees & Contractors, and Internal & External Controls. Of the Compliance Plan's 30 corrective actions, all 30 were completed in 2019. PG&E has been, and continues to be on a mission to improve its safety, compliance and ethics culture and to foster a non-retaliatory environment where all employees can confidently and safely speak up, and leaders are consistently listening to and following up on issues raised by employees. Such transformations take time, and PG&E is steadfastly committed to this important work.

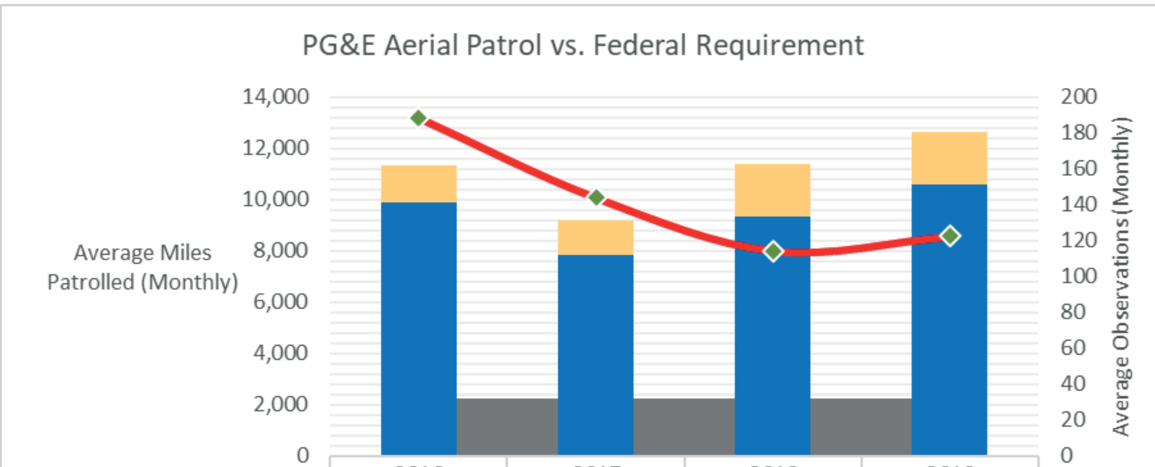
iv. Pipeline Patrol and Monitoring

Pipeline Patrol is a federally required activity that is essential to protecting the integrity of PG&E gas transmission facilities from external threats and in doing so, helps to increase public safety. Patrol is performed by operator-qualified personnel who observe surface conditions near the Right-of-Way (ROW) of transmission pipelines and selected distribution facilities. Patrollers identify and report a variety of observations including Abnormal Operating Conditions (AOC), potential threats to pipeline integrity (e.g., digging, farm-field ripping, boring, blasting, etc.), new construction that may affect Class Location or High Consequence Areas, vegetative cover, and structural encroachments.

Exceeding federal requirements, PG&E's Pipeline Patrol Program seeks to conduct patrols of the entire transmission system monthly.

Figure 23 – Patrol Aircraft With Wing Mounted Camera

PG&E primarily utilizes aerial methods to conduct patrols, with ground personnel dispatched to investigate observations made from the air. Exceeding federal requirements, PG&E's Pipeline Patrol Program seeks to conduct patrols of the entire transmission system monthly, as well as meet an internal goal to patrol pipelines located in High Consequence Areas (populated areas) a second time each month, as conditions permit. 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 the surveillance helps PG&E to identify and stop unsafe excavation practices before dig-ins occur.



	2016	2017	2018	2019
CFR Required	2,243	2,243	2,246	2,230
Special Patrols	1,479	1,352	2,041	2,068
PG&E Patrolled	9,883	7,864	9,367	10,589
Observations	188	144	114	122

Figure 24 – Aerial Patrol Mileage Since 2016

PG&E patrols an average of 9,000 Gas Transmission miles per month using a combination of fixed wing aircraft and helicopters. Since 2016, patrollers have reported over 20,000 observations of potential threats to pipeline integrity and 3,500 reports of new construction affecting class location around the Transmission right of way. Of potential threats reported, approximately 92 percent are construction activities, 8 percent are agriculture, and the remaining include right of way encroachments and geohazards.

b) Pipeline Markers

Pipeline markers and indicators are important damage prevention tools used to indicate the approximate location of the respective pipeline along its route, to prevent “dig-ins” from occurring. Installing markers is required by pipeline safety regulations because markers contribute to public awareness and damage prevention, which in-turn reduces the risk of loss of containment.

Pipeline Markers are signs on the surface above or near the natural gas pipelines located at frequent intervals along the pipeline ROW. The 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 the examples in Figure 25.

Figure 25 – 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, subject to third-party removal or damage, despite being properly installed.

Since 2017, PG&E has installed over 2,800 new markers where road and railroad crossings intersect the pipeline, 2,540 pipeline markers within a person’s unassisted line of sight along the pipeline, and repaired or replaced over 1,700 existing pipeline markers. New decals with current telephone numbers were applied, thereby increasing community safety and gas transmission pipeline visibility above ground.

c) Distribution Pipeline Replacement

An important element of providing safe gas distribution service is replacing aging or at-risk assets. PG&E uses relative risk in prioritizing its pipeline replacement projects. Risk factors include age, material type, leak history, Cathodic Protection (CP), seismic impact, proximity to the public, and other operational factors. In addition to gas main replacement, the program covers related service replacement and meter relocation work.

PG&E has three pipeline replacement programs: Gas Pipeline Replacement Program (GPRP), Plastic Pipe Replacement Program, and Main Replacement Reliability Program. PG&E's objective is to achieve an asset age limited to less than 100 years.

Table 17 – Pipeline Replacement

GPRP	Plastic Pipe Replacement Program	Main Replacement Reliability Program
PG&E began the GPRP Program in 1985, which has focused on the replacement of cast iron and pre-1941 steel pipe, and has enabled PG&E to deactivate all known cast iron main (over 830 miles of pipe). GPRP is now focused on replacing pre-1941 steel pipe. In 2019, the GPRP Program replaced 19.9 miles of pipe.	Since PG&E began its Plastic Pipe Replacement Program in 2012, PG&E has replaced about 500 miles. In 2019, 90 miles of Aldyl-A were replaced. PG&E continues to increase the replacement of Aldyl-A year-over-year in recognition of the approximately 4,900 miles of known inventory.	The Main Replacement Reliability Program focuses on the replacement of pipeline not covered by the GPRP or Aldyl-A programs and will continue to help move the distribution systems average age closer to the national average. In 2019, PG&E replaced 16 miles of distribution pipe through this program.

Figure 26, below, demonstrates the company's main replacement progress from 2010 to 2019.

Main Replacement 2010-2019 Actuals

Program			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
14A	GPRP	Replacement of all cast iron and some steel main installed pre-1940	24.8	28.1	23.4	31.6	26.8	27.5	30.4	36.0	43.6	19.9
14D	Plastic	Replacement of Aldyl-A plastic and similar plastic installed pre-1985	0.0	0.0	17.6	30.7	32.5	63.5	80.4	95.1	91.2	90.0
50A	Reliability	Replacement of gas facilities that have reliability concerns but do not qualify for replacement under the GPRP or Aldyl-A Plastic Replacement Programs	3.7	6.4	7.9	8.2	6.6	13.7	15.8	13.8	28.6	16.0
Total			28.4	34.4	48.9	70.5	65.9	104.7	126.6	144.9	163.4	125.9
Trend				21%	42%	44%	-7%	59%	21%	14%	13%	-23%

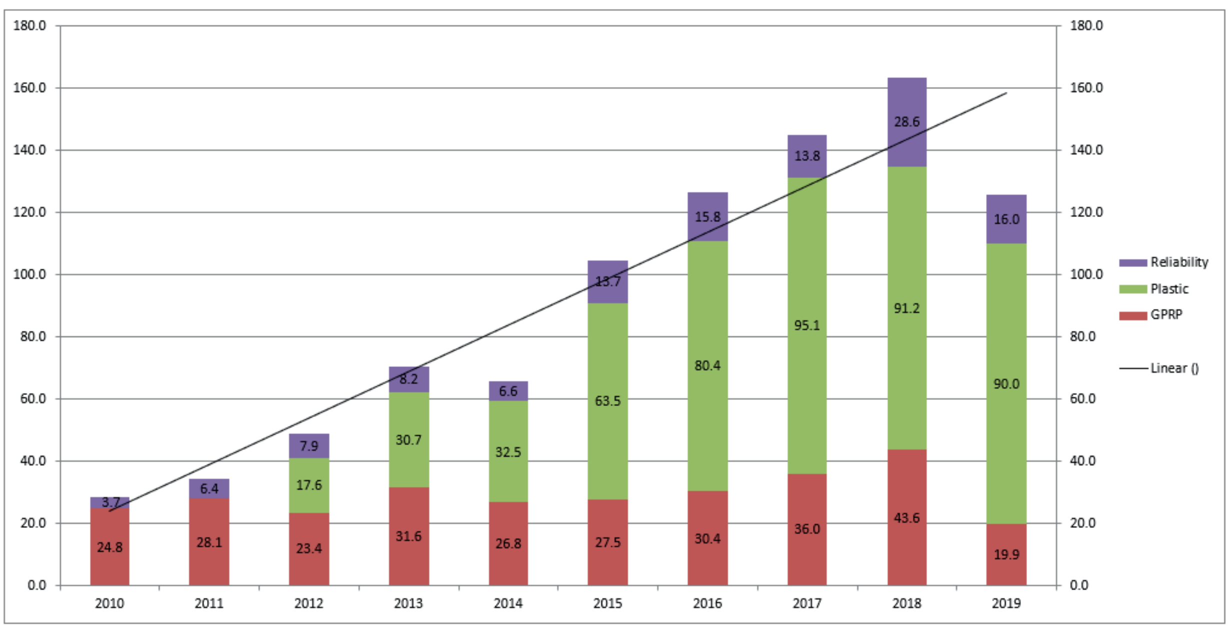


Figure 26 – Main Replacement Progress 2010-2019 (in miles)

d) Cross-Bore Mitigation

A cross-bore[22] 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 no damage has occurred to sewer lines when using trenchless construction methods on new construction projects.

Cross Bore Statistics			
Year	Inspections Completed	Cross Bores Found	Inspections Planned
2013	19,298	148	25,000
2014	33,804	188	38,000
2015	23,530	100	24,000
2016	22,981	94	23,570
2017	35,628	55	30,000
2018	46,043	46	42,500
2019	43,623	37	41,636

Figure 27 – Cross Bore Statistics

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.

PG&E completed approximately 43,623 inspections in 2019. In 2019, PG&E found approximately 1 cross-bore per 1,179 inspections.

e) Strength Testing

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. The strength testing takes a pipeline out of service, clears it of gas, cleans it internally, then fills it (typically with water) to pressures consistent with and pursuant to 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 American Society of Mechanical Engineers (ASME) B31.8S-2004, Section 5, Table 3. This process also results in a test record that establishes the operating pressures the pipe can withstand. A secondary benefit of strength testing for PG&E is that the pipeline is typically upgraded to allow for navigation of the cleaning tools (pigs), allowing PG&E to run ILI tools at later dates [see Section IV.5.g *In-Line Inspection*]. Thus, strength testing is one tool PG&E uses to

Figure 28 – Strength Test in Progress

maintain the margin of safety for the transmission pipeline and reduce the likelihood of future loss of containment incidents that could pose a risk to public safety.

PG&E's goal is to strength test or replace untested transmission pipelines by the end of 2026. Once completed, PG&E will have a test record for its entire gas transmission pipeline system. In 2019, PG&E completed approximately 115 miles of strength testing (Table 18). This work brings PG&E to a total of approximately 1,496 miles strength tested since 2011. The pipeline miles strength tested in 2019 were prioritized based on a risk informed mix of integrity management threats and testing untested pipe lacking a traceable, verifiable, and complete (TVC) record to meet the National Transportation Safety Board (NTSB) D.11-06-017 requirements.

Table 18 – Strength Testing Program								
Strength Test (miles)	**2011-2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
PSEP	539	135	N/A	N/A	N/A	N/A	N/A	674
Subsequent Testing	0	0	79	89	253	286	115	822
Total	**539**	**135**	**79**	**89**	**253**	**286**	**115**	**1,496**

In 2020, PG&E will continue to concentrate on assessing shorter pipeline segment tests addressing NTSB commitments (D.11-06-017) and re-assessing pipeline segments with integrity management threats for both manufacturing related defects and time dependent corrosion threats.

f) Vintage Pipe Replacement

A significant portion of PG&E's natural gas transmission pipeline system, approximately 47 percent, was designed, manufactured, constructed, and installed before the advent of California's 1961 pipeline safety laws. While age alone does not pose a threat to pipeline integrity, PG&E has determined, consistent with industry practice, that some vintage pipeline features, pipelines with certain welds, bends, and fittings located in areas subject to land movement, are most appropriately managed through replacement.

In 2019, PG&E refreshed its program information using new risk results from the previous year. This update continued with our strategic risk prioritization approach to replacing pipe where PG&E defines high-risk land movement areas, prioritizes projects based on total risk, and defines pipe with lower risk to be monitored for risk change through our ILI and Geohazard programs in lieu of replacement or retirement. Based off this risk methodology and updated risk results, PG&E has now identified approximately 123 miles (Tier 1 and Tier 2) of transmission pipe,[23] with some of the characteristics that make it more susceptible to certain construction threats. Of those 123 miles identified, PG&E has further identified approximately 118 miles (Tier 1) of high risk pipe targeting replacement or retirement where vintage fabrication and construction threats interact with high likelihood of land movement in populated areas.[24] Additionally, PG&E is monitoring an additional approximately 1,866 miles of pipeline with vintage characteristics through the ILI and Geohazard programs. In 2019, approximately 2.06 miles of vintage pipe was replaced. PG&E plans to mitigate approximately 4.3 miles of vintage pipe in 2020.

Figure 29 – Vintage Pipe Replaced in San Mateo

Table 19 – Vintage Pipe Replacement Program

	Miles Replaced	Additional Miles Addressed	Percentage of High Risk Mileage Addressed[(a)]
Pre-2015	20.2 miles	1.3 miles	20 percent
2015	5.9 miles	12.7 miles	41 percent
2016	6.7 miles	8.8 miles	45 percent
2017	3.5 miles	11.5 miles	61 percent
2018	20.6 miles	0 miles	74 percent
2019	2.06 miles	0.75 miles	75 percent
Program Target:	123 miles		100 percent

(a) High risk mileage addressed includes pipeline retirements and mileage replaced in other pipe replacement programs from 2015-2019 that have the vintage threat.

As PG&E continues to monitor and assess characteristics of vintage pipelines interacting with land movement through improved data quality and collection, its replacement or retirements are prioritized by addressing sections of pipeline closest to highest density population areas with a high likelihood of ground movement. At PG&E's current and planned rate, the program will address the risk of pipe containing vintage fabrication and construction threats that interact with high risk of land movement for high population density areas by 2027.

g) In-Line Inspection

PG&E's ILI Program uses technologically advanced inspection tools, often called "smart pigs," to reliably assess the internal and external condition of transmission pipe so that action can be taken when issues are identified. Prior to running an ILI tool in a pipeline, a pipeline must be modified with portals called "launchers" and "receivers," and pipeline features that would obstruct the passage of the tool to make the pipeline piggable must be replaced. 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 for pipeline anomalies that must be remediated through the Direct Examination and Repair process where 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.

Figure 30 – ROSEN Electro Magnetic Acoustic Transducer (EMAT) Tool Before an Inspection on L-300A

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

The Traditional[25] ILI Program is ramping up to complete more projects in the next ten years than ever before to reach the goal of 66 percent total system mileage piggable by 2029. As of 2019, approximately 36 percent of the system is piggable. In 2019 alone, PG&E upgraded 246 miles which is a 10 percent increase to overall piggable mileage. In addition, PG&E inspected a total of 478.1 miles with 266.4 of those miles assessed with ILI for the first time. Much of PG&E's pipeline was installed decades before ILI was invented. Today, about 35 percent of the PG&E system is not capable of supporting the running of traditional ILI tools because of design elements like low pressure and/or low flows, small diameter pipelines, and short sections of

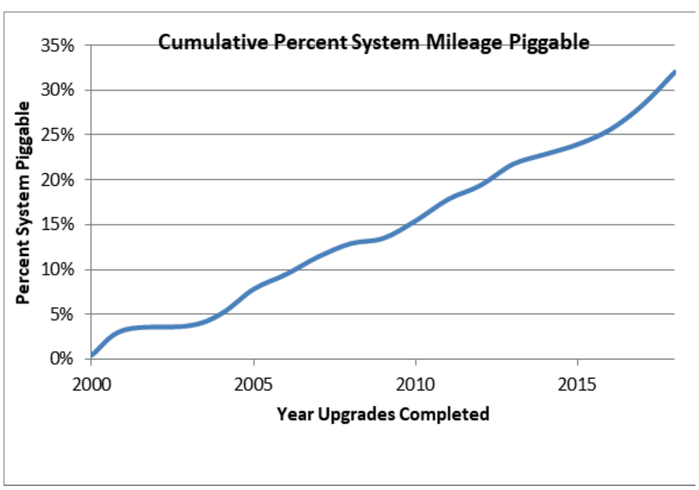


Figure 31 – Progress to-date to upgrade pipelines

pipeline or facility configurations, such as drips or blow downs. Figure 31 details PG&E's progress to-date to upgrade pipelines to make them capable of accepting traditional ILI tools.

h) Corrosion Control

All of PG&E's metallic assets are susceptible to corrosion—a natural, time-dependent process where metal degrades (rusts) due to its interaction with the environment. Gas transmission, storage, and distribution assets primarily composed of steel pipe carrying CNG may experience degradation due to External Corrosion, Internal Corrosion, or SCC. 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 the natural gas being transported. SCC is degradation of the pipe due to cracks induced from the combined influence of tensile stress[26] and a corrosive environment. 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.

Figure 32 – PG&E Employee Installing a Cathodic Protection Rectifier

Given the risk profile associated with corrosion, PG&E has sought out highly qualified corrosion experts from around the country, enhanced procedures, and incorporated systematic, risk-infomed methodologies to its corrosion control approach. PG&E's efforts are resulting in more accurate data on which to make decisions related to the identification and mitigation of corrosion risks, improving the safety and reliability of PG&E's assets.

For example, PG&E mitigates the threat of External Corrosion by installing assets with appropriate coatings and by applying cathodic protection to buried or submerged structures. CP mitigates corrosion through administering direct current through the soil and/or water to steel piping. Coatings mitigate corrosion by forming a barrier between the steel and environment. As coating systems on buried and submerged piping systems cannot readily be inspected for degradation, the use of CP in conjunction with coatings provides additional protection for buried or submerged assets.

PG&E also monitors 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. Overall, corrosion control at PG&E consists of the programs below:

Table 20 – Corrosion Control Programs	
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, 850 Off	Designs, installs, and maintains CP systems to prevent corrosion. In addition, PG&E is implementing a more conservative CP criterion for its transmission piping system.
Close Interval Survey	Collects CP readings at approximate three-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.
Enhanced CP Resurvey	Evaluates distribution piping CP area boundaries, monitoring locations, protection status, and updates documentation to ensure that proper operation of CP systems.
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.
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. PG&E actively participates in corrosion research conducted by the Pipeline Research Council International (PRCI) and supports efforts to incorporate the results of such research into corrosion control regulations and standards through its participation in National Association of Corrosion Engineers (NACE) International, the Interstate Natural Gas Association of America (INGAA), and the American Gas Association (AGA).

i) Earthquake Fault Crossings

PG&E's Fault Crossings Program addresses the specific threat of land movement at active earthquake faults that subject a pipeline to external loads due to seismic events. The program is consistent with California law that requires natural gas operators to prepare for and minimize damage to pipelines from earthquakes. PG&E performs system-wide studies to address both the anticipated geologic movement and pipeline mechanical properties to manage the integrity of the pipe (Table 21). Additional mitigation work is then prioritized, following each study, by considering the likelihood of failure (the probability that the fault will trigger a seismic event), and the consequences of failure (including the impact on the local population, PG&E system reliability, and the environment). Mitigation typically includes modified trench designs, trench adjustment, pipe replacement, or installation of automated isolation valves.

Table 21 – Earthquake Fault Crossing Program		
	Studies[f]	Crossings Mitigated[g]
Pre-2015	52	24
2015	65	18[a]
2016	65	6[b]
2017	22	7[c]
2018	34[h]	25[d]
2019	12	12 [e]

(a) 2015 – 14 crossings were Fit-for-Service (FFS) per current design. 4 crossings replaced.

(b) 2016 – 3 crossings were FFS per current design. 3 crossings replaced.

(c) 2017 – 5 crossings were FFS per current design. 2 crossings replaced

(d) 2018-20 crossings were FFS per current design and 2 were considered mitigated by existing Valve Automation. 3 crossings were replaced.

(e) 2019 – 6 crossings were FFS per current design and 6 crossings were replaced.

(f) Studies are conducted to determine if pipe is FFS with geological, pipe assessments.

(g) Crossing is mitigated if pipe meets or is designed, retrofitted, or replaced to satisfy the FFS criteria.

(h) The difference between this report and PG&E's Transmission Pipeline Compliance Report 2019-01 submitted on January 30, 2019 is timing of data confirmation.

Figure 33 – Pipeline Replacement after the July Ridgecrest Earthquake

j) Leak Survey

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

PG&E outlines current requirements, standards, and guidelines for the Leak Survey and Detection Program in its procedures. In 2019, PG&E surveyed over one million gas distribution pipeline services, over 13,000 gas transmission pipeline miles, and performed daily leak surveys on 115 wells in compliance with CalGEM's emergency gas storage regulations. In addition, PG&E performed quarterly surveys in compliance with California Air Resources Board (CARB) regulations at PG&E's gas storage facilities and compressor stations. PG&E conducts leak surveys on more assets today in accordance with the CPUC's GO 112-F, which changed the survey frequency for some gas transmission pipelines.

In 2015, PG&E implemented the use of an advanced leak detection technology, Picarro Surveyor, into a standard leak management operating model. Since 2017, PG&E's operating model is being used in each division as a standalone process. This has created additional efficiencies and lower overall cost to the Company. Using this model, we have been able to complete our compliance survey in a more timely fashion. The second step in the model's process is to immediately repair all hazardous leaks identified during the survey and to schedule for repair all identified leaks that meet the schedulable leak criteria. Finally, PG&E bundles the scheduled leak repair job packages allowing a more efficient and effective repair strategy. PG&E continued this process in 2019 and met 75 percent of its three-year distribution system compliance survey requirements using its local Picarro approach.

PG&E transitioned from a four-year survey cycle in 2017, to a three-year survey in 2018 as a result of Best Practice 15 in the Leak Abatement OIR D.17-06-015. PG&E will continue its expanded use of the Picarro technology in all of its divisions, completing at least 75 percent[27] of its gas distribution compliance survey. The expanded use of the Picarro technology and the acceleration of 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 GHG emissions.

In addition, in 2019, 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 10 standard cubic feet per hour of methane. As a result, in 2019, PG&E completed the Super Emitter survey on 96.8 percent of its gas distribution services. The purpose of this survey is for Picarro to identify and measure the leak flow rates of Super Emitters as they are found during compliance survey. The data will then inform PG&E of the prevalence of these leaks and the emission reduction that can be gained by repairing them quickly. In 2020, PG&E will continue the Super Emitter survey across the entire system.

To further enhance its Leak Survey process, in 2019, PG&E implemented technology to enable an end-to-end paperless transmission leak survey process and integrated with enterprise systems. Initiatives are in progress to continue to build and support a full end-to-end paperless process for distribution leak survey. In 2019, PG&E implemented an application that allowed Leak Survey to create and document all leaks electronically.

Summaries of PG&E's 2019 Leak Survey cycles for its distribution and transmission pipeline systems are shown in Table 22 below:

Table 22 – Leak Survey Frequency		
Facility Types		**Survey Frequency**
All Company facilities within business districts and public buildings	Distribution Maximum Allowable Operating Pressure ((MAOP) <60 psig)	Annual
Buried metallic facilities not under CP and not covered by an annual requirement		3 years
Balance of underground distribution facilities		3 years
Department of Transportation All Odorized Transmission	Transmission (MAOP > 60 psig)	Semi-Annual
Gathering: Class 1, 2, 3 and 4	Transmission (MAOP > 60 psig)	Semi-Annual
Stations: Class 1, 2, 3, and 4	Transmission (MAOP > 60 psig)	Semi-Annual
Perimeter of Enclosed Electric Substations and Switching Stations		Every 6 months
Wellhead, attached pipelines, and surrounding area	Gas Storage	Daily
Method 21 on all above ground components at 3 Underground Storage Facilities and 9 Compressor Stations	Gas Storage and Compressors	Quarterly

k) Leak Repair

Pipeline safety regulations and guidelines require PG&E to repair certain leaks. In 2019, PG&E's trained and operator-qualified personnel classified leaks into three grades (Grade 1, 2, and 3) based on the severity and location of the leak, the risk the leak presents to persons or property, and the likelihood that the leak will become more serious within a specified amount of time. PG&E's leak grading practices for Grade 3 leaks exceed industry guidance, as set by the ASME Gas Piping Technology Committee Guide for Gas T&D Piping systems. PG&E also repairs, rather than rechecks, above-ground Grade 3 leaks on its distribution system. In 2019, PG&E repaired 130 below-ground Grade 3 distribution leaks to further reduce GHG emissions.

In 2019, PG&E used its continuous improvement approach to more efficiently bundle and schedule leak repairs. Having all the work required in an area at one time provides opportunity to bundle work locations and effectively maximize the utilization of resources. In 2019, PG&E repaired over 37,000 gradable leaks on the gas distribution and transmission system.

In 2019, PG&E also focused on improving Leak Repair effectiveness and efficiency by creating a level-loading approach, managing the average days open for gradable leaks rather than the inventory of Grade 2 leaks at the end of the year. PG&E's Leak Grading and Response procedure requires Grade 2 leaks to be completed within 12 months of discovery. PG&E set an internal target for average age of open Grade 2 leaks of < 150 days and exceeded that goal with the average days open of 96 days for 2019.

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

Figure 34 – PG&E's Maintenance & Construction Crew at Work

l) Overpressure Elimination Initiative

A pipeline that operates at higher than the MAOP presents an operational risk to the safety of the public, employees, and contractors working on the facilities. When a pipeline operates above its MAOP, it is known as an abnormal operating condition and is described as an overpressure (OP) event. OP events have the potential to overstress pipelines and may lead to loss of containment. Large OP events (see Figure 35) pose significant safety and operational impacts to PG&E's gas system. In 2012, PG&E began an initiative to eliminate system OP events and reduce operational risk. In 2016, PG&E identified human performance and equipment failure as the two most common causes for OP events. Actions to eliminate OP events were implemented including: station design and construction best practices; lock-out/tag-out process improvements; and distribution of information around associated OP risk factors through training and communication initiatives.

PG&E's overpressure management achieves top quartile results among benchmarked domestic pipelines.

In 2017, the focus on corrective actions was again directed at human performance and equipment failure. Human performance training was rolled out to PG&E's Gas leadership, with communication targeted at sharing OP elimination strategies. PG&E continued to install SCADA points to increase system real-time visibility in the Gas Control Center (GCC); along with installing sulfur filters on pilot-operated equipment. An extensive benchmarking effort with European operators plus a review of European regulations led to the development of a strategy that supports the goal to eliminate OP events with the deployment of a secondary

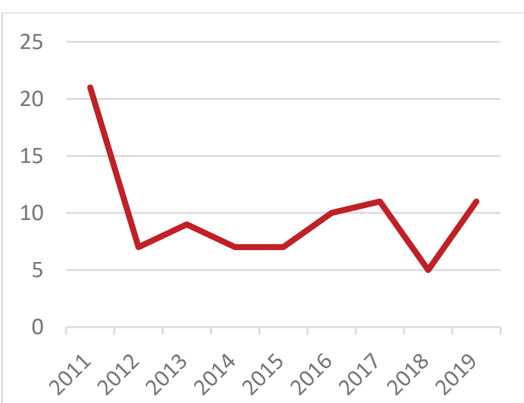


Figure 35 – Large OP Events

overpressure protection device under certain conditions. Large Volume Customer primary regulation sets also received accelerated inspections.

In 2018, PG&E began its strategy to install secondary over pressure protection devices on pilot-operated regulation equipment. PG&E has a strategic goal of installing secondary overpressure protection devices at 50 percent of our pilot-operated sites by the end of 2022. The reasons why pilot-operated regulation equipment is particularly vulnerable to large overpressure events are twofold: (1) they can fail due to gas quality issues, such as debris, sulfur, liquids, or black powder; and (2) they tend to have a design that causes both the regulator and the monitor to fail in an open position, therefore resulting in a loss of regulation.

PG&E currently has 1,511 distribution pilot-operated stations and 292 transmission pilot-operated stations. At the end of 2019, PG&E had a total of 347 pilot-operated stations in which a secondary overpressure protection device has been installed.

At the end of 2018, the NTSB published a Safety Recommendation Report in response to a September 2018 overpressure event in Merrimack Valley, Massachusetts, also known as the Merrimack event. The recommendations in the NTSB report focused on the specific causes of this event, including implementation of professional engineering review, record completeness, management of change process, and additional control procedures during operations. For PG&E's low-pressure systems, the approach to reduce the likelihood of a Merrimack-type event and other reasonable possible drivers of an overpressure event is to augment code-required pressure control and overpressure protection devices (first layer) with a slam-shut (second layer) that is activated by high and low pressure. PG&E's view is that overpressure events can be caused by several different drivers, which can include design-related issues similar to the Merrimack event, equipment-related causes, construction activities, third-party damage, and human performance issues during maintenance. PG&E's strategy is to protect our asset and operations against all possible modes of failure.

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 overpressure elimination. The plan is for the Roadmap to be updated annually.

PG&E continues to modify operations and upgrade gas system regulation equipment to provide greater separation between normal operating pressures and the MAOP. Each activity builds on the goal to eliminate OP events, thereby contributing to system safety.

m) Community Pipeline Safety Initiative

The shareholder-funded Community Pipeline Safety Initiative (CPSI) focuses on enhancing safety above and around PG&E’s gas transmission pipelines. In December 2013, the program conducted a comprehensive centerline survey that allowed PG&E to precisely locate and monitor its gas transmission pipelines and input the data into a new Geographic Information System (GIS). Based on the survey results, we identified approximately 1,553 vegetation miles and 360 structure miles with items located too close to the pipeline. When structures and vegetation are located too close to the pipeline, they can delay critical access for first responders and safety crews or potentially cause damage to the pipeline. The program was initially anticipated as a five-year initiative ending in December 2017, but has been extended through December 2020 due to long-lead permitting and outstanding customer agreements. To date, the program has cleared approximately 1,542 vegetation miles and 359.72 structure miles. The remaining 9.27 miles of vegetation and 0.28 miles of structure clearing is expected to be completed in 2020. The remaining CPSI projects include:

- **Structure Projects:** The remaining structure projects are located in the cities of Palo Alto and Lafayette.
- **Vegetation Projects:** The team continues to work with the cities of Palo Alto, Lafayette and San Jose (District 6) to determine a path forward for this work. In addition, PG&E is working through the coastal process with Santa Cruz County, San Mateo County and Half Moon Bay. PG&E is also engaging with private property owners to reach agreements for this work.

VEGETATION MILES ADDRESSED

	Act + Fcst	%	Complete
2013	115.0	7%	115.0
2014	146.0	17%	146.0
2015	380.0	41%	380.0
2016	540.0	76%	540.0
2017	258.0	93%	258.0
2018	86.7	98%	86.7
2019	18.6	99%	16.57
2020	8.7	100%	0.0
Total	1,553.0		1,542.27

of 11/14, over 99% of vegetation miles have been addressed

STRUCTURE MILES ADDRESSED

	Act + Fcst	%	Complete
2013	5.0	1%	5.0
2014	110.0	32%	110.0
2015	93.0	58%	93.0
2016	114.0	89%	114.0
2017	30.0	98%	30.0
2018	7.6	99%	7.6
2019	0.25	99%	0.12
2020	0.15	100%	0.0
Total	360.0		359.72

As of 11/14, over 99% of structure miles have been addressed

Figure 36 – Overall Community Pipeline Safety Initiative Program Metrics (2013-2020)

Going forward, PG&E is committed to continuing to work with customers to keep the area around the gas pipeline safe and clear, as part of PG&E's ongoing pipeline Operations and Maintenance program.

Operations and Maintenance

Following the CPSI, PG&E's gas operations and maintenance program continues monitoring the area above and around the gas transmission pipeline. This includes looking for any brush, re-sprouted vegetation, newly planted trees or structures, and to confirm none of the trees left in place as part of CPSI have developed into a safety concern.

This program includes patrolling at least one-third (approximately 2,270 miles) of the gas transmission pipelines each year. Vegetation and structures found through these patrols are worked the following calendar year. In 2019, crews patrolled approximately 2,205 miles of gas transmission pipeline. In addition, vegetation crews cleared approximately 201.6 vegetation miles that were identified through patrols conducted in 2018. This included removing more than 1,200 trees. As part of this program, PG&E removes the vegetation at no cost to the customer. The team also addressed 48 structure encroachments. For any structure encroachment identified, PG&E works with the property owner to remove or relocate the structure, at the property owner's expense.

This year, the program anticipates patrolling 3,087 miles of gas transmission pipeline and clearing 300 vegetation miles. Vegetation miles may include treating previously cleared trees that have re-sprouted, removing brush or addressing new plantings. The team continues to work with property owners regarding nine encroachments that were not successfully addressed last year. The team will work with property owners throughout the year as additional structure encroachments are identified.

6. Mitigating the Risk of Loss of Supply

In 2018, PG&E transported and delivered about 1,039 billion cubic feet of gas.[28] 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 Pressure and Capacity

PG&E designs and operates its gas system to ensure safe pressure regulation and adequate gas supplies. PG&E continuously monitors the pressure of its system [see Section IV.7.a *Gas System Operations and Control*]. Additionally, PG&E measures and works to reduce overpressure incidents. PG&E's gas systems are designed to meet all expected core demands (residential and small commercial customers), with non-core demand (large commercial, industrial, or institutional customers) assumed fully curtailed, at a design temperature that is the coldest temperature that may be reached once in every 90 years (referred to as an Abnormal Peak Day, or APD). Also, PG&E's gas systems are designed to meet all expected demand, core and non-core, at the coldest temperature that may be reached once in every two years (referred to as a Cold Winter Day, or CWD).

PG&E's gas system was successfully tested in real-time in December 2013, when it experienced two days below the one-day-in-two-year CWD standard. Sacramento experienced temperatures below the CWD criteria for five consecutive days. However, PG&E was able to provide continuous gas service to all core customers and, consistent with system planning, requested curtailments of up to 61 non-core customers, whose rate agreement includes a curtailment provision.

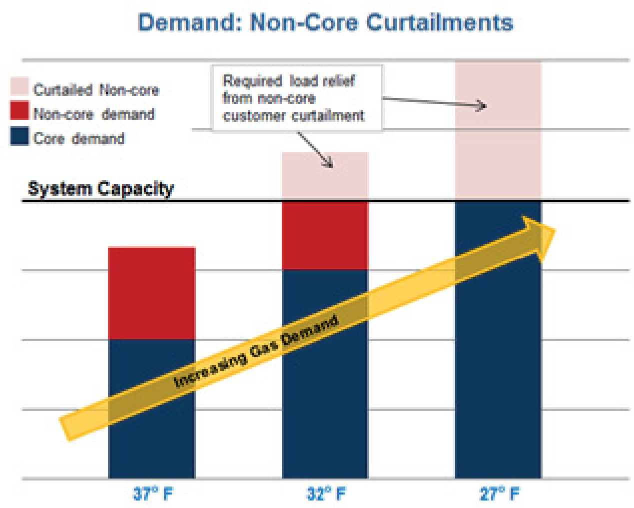


Figure 37 – How Demand for Gas Affects Capacity

Insufficient capacity can result in reliability issues that pose significant public health and safety risks. For instance, a lack of pipeline capacity could lead to a loss of gas service that customers depend on for daily life activities including space heating, water heating, and cooking. In very cold weather, loss of space heating can itself be life-threatening and can prompt customers to use unsafe heating alternatives. Loss of gas service can also lead to extinguished pilots and the subsequent potential for uncombusted gas entering affected buildings. In some scenarios, loss of gas service due to insufficient local pipeline capacity could affect electric generation, which could also result in health and safety concerns.

PG&E drives the quality of its planning effort through a matrix of tools, processes, personnel, standards, internal and external data, and documentation that provides the appropriate level of oversight and control to its management team.

b) Operations Clearance Procedure

An important part of public and employee safety is the use of the Gas Clearance procedure. The Clearance procedure provides an added safety step or layer of protection to confirm that a plan and procedure to protect employee and public safety is in place before work is performed on the gas system. The Clearance Procedure is used for all work that impacts gas flows, pressures, remote monitoring and control, or gas quality. All clearances are approved by Gas Control.

In 2019, Codes and Standards updated the A-38, Purging Gas Facilities Standard.[29] The GCC clearance team worked with Codes and Standards to further develop and implement A-38 into the clearance process. This process for taking out and returning to service is critical to safety of PG&E personnel and customers. A written purge plan included with a clearance is now required, with clearance sketches, to illustrate purge control points and purge point locations. The GCC uses these tools to ensure system integrity and to mitigate situations that could result in the loss of supply to our customers.

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 loss of supply, PG&E is prepared to respond to and recover from incidents. PG&E's policies and procedures have been revised to provide effective 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 manmade emergencies such as fires, floods, storms, earthquakes, cyber disruptions, and terrorist incidents;
- Respond rapidly and effectively, consistent with the National Incident 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.

Objective	Description
Establish Command	Determine the Incident Commander, set up an Incident Command Post (ICP), activate Emergency Center(s), if necessary
Assess Situation	Gather information about emergency, assess the situation in coordination with appropriate 911 agency(ies) and PG&E GCC
Make Safe	Make area safe for public, employees and others
Communicate/Notify	Communicate to/notify the appropriate PG&E personnel, regulatory agencies, public agencies such as fire, police, city and county emergency operations, GCC, customers and media
Restore	Restore gas service
Recover	Deactivate ICP and/or Emergency Centers and return to business as usual

Figure 38 – Key Incident Response Objectives

PG&E uses the structure of the Incident Command System to complete key steps in responding to incidents. The key incident response objectives in Figure 38 represent a typical process flow through the cycle of an incident. However, incidents may not necessarily follow this exact sequence. For example, it may be appropriate to "Make Safe" at several points during the response process and not just after "Assess the Situation."

The next section discusses 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 GCC monitors and controls the flow of gas across PG&E's system 24 hours a day, 365 days per year, so that natural gas is received and delivered safely and reliably to customers. The GCC provides near instantaneous visibility on the gas system. This allows PG&E to prevent, quickly react to, and mitigate issues that may pose a safety risk to the public and PG&E employees.

Figure 39 – PG&E's Gas Control Center Features a 90 Foot-Long Video Wall With Current Operational Information to Augment The Gas SCADA System

PG&E's Gas Transmission Control Center, Gas Distribution Control Center, and Gas Dispatch functions are co-located in a single facility. The co-location of these three functions enables the company to better communicate, share information, and monitor the systems to provide superior emergency response coordination. This visibility, monitoring, control, and response capability is important to PG&E's Gas Safety Excellence vision. For the GCC to be effective, a key control need is situational awareness—the ability to identify, process, and comprehend the critical elements of information about what is happening. Billions of data records, composed of a mix of near real-time gas system operational data and a variety of geospatial, time dependent, and historical information that relates to the gas system provide critical information to Gas Control to aid in decision-making. This data interacts with alarms to focus the operators' attention on abnormal situations. They are also bundled to display clear information to operators so they can quickly assess a developing issue.

Transmission	19.6K Transmission SCADA points[1]	100% Visibility into Transmission system Backbone	57% Visibility into Transmission local transmission	115 Transmission Devices installed 2011-2019
Distribution	27.6K Distribution SCADA points[1]	66% Visibility into Distribution system		1,626 Distribution Devices installed 2011-2019

(1) **Note: PG&E is in the process of evaluating and implementing different measures to represent the extent and capabilities of the SCADA system with the intent of improving the clarity and meaningfulness of this table's information. In some cases, future year categories and their respective values may differ from those currently shown.**

Figure 40 – PG&E's Progress in Enhancing System Visibility Through SCADA

b) Cyber Security

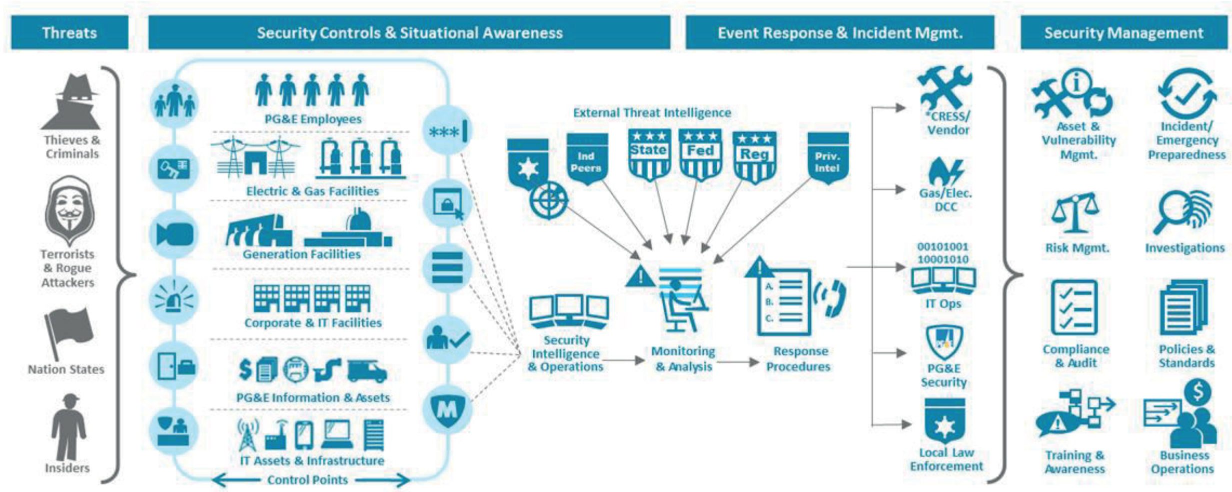
PG&E's commitment to security directly contributes to our mission to deliver safe, reliable, affordable and clean energy. PG&E's natural gas operations incorporate significant risk management activities, including those that address cyber-attack threats. PG&E's Cybersecurity organization advises Gas Operations on cybersecurity risk remediation and mitigation activities to protect information and operational technology, with a focus on control systems. PG&E's gas control systems are considered critical digital assets, and therefore require higher levels of protection through security controls and mitigation improvements. Security controls and mitigation investments are reviewed and updated on an annual basis.

PG&E Cybersecurity's mission is to deliver and maintain an integrated program to safeguard PG&E digital assets by:

- Identifying cybersecurity risks and defining mitigating strategies
- Building, deploying, and operating effective security technologies and processes
- Proactively monitoring for and responding to cyber-threats
- Collaborating with public and private entities to drive standards and best practices

Figure 41– Examples of Active PG&E Government Partners

PG&E's Security Program (which includes both cyber and physical security aspects) effectively manages security risks and proactively adapts to evolving threats and changing business needs. The Security Program, based on industry best practices, is designed to enable informed risk decision making necessary to support the safe, reliable, affordable, and clean delivery of energy to customers.



*CRESS is Corporate Real Estate Strategy and Service

Figure 42 – PG&E Unified Cyber/Physical Security Program Effectively Manages Risk and Proactively Adapts to Evolving Threats and Changing Business Needs

PG&E uses industry best practices, such as the National Institute of Standards and Technology Cybersecurity Framework, to ensure cybersecurity controls and mitigations are suitably robust to identify, protect, detect, respond, and recover from cyber-attacks.

The PG&E Security Program also applies a defense-in-depth strategy with layered controls, so assets are deployed with multiple protections at each layer of the technology stack (network, application, endpoint or host, data, and physical).

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 the 2019 PG&E GridEX V Functional Exercise. This two-day exercise for utilities and other stakeholders from North America provides an opportunity for the organization to exercise how it would detect, respond, and recover from simulated severe cyber and physical attacks. Participants simulate internal and external operational activities as they would during an actual event. Exercise objectives include the following: exercise incident response plans; expand local and regional response; engage critical interdependencies; increase supply chain participation; improve communication; gather lessons learned; and engage senior leadership. It is through the results of security exercises that PG&E is better able to identify and plan control improvements that strengthen Gas Safety.

PG&E's Security Awareness and Training Program is an enterprise security strategy focused on maintaining and strengthening the security culture at PG&E. Regular security communications 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 on security standards, best practices, tips, and risks, and 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, and ultimately reduces security risk.

Protecting PG&E from ever-changing cybersecurity threats landscape enables us to conduct our work in a secure manner that protects our customers, employees, and assets.

c) 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. 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. PG&E's control room personnel have received training to develop a "bias for action." This training helps them recognize and act on system conditions warranting immediate isolation of pipeline systems and planned SCADA installations to continue to increase system visibility are ongoing [see Section IV.7.a. *Gas System Operations and Control*].

The Valve Automation Program builds 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 starting in 2011 for a total of 337 through 2018. In 2019, an additional 23 valves were automated through the Valve Automation Program. PG&E plans to pursue automating 80 valves between 2019 and 2022.

d) Emergency Preparedness and Response

PG&E's Gas Emergency Response practice is documented primarily in the Gas System Operations Control Room Management Manual and the Gas Emergency Response Plan (GERP).

i. Gas System Operations Control Room Management Manual

Gas Control is responsible for the overall operation of PG&E's gas system, and therefore closely monitors and coordinates emergency notifications, dispatching, system isolations, and restorations.

Gas Control personnel primarily use SCADA system data to monitor and control critical assets remotely. The SCADA system alerts Gas Control of gas system irregularities via alarms. When these alarms go off, 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.

To maintain compliance and 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. For 2019 changes to PG&E's Gas System Operations Control Room Management Manual, please see Attachment 2.

ii. Company Emergency Response Plan

The purpose of the Company Emergency Response Plan (CERP) is to assist the gas and electric businesses with a safe, efficient, and coordinated response to an emergency. For changes to PG&E's CERP, please see Attachment 2.

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 Emergency Response Plan

The GERP[30] 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 LOB emergency response plans, which are annexes to the CERP. For 2019 changes to PG&E's GERP, please see Attachment 2.

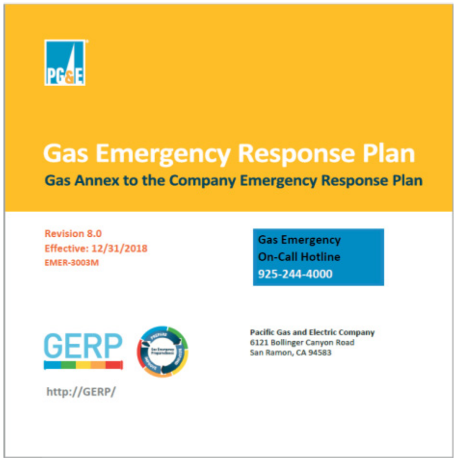


Figure 43– The Gas Emergency Response Plan as of December 31, 2019

The GERP provides an outline of the Gas Operations 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 GERP 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.). To ensure a consistent and well-coordinated response to emergencies, the Company has adopted the following incident classification system:

- Incident Level 1 – Routine
- Incident Level 2 – Elevated
- Incident Level 3 – Serious
- Incident Level 4 – Severe
- Incident Level 5 – Catastrophic

iv. Gas Emergency Preparedness Team

The Gas Emergency Preparedness Team assists Gas Operations with emergency planning, preparedness, response, and review. This group maintains the GERP, leads 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 centers, called Operations Emergency Centers, and the Gas Emergency Center, which is co-located with the GCC. These centers are activated according to criteria outlined in PG&E's GERP.

Throughout 2019, the Gas Emergency Preparedness Group:

Conducted 36 instructor led trainings	Facilitated 15 Operations Emergency Center exercises
Facilitated 3 Gas Emergency Center exercises (which included senior leadership participation in command and general staff Incident Command System roles)	Supported the response to 13 emergency activations requiring activation of the local operations emergency center

Frequent outreach to first responders helps strengthen how PG&E coordinates when emergencies happen. In 2019, Public Safety Emergency Preparedness completed the following efforts in partnership and close coordination with first responders and local governments:

Figure 44 – Delivered 391 First Responder Workshops to more than 8,000 first responders. These workshops train First Responders to safely respond to gas and electric emergencies and exactly how to access the PG&E gas transmission pipeline mapping system.

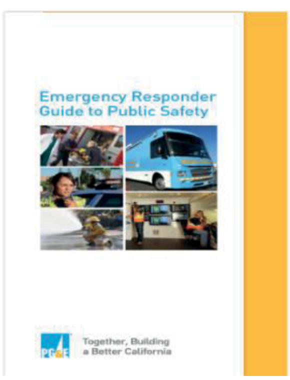


Figure 45 – Met with the 370 fire departments responding to gas incidents. These meetings focused on contingency plans in the event of an emergency.

Figure 46- Hosted two Public Safety Liaison Meetings across the service territory to share PG&E's emergency response plans. Representatives from federal, state, county and city governmental agencies attended these meetings.

Figure 47 – Public Safety Emergency Preparedness attended and presented Public Safety materials for both gas and electric at 21 Safety Fairs and Conferences reaching over 4,600 people, including first responders and the public.

Figure 48 – Supported over 65 incident response activities (including dig-ins). Public Safety Emergency Preparedness acted as an Agency Representative between PG&E and the first responder community.

Figure 49 – Supported 177 811 Dig-In Reduction and safety-related activities in collaboration with the Damage Prevention team to improve safety within PG&E's communities and reduce the incidents of third party dig-ins.

V. WORKFORCE

PG&E's work requires well-trained personnel to correctly perform work activities. As a result, the Company invests in recruiting and retaining, provides ongoing development and training, and maintains supportive controls for employee and contractor work.

For example, employees are required to don the appropriate Personal Protective Equipment (PPE) when they are in the field. Employees can refer to PG&E's PPE Matrix which documents the minimum PPE required when performing a certain task. 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 Job Site Safety Analysis (JSSA) form. In 2018, PG&E revised the JSSA document to include SIF checklists and additional guidance for control measures.

PG&E's PPE Matrix and JSSA are vital resources for employees as they plan their work prior to executing in the field.

Well-trained, fully-engaged employees are a key component of 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 Operations engages the Workforce Planning function and Human Resources partners to determine the appropriate workforce size and types of roles that are required to fulfill our annual work objectives. We recruit qualified and talented employees and, at times, rely on the unique 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 each of our employees has the knowledge to perform his or her job safely and confidently. Safety training starts on day one as part of new employee orientation and continues throughout each employee's career.

2. Workforce Safety Projects

In 2019, PG&E deployed several projects designed to improve employee safety. The focus was on taking care of employees before an injury gets worse. The following summarizes the proactive measures taken by Gas Operations in 2019 and the their progress and successes:

RSI Guard – Gas Operations activated the RSI Guard software on employee computers and enabled set break/microbreak frequency to promote breaks, stretches and microbreak awareness to perform computer work in a healthy and safe way. Gas Operations performed at 94 percent overall break compliance in 2019.

Nurse Care Line – If an employee feels any pain or illness, they are encouraged to call the Nurse Care Line (NCL) for medical advice which can reduce the severity of an injury, if treated early. Employees are increasingly reporting injuries within the first day through the Nurse Care Line and is reflected in the increase in timely reporting for Gas Operations since 2013 (as seen below):

Table 23 – Gas Operations - NCL Timely Reporting

							2019*
Total	61.8%		63.1%	69.5%	74.0%		80.8%

*As of 12/29/2019

As a result, the focus on early reporting and prevention has contributed to the downward injury severity and reduction in average cost per claim (see Figure 3 above). While total number of claims has increased since 2013, the majority are minor claims with fewer medical costs. We anticipate this downward injury trend will continue with increased timely reporting, on-site clinic expansion in 2020 and Roaming Emergency Management Technicians (EMT) which will provide more employees with immediate access to medical care.

OPS Utilization – Increased focus on PG&E's OPS engagement and utilization in cities identified as having higher risks and exposures. OPS are trained physical therapists who focus on observing employee biomechanics, ergonomics and risk behaviors that result in identification of corrective actions and recommendations.

Return to Work (RTW) Task Program – PG&E's RTW Program provides transitional, temporary work assignments (for up to six months) to employees whose restrictions cannot be accommodated within their base jobs.

- 91 Gas employees have been placed into task assignments (50 in Can't Get In (CGI) Program) - since August 2017
    - Occupational: 71 Gas employees placed
    - Non-occupational: 20 Gas employees placed

3. Workforce Training

PG&E's Gas Safety Academy in Winters, California is a state-of-the art gas training facility that opened in August 2017. The facility includes a utility village, which provides realistic residential and commercial scenarios for leak survey, leak pinpointing, and emergency response. Other features include an industry-leading M&C flow lab to provide hands-on training for instrumentation and regulation equipment, a construction training area that includes hands-on excavation, shoring, other construction-related activities, and an excavator simulation room.

Figure 50 – A portion of PG&E's Utility Village at the Gas Safety Academy

In 2018, the Gas Safety Academy became certified as a Class A test facility through the Department of Motor Vehicles, so PG&E employees can train and test to obtain their Class A Driver license. In addition, the weld shop at the Gas Safety Academy became an accredited test facility through the American Welding society.

Table 24 – PG&E Number of Courses Developed or Enhanced from 2012 through 2019

2019	112
2018	122
2017	162
2016	214
2015	107
2014	78
2013	88
2012	14
Total	**897**

In 2019, Gas Operations trained approximately 20,373 student days, including technical, apprentice, and leadership. As of December 31, 2019, PG&E had developed or enhanced 897 courses since 2012 (Table 24). PG&E continues to enhance and continuously improve the training, so that all classifications in Gas Operations have initial and refresher training. For example, in 2019, the Gas Service Rep (GSR) training program was revised to include both classroom and structured on-the-job training. Throughout 2019, PG&E Academy partnered with the Gas Qualifications Department to prioritize and create Operator Qualification refresher training to ensure a skilled, qualified, and competent Gas Operations workforce.

In addition to providing employees training, PG&E Academy partnered with the Gas Public Safety department to develop gas safety training for emergency first responders in the 373 fire departments within PG&E's gas service territory.

The goal of PG&E Academy is to continuously maintain our curriculum to ensure it mirrors current safety practices, procedures, regulatory requirements and new equipment in the field. The recommendations in Table 25 are the output of a partnership between the LOB, SMEs, and PG&E Academy. The importance of the partnership is to ensure that PG&E Academy's projects are aligned to Gas Operations key initiatives and high-risk, high consequence tasks utilizing SME expertise to ensure that the training mirrors actual field conditions and scenarios. The purpose of the partnership is that employees are trained to be safe, competent, and compliant to effectively perform the job task or function trained.

Table 25 – Gas Operation Training Recommendations 2012-2019

2012 Recommendation	Progress as of Dec 31, 2019
Develop programs that support employees throughout their career	• Courses were 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	• Tablets deployed at new Gas Safety Academy. • A Virtual Learning (VL) studio was commissioned and placed in service at the Gas Safety Academy in Winters. Additional topic areas were taught as VL in 2019 – which reduces non-productive time and travel costs and increases consistency and quality of procedural updates and training.
Implement continuous training improvement processes	• The Gas Operations Training Governance Committee has continued to review and approve all redesigned and new curriculum and training requirements • Training Effectiveness studies in partnership with Quality Management and Operator Qualifications teams to determine how effective key training programs are and how to improve them. • The Academy partnered with the LOB and the Gas Qualifications department to develop technical training and qualification profiles for Gas Operations employees to ensure consistency amongst job classifications and to provide line of sight into who is trained and qualified to perform the work.

4. Gas Operator Qualifications

PG&E's Gas Qualifications Department maintains and implements qualification programs covering welding, plastic pipe joining, and operator qualifications pursuant to federal and state regulations and industry best-practices.

PG&E requires that all employees, contractors and third-party installers of pipelines be appropriately trained, and possess all requisite qualifications to perform tasks on pipeline facilities. A qualified operator has the expertise to complete work correctly and is part of the team that helps PG&E meet its commitment to public and employee safety.

Figure 51 – Employees Taking Written Operator Qualification Exam

Pipeline tasks require specific competencies to be performed safely and reliably. These competencies are reflected in the "Knowledge, Skills, and Abilities" (KSA) needed for each task; KSAs are determined by a group of SMEs specific to each topic. An individual's KSAs are assessed via a combination of written and performance (practical demonstration) evaluations and candidates must score 100 percent on each component of an exam to be "qualified." Evaluations are primarily geared towards safety and recognizing and addressing AOC. Qualifications must be renewed every six months, one year or three years depending on the task and applicable regulations.

The CPUC's GO 112-F added new construction activities to the federal definition of covered tasks, effective in 2017. This rule change expanded PG&E's list of tasks for which a qualification is required. The expansion is a significant development in the Operator Qualification Program and involves PG&E employees, contractors, and third-party installers working on PG&E pipeline assets. PG&E enforced the new construction qualifications on January 1, 2019.

Personnel in training gain hands-on experience working under the direction and observation of a qualified individual. Working under the direction and observation of a qualified person allows a person in training to practice his or her skills in real-world conditions and gives the qualified person the opportunity to advise, to correct, and if required for safety, to take over the performance of the task.

By maintaining a qualified workforce, PG&E is in position to quickly and competently recognize and respond to any AOCs that may pose a threat to the safety of the public, employees or assets.

PG&E's Gas Qualifications Department actively participates in benchmarking and process improvement initiatives with other utilities and other industries across the country to continuously find ways to increase the expertise of the workforce. Currently, PG&E is a voting member on an ASME industry best practice standard, called Pipeline Personnel Qualification,[31] which aims to further improve the regulations covering gas industry qualifications.

5. Contractor Safety and Oversight

Contractors are an important aspect of PG&E's technical workforce. Since contractors often work with PG&E's assets and infrastructure that directly impact employee and public safety, the Company holds contractors to the same standard of safety as PG&E employees. The CPUC's Safety Culture OII proceeding (I.15-08-019) included a report that evaluated PG&E's safety practices, including those in Gas Operations. The report recommended that the Gas organization update the contractor safety procedure to clarify responsibilities and reflect current organizations and processes, including guidelines regarding frequency of field observations. As a result, PG&E revised its Contractor Oversight Procedures in 2019.[32] The revised procedures will continue to follow a four-step process (Figure 52) for contractor safety and oversight. Other revisions included updates to various responsibilities (Competent Site Representatives and Project Team), enhanced the contractor safety observation criteria, and added requirements for PG&E Safety Representative.

Figure 52 – Four Step Process to Contractor Safety and Oversight

Prior to starting a job, PG&E *pre-qualifies* contractors and subcontractors, and confirms they are qualified to complete the contracted work through internal and third-party (ISN) reviews. PG&E continues to improve its contractor pre-qualification process and update 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 Quality Assurance (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. Figure 53 provides 2019 metrics on injuries and motor vehicle incidents. In 2019, PG&E Construction Crews and Contractors outperformed in all performance metrics with the exception of OSHA recordable incidents when compared to PG&E as a whole, and worked over 5 million hours performing higher risk work.

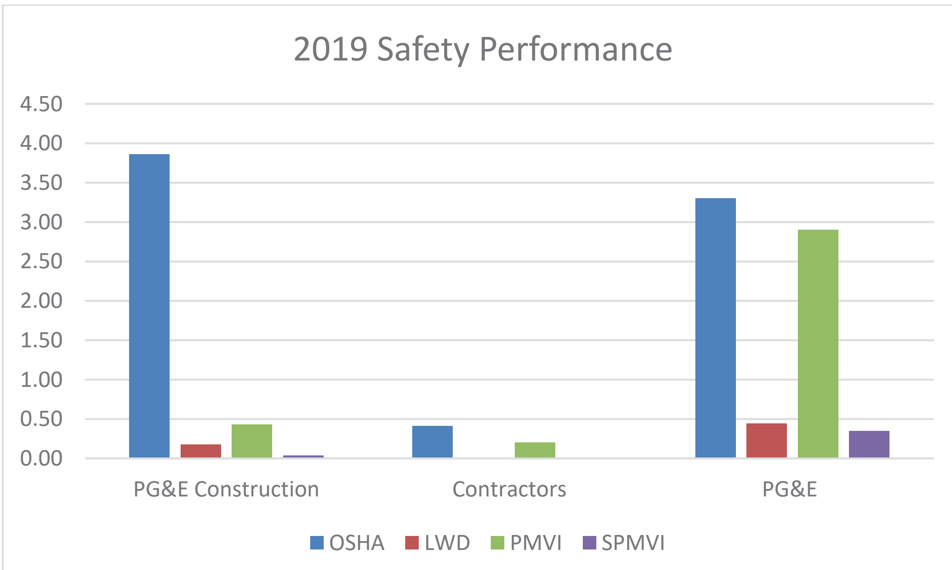


Figure 53 – 2019 Gas Safety Performance

Year-over-year reductions in all four categories show the shift in safety behaviors and culture for Strategic Partners. As depicted in Figure 54, the data demonstrates that between 2017 through 2019, OSHA recordables (ORI) had fluctuations between 2017 and 2019 with a dip in 2018. Lost Work Days (LWD) have trended downwards. Motor Vehicle Safety has improved in 2019 with reductions in Preventable MVIs and Serious Preventable MVIs. Development of a backing/spotter plan has helped reduce the number of backing incidents in 2019, which contributed to the lower rates.

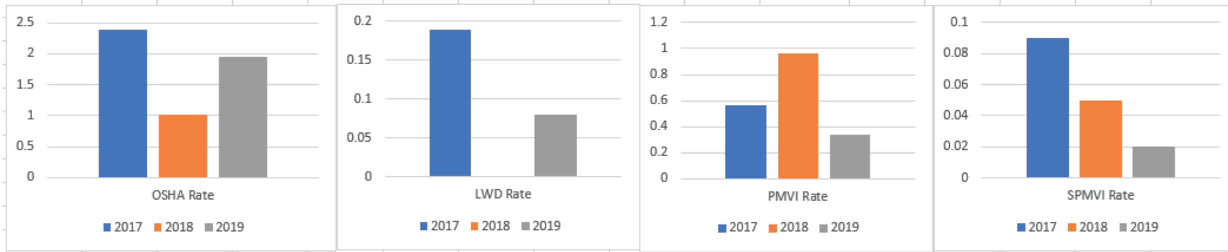


Figure 54 – Strategic Partner Safety Year Over Year Performance

PG&E believes that employees who are engaged at work and who feel recognized are far more likely to work safer, be more productive, make better decisions and produce higher quality work.

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 2019, there was an up-tick to over 909 quality "Good Catches" turned in to PG&E's safety and construction management function. This is a seven percent increase compared to 2018. Everybody that turned in a "Good Catch" was recognized and the "Good Catches" were shared on a weekly call with all PG&E construction and contractor leadership. Contractors continue to speak up to raise awareness and share best practices.

6. Partnership With Labor Unions

Union-represented employees make up almost 73 percent of PG&E's Gas workforce, and are integral to the Company providing safe and reliable gas service. PG&E frequently 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 2019, PG&E continued to collaborate with union leadership on projects such as improving emergency response and "make safe" times for blowing gas situations, enhanced lines of progression, the affordability initiatives, Estimator in Training Program, Grassroots Safety Committee Partnership, and PG&E's Leak Survey Optimization Program.

The line of progression effort has updated job duties, training and certification for almost every represented field-based position. These changes have driven improved training and certifications for the Company's workforce (NACE certification)[33] for corrosion mechanics, as one example), improving the safe and compliant delivery of service.

VI. Compliance Framework

PG&E transports and stores natural gas under the requirements of state and federal safety regulations. In 2016, PG&E adopted the Compliance Maturity Model to standardize and assess its regulatory compliance processes against industry best practices. The Model is composed of eight elements: risk assessment, program governance, guidance documents, compliance controls, communications and training, monitoring and auditing, investigation and response, and enforcement and incentives. Each element in turn has five performance thresholds. This framework provides Gas Operations a uniform outline from which to assess the performance of PG&E's compliance processes against their regulatory requirements. In 2016, a baseline performance assessment was conducted, and in 2017 the business began the work of aligning federal and state regulatory requirements to our processes and conducted periodic re-assessments against the framework's tiered performance thresholds. In 2019, Gas Operations did not achieve an overall level three for its compliance maturity model. Gaps were identified in all eight elements of the program. A remediation plan will be developed for 2020 to address the identified gaps and focus on areas needing strengthening. Programmatic and process controls are undergoing strengthening to ensure that the business is both compliant with current regulations, as well as prepared to successfully implement new and changing regulations effectively.

The Compliance Maturity Model aims to bring visibility to PG&E's regulatory requirements, validate that controls are in place to meet those requirements, and structure the monitoring and testing of those controls for effectiveness while maintaining adequate programmatic oversight to keep compliance at the core of the work that we do. This approach aligns with the "Plan, Do, Check, Act" management method that PG&E employs throughout its operations as part of Gas Safety Excellence.

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

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

1. Building Expertise

PG&E employees require specialized skills to be able to perform their jobs constructing, operating and maintaining the natural gas systems. As detailed in *Workforce Training (Section V.3.)* and *Gas Operator Qualifications (Section V.4)*, 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.

2. The Right Information to Do the Work

A highly-skilled workforce is most effective when enabled with timely, accurate information from which to work. 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 our service territory, written guidance documents, such as procedures and job aids, are utilized. These documents are stored electronically in the Technical Information Library and are reviewed on a routine basis so that that they reflect both regulatory requirements and best practices, as well as any lessons learned from Company or industry experiences. While this review and revision practice keeps the Company's processes at a state-of-the-industry level, it also requires significant efforts to keep all personnel performing work in accordance with these documents, are made aware of any changes and are provided with the requisite training and provided access to SME to maintain compliance.

PG&E continued the monthly publication schedule to pace the changes experienced by people performing the work, allowing for more time to receive and digest each change to their work between the publication date and the effective date of any given change. E-mail communications are sent out that separates changes based on several categories, allowing employees to more efficiently determine relevant changes.

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, in majority of the cases, detailed information about asset history, materials, manufacturer, and location. These systems help PG&E to 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 in a timely manner. As prescribed in the Compliance Maturity Model, compliance goals need to be accompanied by effective controls and performance monitoring.

3. The Right Resources to Do the Job

Once the correct work has been identified, PG&E determines the number of employees, contractors, and tools needed to complete the portfolio of work efficiently. PG&E maintains agreements with multiple contractors and maintains a database of qualifications in order to assign work to the appropriate resources. PG&E utilizes workplans comparing anticipated level of effort to internal resource capacity in order to signal the need for additional overtime, contractor resources, etc.

4. Supportive Controls

A compliant company utilizes numerous processes and programs to perform at a high level; some are aimed at monitoring or improving internal processes with corresponding compliance requirements and others are aimed externally, to help PG&E identify opportunities for continuous improvement or pending regulatory changes. Table 26 below details some of these processes and programs.

Table 26 – Compliance Processes and Programs
Quality Management (QM) –The QM group assesses and provides direct feedback on the work quality for PG&E's important safety programs, including locate and mark, regulator station maintenance, and as-built record development. [See Section VII.4 *Quality Management*].
Internal Audit (IA) – PG&E's IA team performs arm's length reviews for all the Company's lines of business, including Gas Operations, and is responsible for assessing control adequacy.
Non-compliance Self-Reporting – PG&E is committed to self-reporting compliance issues and taking prompt mitigative and corrective action to prevent recurrence. PG&E filed 3 Self-Reports in 2019 in accordance with the Safety Citation Decision.
Participation in Safety and Enforcement Division (SED) Inspections – In advance of CPUC SED inspections, PG&E self-evaluates gas divisions, districts and programs, such as Operator Qualification, Emergency Management and Integrity Management, and shares findings with the SED. PG&E's assessors spent approximately 11,000 hours in 2019 managing data response issues and supporting resolution. PG&E strives to resolve identified issues within the same inspection cycle and respond to any data requests within the duration of the inspection.
Cause Evaluation – Similar to the continuous improvement mechanism in PG&E's Process Safety management framework, cause evaluations are post-incident investigations that include an incident analysis and recommendations to prevent or mitigate future reoccurrence. Cause evaluations are conducted based on business determination of identified issues. The Gas CAP team completed 56 apparent cause evaluations in 2019.
Evaluation of NTSB Reports – The NTSB investigates all serious pipeline incidents. PG&E SMEs routinely review NTSB reports to learn from pipeline incidents. As a result, PG&E may adopt new approaches to addressing threats, change work procedures or develop new training.
Evaluation of PHMSA Bulletins – PHMSA regularly issues safety advisories for pipeline operators. As new safety information comes to light at other gas companies in the US, PHMSA issues bulletins to help operators take preventative action.

VII. Continuous Improvement

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

1. Gas Stewardship

The Gas Stewardship Office, established in 2017, leads Gas Operations' efforts to drive process performance management conversations and continuous improvement activities into our safety and reliability work, and to create a more affordable, compliant gas system without compromising safety or quality.

Gas Operations has embraced the notion that safety and affordability are not a trade off, but instead can be accomplished at the same time. The Stewardship Office works with key stakeholders within Gas Operations to continually identify process performance improvement opportunities and develop initiatives to implement those improvement plans.

Initiatives are generated from two main sources. First, process teams host ideation sessions to identify opportunities within its process to yield improvements. Second, any employee or contractor can submit ideas through CAP and items are flagged as affordability ideas which are then forwarded to process teams for consideration. Over 400 initiatives impacting distribution and transmission operations are currently being pursued within Gas Stewardship.

In 2017, Gas Operations implemented a tool to track and manage all Gas Stewardship initiatives from inception to completion, and uses the tool to manage progress on continuous improvement initiatives daily. Of the current initiatives being managed within Gas Stewardship, all of them are intended to either improve the safety, affordability, quality, compliance, and/or reliability of the gas transmission and distribution system. The Gas Operations Senior Leadership team performs a three-element review process on all new initiatives, reviewing each initiative to ensure it would not negatively impact safety, compliance or regulatory obligations. In addition, the Stewardship Office along with initiative owners and SME review initiatives with a 10-point filter to account for safety, compliance, regulatory and rate case implications. Initiatives with any potential implications are flagged for further review.

2. Lean Capability Center

In 2017, Gas Operations deployed a Lean Management System across the entire organization. The Lean Capability Center (LCC)[34] was created as the centralized hub to support each of the functions within Gas Operations in their deployment of Lean tools and practices. Lean Management (Lean) is Gas Operations' approach to running Gas Operations now and into the future. It is an integrated system of principles, practices, and techniques for operational excellence based on empowering the front-line, identifying waste in our processes, and finding opportunities to continuously improve, all supporting the relentless pursuit of serving customers better. Lean improves safety, quality, and affordability while enabling meaningful performance conversations up and down the organization.

Lean is a system of complementary tools that are incorporated into the four pillars of our Lean Management system, which are referred to as "loops" because they must happen in continual cycles. These tools are critical to the success of the system.

Figure 55 – Lean Management System in Gas Operations

Examples of Lean tools and practices include: huddles and visual performance management, standard work, waste identification, problem solving, and leader standard work. The LCC is primarily responsible for establishing a consistent Lean deployment strategy for all of Gas Operations, developing Lean curriculum, facilitating training, sharing best practices, building tools to ensure the sustainability of Lean, and supporting the functional teams in their deployment.

Huddles are quick, structured conversations among team members that occur daily or several days a week. Huddles provide a platform for employees to speak up and raise issues, share resolutions and information, discuss progress on metrics and targets at each level, and recognize individuals and/or teams for great work and successes. A huddle board is a visual performance management tool that helps facilitate the huddle discussion. Huddles cascade throughout the organization and follow the same general agenda to ensure consistency. Information is moving more freely than before from front line supervisors to the Executive level, and vice versa. LCC provides expertise, capability building and targeted Lean support. In 2019, the LCC trained 96.6 percent of Supervisors, Managers and Superintendents in Lean through two-day Lean bootcamps. Additionally, the LCC launched Internal "Go & Sees" in Bishop Ranch to highlight "Lean in Action" in Gas Ops and inspire others to use Lean.

Lean Sustainability Reviews (LSR) were designed and implemented in 2019 to assess the health of our Lean deployment throughout Gas Operations. The LCC worked with the functional Lean teams to deploy a single sustainable program that replaced multiple existing Lean tool reviews. The LSR's objective is to identify Lean behavior best practices and opportunities to further develop the use of Lean tools and behaviors at the Manager and Director levels.

Each function within Gas Operations (e.g., T&D Construction, T&D Operations, etc.) has their own Lean team led by a Functional Lean Leader with a team of Lean Coaches. Their role is to install the Lean tools and behaviors in accordance with deployment plans.

3. PROCESS MANAGEMENT

Process Management involves planning, monitoring, and controlling the performance of a business process with the goal of meeting customer and business requirements. Process Management enables individual functions to understand and work towards common process goals. As such, Process Management promotes safety, reduces costs, increases quality and efficiency, and ensures process controls are in place. With a well-defined process, work can also be optimized across functions. Process management involves the application of knowledge, skills, tools, techniques and systems to manage a process. It helps to set up the foundation, where Process Improvement can continue evolving the process performance.

The Process Management Playbook uses a 25-step approach to establish process management, which incorporates Lean principles and includes developing metrics, confirming the right controls are in place, and ongoing monitoring of performance. Process Management efforts focused on processes with a significant impact (those with a high safety and/or quality risk, high number of compliance findings, etc.). In 2019, each process stood up their Tier 3 Huddle (step 13) and a Tier 4 huddle was stood up for all four mega processes. The benefit of these huddles is to provide a venue for Process Owners and Managers to meet with the end-to-end process stakeholders to review metrics and discuss performance, improvements and issues. Additionally, each process created or updated standard work documents (Step 22) and posted them to the centralized and universally accessible Gas Operations Knowledge Portal and 18 of 39 processes completed all 25-steps of process maturity (see Figure 56 below).

Figure 56 – 25-Steps of Process Maturity

Process Management teams include Process Owners (PO), Process Managers (PM), Process Analysts, and other key stakeholders. To assist in on-boarding new POs and PMs, the Improve & Sustain team designed, coordinated and rolled out of Lean Web Based Training and the Process Management Playbook.

As we continue to deploy the Lean Management System, Process Owners with support from the LCC will continue applying the Process Management Framework to improve the maturity of Gas Operations' processes.

4. Quality Management

The Gas QM organization is responsible oversight of all QA activities and support for quality controls into Gas Operations processes in order to maintain desired level of excellence. QA activities include conducting quality assessments in the field and reviewing documentation and records, either as work is being performed or after-the-fact. Both approaches allow for continuous improvement and drive consistency by identifying non conformances, recommending corrective actions and following up with mentoring and coaching people doing the work. There are currently 18 active QM programs as of December 2019 and are shown in Table 27 below.

Table 27 – List of Quality Management Programs as of 2019	
Leak Survey	Post-Repair Leak Survey
Locate and Mark	Distribution Construction
Field Service	Transmission Construction
Valve Maintenance	Regulator Station Maintenance
Corrosion Control	Rotary Meter Installation and Maintenance
Internal Records Review	Gas Transmission and Distribution As-Builts
Chain of Custody	Atmospheric Corrosion Meter Inspections
QA Pipeline Features List (PFL)	Post Construction Asset Validation
Scanning & Attributing	GT Alignment

Continuing the journey to mature the Gas Operations Quality Management System (QMS) and build on continuous quality improvement, field Quality Control (QC) programs were further developed in 2019 within the T&D Construction and T&D Operations organizations. The T&D Construction organization continues its field QC Program, and T&D Operations was able to partially roll out its field QC Program in 2019. The Gas Operations organization continues to increase focus on quality control in order to identify defects early, drive down error rates, and ensure that work performance and documentation is of high quality to meet our safety, compliance, and customer expectations.

The fundamental principles of the QMS leverage the "Plan, Do, Check, Act" (PDCA) framework (refer to Figure 57) that is instrumental to PG&E's implementation of Gas Safety Excellence. PDCA is an iterative four-step management method used in business for the control and continuous improvement of processes and products. Just as a circle has no end, the PDCA cycle should be repeated for continuous improvement.

Figure 57 – The Quality Management System

Accomplishments in 2019 include:

- Performed 4,432 quality assessments in the field and 18,746 in the office.
- Developed and delivered As-Built Job Package quality review training for QC to further knowledge and consistency across QA and QC.
- Implemented standard process to ensure version control across multiple work locations that store Operating Maps and Operating Diagrams.
- Migrated MS Excel/Access data to SQL database creating a single source for quality data and eliminating reliance on multiple data sources.

Due in part to these accomplishments, the QA Field Quality Index metric that provides insights on quality for the key processes in Gas Operations improved from 2018-2019. PG&E saw an approximate 83.4 percent reduction in the number of high findings for QA Field programs. Refer to Figure 58 for 2019 performance, which shows the total cumulative number of 42 high findings for QA Field.

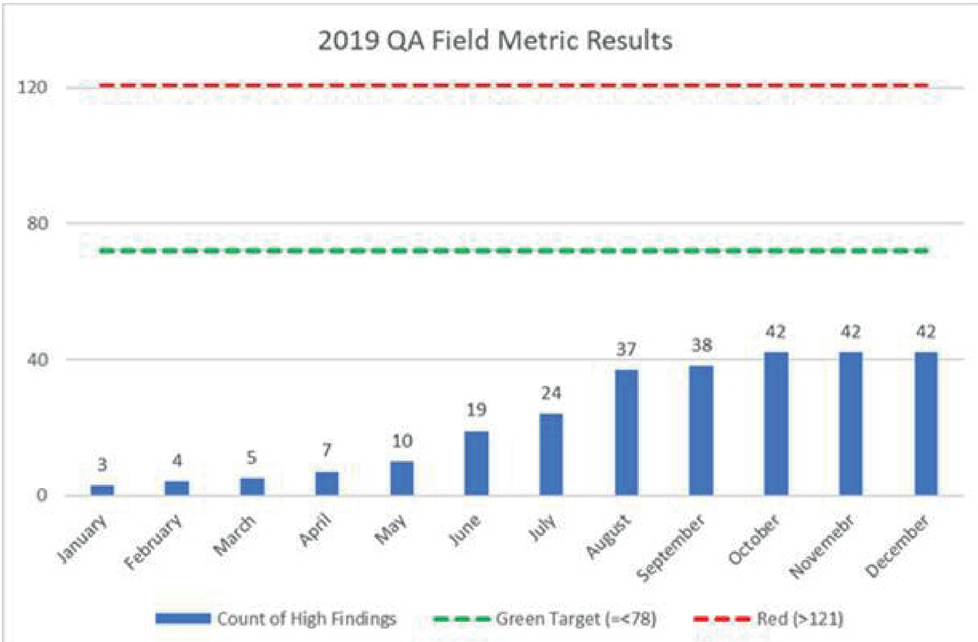


Figure 58 – 2019 QA Field Performance Metric

5. SQA 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 non-conforming 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 2019 DPPM performance was 322 against the target of 292. For 2020, SQA introduced two new DPPM metrics (DPPMs = standard products inspected historically, and DPPMn = newly introduced products to be inspected) which will aid PG&E in refocusing its quality efforts and allow to inspect more products while supporting material risk reduction initiatives. The DPPM target for 2020 is 386.

SQA achieved significant performance since 2013 for quality programs driving supplied material to an ultimate goal of being defect free. Eighty nine percent of PG&E's supply base has achieved third-party

ISO 9001 certification of their QMS. SQA was re-certified to ISO 9001:2015 QMS and had zero non-conformities for all audits. Through PG&E's cross functional teams and supplier partners, SQA processed 477 Supplier Change Requests and eight supplier material recalls. In addition, SQA conducts an annual supplier survey to identify improvement opportunities.

6. RESEARCH AND DEVELOPMENT

The Research and Development (R&D) and Innovation Group brings innovative technologies and solutions from industry, government, and academia to the Gas Operations. PG&E continues to use the Center for Gas Safety and Innovation in Dublin, California which opened in 2017. This facility consists of work and lab space that houses groups within Gas Operations and provides them with advanced tools, testing capabilities and lab resources, with the goal of continuing to lead in the development of new methods and technologies to enhance gas safety. The work performed at this facility includes, among other things, working with other industry participants to find and test new products and processes, testing and evaluating Maintenance & Construction (M&C) devices that contribute to the safety of PG&E's gas system, and conducting Non-Destructive Examination on PG&E's pipelines to ensure asset integrity.

Figure 59 – Insertion of the Explorer In Line Inspection robot in its launcher on line L-105N in Oakland on August 23, 2019

In 2019, the R&D team has continued its collaboration with leading U.S. utilities and R&D organizations to manage and implement a broad portfolio of more than 200 projects.

R&D is embedded in Gas Operations through Gas Safety Excellence and the continuous improvement process. R&D's work is prioritized based on the results of the Risk Management Process, so projects and innovations align with the most critical needs of the business [see Section IV.3. *Risk Management Process*]. Starting in 2019, R&D projects and their results are directly included within each Asset Management Plan to assure that new technologies and methods are effectively leveraged to improve the safety, reliability and cost effectiveness of PG&E's assets.

PG&E participates in collaborative efforts with national and international R&D organizations such as PRCI, NYSEARCH, and Operations Technology Development (OTD)/Gas Technology Institute. PG&E also works closely with R&D programs at the California Energy Commission, PHMSA, the CARB, the Department of Energy and multiple universities including Stanford (through the Natural Gas Initiative), UC Berkeley, UC Davis, UC Irvine, etc.

Examples of milestones reached in 2019 include:

- The HYREADY project led by 20 European and North American gas utilities has developed industry guidelines addressing the 'how-to' questions for gas system operators so they can be confident both in preparing their natural gas grids for the accommodation of hydrogen and in assessing and managing the effects and possible consequences related to hydrogen injection. The guidelines for the natural gas transmission and distribution system as well as for end use equipment and appliances have been completed in 2019. Guidelines for compressor equipment and storage is future work.
- The paperless material traceability and as-built application for gas distribution has been developed in collaboration with American and Canadian utilities through the OTD R&D consortium for several years, in 2019 the solution was finally deployed with Gas Construction for the reconstruction of Paradise recording electronically the installation of more than 25 miles of mains and services including 17 miles of joint trench and eliminating the associate paperwork.
- The Explorer line of robots has been collaboratively developed through NYSEARCH since the mid-2000 to inspect portion of pipelines inaccessible to traditional smart pigs. In 2019, PG&E hosted of the first live demonstration of two new major advancements of this product: the ability to automatically perform a hardness testing within the pipeline to confirm its grade and to harvest energy directly from the flow of gas to charge its battery and expand its inspection range.

Finally, the industrial product of the ultrasonic device design to detect plastic inserts in steel pipelines mentioned in the 2018 Gas Safety Plan has been completed and is being tested in the field to demonstrate its long-term performance.

Figure 60 – Capturing material information and geometry of a Joint Trench Project during the reconstruction of Paradise on June 4, 2019.

7. 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 and discussing with other utilities. 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 next sections.

a) Industry Standards Written by SMEs

One informal benchmarking practice that PG&E pursues is identification and use of 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 that particular 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 has adopted for use several European standards. In another example, PG&E pursued the certification of ISO 55001, the international asset management standard, and has both achieved and sustained certification.

PG&E relies on associations such as the ASME and the API, to facilitate the development of best practices, 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, 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, the NTSB, PHMSA, and reviewers contracted by these entities.

As an example, PG&E has a procedure to ensure 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 organizations such as the INGAA, AGA, NACE International (formerly known as the National Association of Corrosion Engineers), API, ASME, Southern Gas Association, Public Service Enterprise Group (PSEG), the Common Ground Alliance and other organizations.

PG&E employees participate in and present 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. Some of the peer-to-peer associations PG&E participates in are described below in more detail.

d) American Gas Association

As part of PG&E's continuous improvement commitment to safety in Gas Operations, the Company is an active member of the 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 participates in the AGA SOS Survey Program by both distributing and responding to surveys with topic-specific information requests throughout the year and utilizes the data provided by other U.S. utility gas companies.

e) Interstate Natural Gas Association of America

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 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 relies on INGAA to facilitate the identification, development and sharing of best practice materials.

f) NACE International

PG&E also relies on NACE International to identify and develop standards, test methods and material recommendations that are widely regarded as best in the field of corrosion and specifically for CP and coatings. NACE International creates these materials through the subject matter expertise of its members. NACE International has over 28,000 members in over 100 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, information about industry best practices and skills training. PG&E also participates on several committees.

h) Public Service Enterprise Group

The PSEG is a publicly traded diversified energy company headquartered in Newark, New Jersey and was established in 1985. The company's largest subsidiary is Public Service Electric and Gas Company (PSE&G).

The Gas and Electric Utility Peer Panel was established in 1993 and is a collaborative effort between member utility companies that focus on sharing benchmark data on an annual basis.

PSE&G developed the panel of companies for exchanging accurate and meaningful data on key performance metrics.

i) Additional Benchmarking Efforts

In addition to the numerous associations, PG&E also uses informal means of benchmarking including using the expertise brought to the Company by new-hires and contractors with industry experience, by attending trade conferences, and by information sharing with other utilities.

PG&E also uses benchmarking to facilitate continuous improvement. When possible, PG&E benchmarks metrics to understand performance against peers.

Industry performance also informs target-setting. The following chart lists a few key safety metrics that PG&E benchmarks against other utilities:

Table 28 – Key Benchmarking Metrics

PG&E's Commitment to Safety	Measurement
Emergency Odor Response	Average response time
Year-End Grade 2 Leak Backlog	Per 1,000 miles of mains and services
Year-End Grade 3 Leak Backlog	Per 1,000 miles of mains and services
Lost Work Day Case Rate [(a)]	LWD per 200,00 hours worked
Third Party Dig-In Reduction	Number of dig-in incidents per 1,000 tickets

____

(a) This measure is benchmarked at the Company level.

Comparative data associated with these benchmarks may be protected by confidentiality or non-disclosure agreements.

VIII. Conclusion

The 2020 Gas Safety Plan update demonstrates PG&E's commitment and progress in implementing processes, programs, and procedures to achieve its vision to becoming the safest and most reliable natural gas utility in the nation. The GSEMS 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; investing in the reliability and integrity of its gas system; and, by continuously improving the effectiveness and affordability of its processes. PG&E has made continued progress, but recognizes that there is more to be done in its journey to achieve Gas Safety Excellence.

IX. Endnotes

1 See Attachment 12 for a Table of Concordance that provides a mapping between the Public Utilities Code Sections 961 and 963 and the Gas Safety Plan sections.

2 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 Public Utilities Code §§ 961 and 963(b)(3).

3 See GOV-6101S, Enterprise Corrective Action Program Standard in Attachment 4.

4 See GOV-6101P-08, Corrective Action Program Procedure in Attachment 5.

5 Degree considerations can include: physical harm vs. immediate life threatening; redundancy vs. single point failure; recovery vs. point of no return; local vs. widespread, monetary impact.

6 In 2017, a Federal Court-Appointed Monitor was assigned to PG&E to oversee PG&E's safety performance for the period of PG&E's court-ordered probation stemming from its conviction in connection with the San Bruno incident and resulting NTSB investigation.

7 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.

8 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. Tier A is the most lagging and Tier D is the most leading.

9 See Attachment 6.

10 See Attachment 7.

11 See Attachment 8.

12 See PG&E's 2019-01 Gas Transmission & Storage Safety Report (submitted on August 30, 2019) and PG&E's 2018 Gas Distribution Pipeline Safety Report (submitted on March 29, 2019).

13 American Petroleum Institute (API) Recommended Practices (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.

14 API Recommended Practices (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.

15 The Transmission Pipe asset family includes valves outside of station boundaries and not otherwise included in the Measurement and Control 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.

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

17 See Attachment 3.

18 A non-gas customer receives gas from other means, such as propane or other third-parties. Unlike gas customers who receive gas safety information via bill insert or electronic billing statements, a non-gas customer receives a separate direct mailing.

19 49 CFR §192.614.

20 California Government Code §4216.

21 Investigation (I).18-12-007 Order Instituting Investigation and Order to Show Cause on the Commission's Own Motion into the Operations and Practices of PG&E with Respect to Locate and Mark Practices and Related Matters.

22 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.

23 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.

24 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 IV.5.i.

25 Traditional In-Line Inspection is a term used to refer to in-line inspection tools that run via propulsion by the pressure and flows of the gas stream. Non-traditional in-line inspection methods are also being employed by PG&E under some circumstances where pressures and flows and/or pipeline lengths are too short to feasibly run traditional in-line Inspection tools.

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

27 2017 GRC Exhibit (PG&E-3), Chapter 6C, page 6C-4, fn. 10, "It will never be possible to survey the entire system with the Picarro Surveyor due to Abnormal Operating Conditions (AOC) and physical conditions that lessen the coverage of the technology…" PG&E surveyed one hundred percent of its divisions with the technology in 2018 and in doing so it covered seventy-five percent of the distribution system.

28 PG&E's California Gas Transmission Pipe Ranger website Supply and Demand Archives, https://www.pge.com/pipeline/operations/cgt_supplydemand_search.page. Execute search for 12/31/2019 and preceding 364 days, then add values listed in "Total System Supply" row.

29 See Attachment 8.

30 The GERP complies with CFR Title 49, Transportation, Part 192—Transportation of Natural and other Gas by Pipeline: Minimum Federal Safety Standards,

Section (§) 192.615, "Emergency plans." and (§)192.605 "Procedural manual for operations, maintenance, and emergencies."

31 ASME B31-Q.

32 See Attachment 9.

33 NACE, formerly known as the National Association of Corrosion Engineers, is an international organization focused on developing industry standards for corrosion management, teaching best practices, and researching corrosion issues. NACE provides multiple certificate programs in a variety of corrosion management areas.

34 Created as part of Gas Stewardship and was formerly known as Super Gas Operations (SGO) and Process Excellence. The LCC includes a select group of leaders from the organization to implement the Lean Management System in Gas Operations organization

X. Appendix A – List of Figures

XI. Appendix B – List of Tables

XII. Appendix C – List of Attachments

Attachment 1 – 2020 Leak Abatement Compliance Plan

Attachment 2 – Change Logs for PG&E's Asset Management Plans, Gas Emergency Response Plan, Company Emergency Response Plan, and Gas System Operations Control Room Management

Attachment 3 – Document Number: GP-1109, Data Asset Management Plan, Rev. 1

Attachment 4 – Utility Standard: GOV-6101S, Enterprise Corrective Action Program Standard, Rev. 10

Attachment 5 – Utility Procedure: GOV-6101P-08, Corrective Action Program Procedure, Rev. 0

Attachment 6 – Utility Procedure: TD-4014P-04, Change Control Process for Gas Organizational Changes, Rev. 0b

Attachment 7 – Utility Procedure: TD-4014P-05, Field Design Change Process for Distribution Lines and Dual-Asset Facilities, Rev. 1

Attachment 8 – Utility Procedure: TD-4014P-06, Field Design Change Process for Transmission Pipelines and Transmission Station Designs, Rev. 1

Attachment 9 – Gas Design Standard: A-38, Purging Gas Facilities, Rev. 1c

Attachment 10 – Utility Procedure: SAFE-3001P-07, Contractor Safety Oversight Procedure – Gas Operations, Rev. 5

Attachment 11 – Change Log for 2020 Gas Safety Plan

Attachment 12 – Table of Concordance

VERIFICATION

I, the undersigned, state:

I am an officer of PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, and am authorized to make this verification for and on behalf of said corporation, and I make this verification for that reason. I have read the foregoing 2020 Gas Safety Plan and 2020 Leak Abatement Compliance Plan, and I am informed and believe the matters therein are true and on that ground, I allege that the matters stated therein are true.

I 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 9, 2020.

Christine Cowsert
VICE PRESIDENT, GAS OPERATIONS
ASSET MANAGEMENT AND SYSTEM OPERATIONS
PACIFIC GAS AND ELECTRIC COMPANY

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 1

2020 LEAK ABATEMENT COMPLIANCE PLAN

PACIFIC GAS AND ELECTRIC COMPANY'S 2020 LEAK ABATEMENT COMPLIANCE PLAN MARCH 16, 2020

SECTION A: PLAN INTRODUCTION AND SUMMARY

Meeting the challenge of climate change is central to Pacific Gas and Electric Company's (PG&E) vision of a sustainable energy future. Consistent with our vision, PG&E works to reduce greenhouse gas (GHG) emissions and environmental impacts from our operations, and acts as a valuable partner to do so in California and beyond.

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 related to natural gas leak abatement (phase one). PG&E's Natural Gas Leak Abatement Program includes annual methane emission tracking and reporting as well as the submission of a biennial best practice compliance plan. This 2020 Leak Abatement Compliance Plan (2020 Compliance Plan) is the second biennial Leak Abatement Compliance Plan prepared in accordance with the Commission's decision.

PG&E's 2015 baseline emissions level totaled 3,294,368 thousand standard cubic feet (Mscf). At 2018 year-end, PG&E reported emissions totaling 2,913,208 Mscf. This represents approximately an 9 percent decrease in emissions. In its 2018 Leak Abatement Compliance Plan (2018 Compliance Plan), PG&E saw the largest emissions reductions from these activities:

- Quarterly leak surveys at PG&E's compressor stations and storage facilities (as required by the California Air Resources Board (CARB) Oil and Gas Methane Regulation (California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Sub article 13 – Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities referred to as, the CARB Oil and Gas Rule, which led to the identification and repair of more leaks.
- Accelerating leak surveys to a three-year cycle consistent with Best Practice 15. This enabled PG&E to find and fix leaks sooner.
- Implementing the Super Emitter program under Best Practice 21. This utilized the Picarro mobile leak quantification technology to detect Grade 3 Super Emitters.[1] In 2018, PG&E repaired 128 Super Emitters.
- In 2018, PG&E repaired 2,017 distribution below ground Grade 3 leaks.
- For non-emergency gas transmission pipeline blowdowns, PG&E abated approximately 80 percent of the total gas volume released from its transmission pipeline projects through drafting and cross compression.

[1] Super Emitters are Grade 3 leaks that emit more than 10 standard cubic feet per hour (scfh).

By 2025, PG&E anticipates exceeding the 20 percent reduction goal through the following activities:

1. Begin a transition from the three-year gas distribution leak survey cycle to risk-based leak surveys. PG&E will utilize data analytics and risk modeling to prioritize the plats to be surveyed in order to optimize the number of leaks found, minimize the amount of time leaks stay open, and reduce emission.
2. Continue to use Picarro mobile leak quantification technology to identify Grade 3 Super Emitters (leaks larger than 10 standard cubic feet per hour (scfh)) and repair about 100 Super Emitters per year as proposed in PG&E's 2020 General Rate Case (GRC).
3. In PG&E's 2020 GRC, PG&E proposed a place-holder forecast for a limited number of below ground Grade 3 leak repairs of approximately 2,000 leaks per year. PG&E recommends performing below ground Grade 3 leak repairs at this pace going forward. However, PG&E's ultimate obligation may be lower or higher than this volume of repairs depending on the outcome of the Commission's reevaluation of Best Practice 21 based on the cost effectiveness data presented on this report (see Chapter 11).
4. Refining blowdown reduction strategies and begin to expand the use of these strategies at compressor stations and storage facilities.
5. Improve inventory of other devices that release gas to the atmosphere and evaluate cost effectiveness of device replacements.

There are current limitations on reaching the 40 percent reduction target by 2030 due to those emissions that are population-based (e.g. meter sets, pneumatic devices, etc.). However, if PG&E's proposed changes in population-based emission factors to direct measurements or calculations are approved by the CPUC, PG&E will reach the 40 percent reduction target by 2030 through the following activities:

1. Compressor station management. As part of Best Practice 17, Enhanced Methane Detection, PG&E will be utilizing various technologies to directly estimate the total emissions from its compressor stations. By moving to direct measurements, PG&E can focus on the large emitting components/equipment, develop and implement strategies to further reduce emissions from these facilities.

2. Measurement and Control (or Regulator) station management. One of the research and development (R&D) projects proposed in the 2020 Compliance Plan aims at developing a classification framework and methodology that will provide more accurate quantitative estimation of methane emissions at regulator stations. By moving to direct measurements, PG&E can focus on the large emitting components/equipment, develop and implement strategies to further reduce emissions from these facilities.

3. Meter set leak management. During the 2018 Compliance Plan period, PG&E piloted a program to take close-up photos of the above ground leak bubble sizes and recommend classifications based on bubble size. During the 2020 Compliance Plan period, PG&E plans to calculate emissions based on the bubble size classifications and representative

leak rate. Based on the emissions, PG&E can propose and implement repair timeframes by classification.

Table 1 compares the 2015 baseline emissions with the 2018 reported emissions, as reported in PG&E's 2018 Natural Gas Leak Abatement Annual Report, for each system category and the Best Practices that support emissions reduction for that system category. At this time, projections for 2019 Year End cannot be provided. The 2019 emissions will be submitted on June 15, 2020 in PG&E's Natural Gas Leak Abatement Annual Report. PG&E can provide updated comparisons after the publication of the 2019 emissions.

Table 1. 2015 Baseline vs. 2018 Reported Emissions Summary

System Categories	Emission Source Categories	Fugitive or Vented	2015 Baseline Emissions (Mscf)	2018 Total Annual Volume of Leaks & Emissions (Mscf)	Percentage Change for Year Over Year Comparison from 2015 to 2018	Best Practices Supporting Emissions Reduction
Transmission Pipelines	Pipeline Leaks	Fugitive	3,701	3,726	**0.7%**	BP 19 – Above Ground Leak Surveys BP 21 - Find It/Fix It BP 23 – Minimize Emissions from Operations, Maintenance and Other Activities
	All Damages	Fugitive	81,793	258	**(99.7%)**	
	Blowdowns	Vented	251,227	133,739	**(46.8%)**	
	Component Emissions	Vented	4,591	28,834	**528.1%**	
	Component Leaks	Fugitive	--	N/A	–	
	Odorizers	Vented	135	196	**45.3%**	
Transmission M&R Stations	Station Leaks & Emissions	Fugitive	579,240	574,180	**(0.9%)**	
	Blowdowns	Vented	65,456	25,476	**(61.1%)**	
Transmission Compressor Stations	Compressor Emissions	Vented	70,186	27,702	**(60.5%)**	
	Compressor Leaks	Fugitive	--	0	–	
	Blowdowns	Vented	19,864	50,075	**152.1%**	
	Component Emissions	Vented	--	18,852	–	

System Categories	Emission Source Categories	Fugitive or Vented	2015 Baseline Emissions (Mscf)	2018 Total Annual Volume of Leaks & Emissions (Mscf)	Percentage Change for Year Over Year Comparison from 2015 to 2018	Best Practices Supporting Emissions Reduction
	Component Leaks	Fugitive	15,823	10,549	**(33.3%)**	
	Storage Tank Leaks & Emissions	Vented	N/A	44	–	
Distribution Main & Service Pipelines	Pipeline Leaks	Fugitive	626,590	495,543	**(20.9%)**	BP 15 - Gas Distribution Leak Surveys BP 16 - Special Leak Surveys BP 21 - Find It/Fix It
	All Damages	Fugitive	146,335	28,079	**(80.8%)**	
	Blowdowns	Vented	141	202	**42.7%**	
	Component Emissions	Vented	N/A	N/A	**–**	
	Component Leaks	Fugitive	N/A	N/A	**–**	
Distribution M&R Stations	Station Leaks & Emissions	Fugitive	741,986	754,014	**1.6%**	
	All Damages	Fugitive	--	N/A	**–**	
	Blowdowns	Vented	147	207	**40.7%**	
Customer Meters	Meter Leaks	Fugitive	636,034	639,419	**0.5%**	
	All Damages	Fugitive	--	6,375	**–**	
	Vented Emissions	Vented	231	191	**(17.0%)**	
Underground Storage	Storage Leaks & Emissions	Fugitive	11,870	4,636	**(60.9%)**	BP 19 – Above Ground Leak Surveys BP 21 - Find It/Fix It BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Compressor Emissions	Vented	5,360	8,180	**52.6%**	
	Compressor Leaks	Fugitive	--	N/A	**–**	
	Blowdowns	Vented	16,324	10,402	**(36.3%)**	
	Component Emissions	Vented	--	81,125	**–**	
	Component Leaks	Fugitive	10,574	11,190	**5.8%**	
	Dehydrator Vent Emissions	Fugitive	6,761	14	**(99.8%)**	
Unusual Large Leaks	Transmission Pipeline		N/A	0		

System Categories	Emission Source Categories	Fugitive or Vented	2015 Baseline Emissions (Mscf)	2018 Total Annual Volume of Leaks & Emissions (Mscf)	Percentage Change for Year Over Year Comparison from 2015 to 2018	Best Practices Supporting Emissions Reduction
	Unexpected Releases					
		Total	**3,294,368**	**2,913,208**	**(11.6%)**	

Table 2 portrays estimated emission levels by Measure (some measures do not result in calculable emissions) in 2021, 2025 and 2030. The last column lists Cost Effectiveness from Part 5b which is discussed in greater detail in each Chapter. PG&E continues to refine areas for estimation and quantifying emissions. At this time, it is too early to provide a cost benefit in dollars for every measure.

Table 2. Emissions Level Estimate, MSCF, Year End

Measure (Chapter No.)	2021	2025	2025 % Reduc.	2030	2030 % Reduc.	Cost Effectiveness Part 5b $/MSCF
1) Non-Emergency Gas Transmission Blowdown Reduction (Chapter 3)	150,000	150,000	5%	250,000	6%	$25/mscf
2) Find It /Fix It (Chapter 11)	230,000	280,000	9%	330,000	10%	$8/mscf for Super Emitter repair $197/mscf for below ground Grade 3 leak repair
3) High-Bleed Pneumatic Device Replacement (Chapter 13)	20,000	25,000	1%	25,000	1%	N/A[2]
4) R&D Projects: Meter set leak management (Chapter 15)	150,000	150,000	5%	250,000	8%	TBD[3]
5) R&D Projects: Regulator station leak management (Chapter 15)	N/A	300,000	9%	400,000	12%	
6) Other Reductions			1%		3%	
TOTALS	**17%**		**30%**		**40%**	

[2] High-bleed pneumatic devices will either be replaced with low or no-bleed devices or removed completely depending upon final design of the station rebuild. Costs to replace/remove these devices are incorporated as part of the station rebuilds; therefore, the cost effectiveness cannot be accurately calculated.
[3] In the 2020 Compliance Plan, R&D will continue to work on quantifying emissions from meter set assemblies and regulator stations that enables PG&E to move from population-based emissions estimates to direct emissions calculations. This also enables PG&E to determine appropriate repair times for meter set leaks based on the meter set leak grade and actions needed to further reduce emissions at its regulator stations (e.g. component replacement, leak repair, etc.). PG&E anticipates developing detailed management plans for meter sets and regulator stations for its 2022 Leak Abatement Compliance Plan.

Each Chapter in this Compliance Plan describes a proposed Measure that consists of a Best Practice or a combination of Best Practices. The following is a table of concordance for Best Practices.

Table 3. Table of Concordance

BP #	Chapters Addressing this 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, Above Ground Leak Survey
20a	Chapter 10, Quantification and Geographic Tracking Chapter 15, R&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, R&D Projects
24	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 Practice. Some Best Practices may be addressed by more than one Measure. Per guidance from the CPUC/SED, each Chapter will detail the following information.

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 2018 estimated reduction? What further reductions are expected?
    2. In terms of the utilities' own 2018 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 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.

<u>Average Annual Revenue Requirement</u>

Revenue requirement represents how the cost to the utility is passed on to ratepayers, 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 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, include the cost benefit of the proposed measure, by determining the ratio of net cost to all reasonably quantifiable benefits, where net cost is the average annual revenue requirement developed in Part 4.

Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when estimates have been determined. Do any incremental costs, if known, or benefits overlap with other measures? If so, describe.

a) Determine cost effectiveness as the ratio of net cost to volume of methane reduced, dollars per MSCF. Use the average annual revenue requirement from Part 4 divided by average annual emission reduction for as many time periods as represented by the average annual revenue requirement.

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

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

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.

CHAPTER 1: COMPLIANCE PLAN

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E submitted its 2018 Compliance Plan as an attachment to its 2018 Gas Safety Plan on March 15, 2018. PG&E amended its plan on November 8, 2018, based on CPUC's feedback. The 2018 Compliance Plan summarized the actions taken in the 2018 Compliance Plan period (i.e. 2018 and 2019) 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).

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 TBD 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

No reductions in emissions are directly associated with this measure. This measure is specific to creating a process and not related to activities that reduce emissions.

Part 2. Proposed New or Continuing Measure

The chapters that follow address PG&E's plans to comply with the 26 Best Practices adopted in the Final Decision for the 2020 Compliance Plan period (i.e. 2020 and 2021). PG&E tracks completion of compliance plans into its internal tracking system to enable filing on a biennial basis. This 2020 Compliance Plan is submitted as a separate attachment to the 2020 Gas Safety Plan. In addition, a management review of this plan is performed prior to submission. The details of implementing each best practice can be found the subsequent chapters.

Part 3. Abatement Estimates

No reductions in emissions are associated with this measure. 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

Cost effectiveness/benefits will be discussed at the measure level, where applicable.

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 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 November 15, 2019, PG&E updated its existing Climate Change Policy (ENV-03) to include a specific reference to minimizing methane, a potent greenhouse gas, and SB 1371 and SB 1383.

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 TBD 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. PG&E updated its existing Climate Change Policy to put focus on methane emissions, consistent with the best practice requirement. No reductions in emissions are associated with this measure. This measure is specific to creating a process and not related to activities that reduce emissions

Part 2. Proposed New or Continuing Measure

No additional changes will be needed for the 2020 Compliance Plan period.

Part 3. Abatement Estimates

Not applicable as this measure updates an existing Company policy with the required language in compliance with Best Practice 2.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Compliance with Best Practice 2 is complete, and no additional action is anticipated for the 2020 Compliance Plan period. Therefore, no additional funding is required.

Part 5. Cost Effectiveness/Benefits

This measure is the implementation of a Company-wide policy; therefore, emissions reduction cannot be calculated based on this measure.

CHAPTER 3: NON-EMERGENCY GAS TRANSMISSION BLOWDOWN REDUCTION

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

- Schedule all planned gas transmission system construction projects with sufficient lead time to incorporate emission reduction strategies, including: project bundling, drafting, cross compressing and flaring;
- Reduce pressures of transmission isolation areas to lowest operationally feasible levels to minimize the venting of methane;
- Document significant factors considered in methane abatement decisions for all planned transmission projects;
- Measure all transmission blowdown and reduction amounts for all scheduled projects;
- Accelerate leak detection and repairs where feasible and employ methane reduction strategies in making associated transmission system repairs.
- Complete a post-blowdown evaluation and analysis after blowdown events with a chamber volume exceeding 50 cubic feet (cf), which is consistent with EPA's 40 CFR Part 98 greenhouse gas (GHG) reporting requirements.

The post-blowdown evaluation includes the following information: 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 higher than the planned ending pressure, the reason for the variance. PG&E may choose to modify what type of information is collected for the post-blowdown evaluation as this process is further developed.

PG&E rolled out training to transmission Gas Operations employees in Q4 of 2019 to provide awareness of the following:

- PG&E's commitments to reduce methane emissions as much as feasible during non-emergency gas transmission blowdowns;
- Roles and responsibilities outlined in the new TD-5601 guidance documents; and
- The goals and requirements of new GHG Feasibility Assessment.

In-person training was provided to all transmission project managers and project engineers as they both have critical roles in evaluating the feasibility of incorporating methane emission reduction strategies into project that require gas blowdowns.

a) Best Practice(s) Addressed by this Chapter

Best Practice 3 – Pressure Reduction 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 TBD. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

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 TBD. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

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. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

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. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

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. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

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

In 2018, PG&E abated 80 percent of the total gas volume from transmission pipeline and regulator station projects (see Table 3 below).

Table 3. 2018 Transmission Pipeline and Regulator Station Abatement Activities

Pipeline Activity Type	Total Gas Volume (Mscf)
Drafting	119,837
Cross Compression	504,320
Blowdown	159,215
Total Gas Baseline	*783,372*
Percent Gas Diverted to Drafting or Cross Compression	*80%*

Part 2. Proposed New or Continuing Measure

The Greenhouse Gas Emissions Reduction Standard and associated Procedure meet the intent of Best Practices 3 through 7. PG&E will continue to utilize these documents in the 2020 Compliance Plan period and updates may be made pending results of post-blowdown evaluations that are conducted.

To further support Best Practice 23, in 2020 and 2021, PG&E plans to pursue the following to further reduce methane emissions from planned transmission blowdowns:

1. Improve the data collection for post-blowdown evaluations by implementing an enhancement to the current clearance process in SAP that will allow for electronic data collection real-time during clearance execution. Better data quality and faster collection will support PG&E's efforts to identify procedural enhancements for further methane emission abatement opportunities. PG&E aims to implement and provide training for this IT enhancement by the end of 2020.

2. Throughout 2020 and 2021, PG&E plans to review post-blowdown evaluation data on an on-going basis to identify opportunities further reduce methane emissions from planned transmission blowdowns. This effort will likely require the implementation of process improvements and revisions to the TD-5601 standard and procedure documents.

3. PG&E also plans to apply lessons learned from transmission pipeline blowdowns to evaluate the feasibility of developing a process and new procedure to ensure methane emissions are reduced as much as feasible from facility blowdowns prior to the end of 2021. PG&E will explore available technology and determine which solutions to implement. These solutions will likely require the purchase of additional equipment or contract support as well as changes to existing operations.

4. Cross-compression program goals for 2020-2021:
   a) Investigate the purchasing of a gas-driven mobile fill compressor and tube trailers in 2020, which would allow PG&E to use mobile compression to target reduction of methane emissions from smaller blowdowns or pipelines that do not have a nearby pipeline to cross compress into.
   b) Explore the applicability and feasibility of using multi-stage/boost compressors to further reduce the amount of gas released during backbone pipeline blowdowns. Multi-stage/boost compressors have a bigger pressure differential which would allow compression to much lower levels than the current reciprocating compressors.
   c) In 2020, PG&E plans to purchase two more support trailers which will allow PG&E to support three different cross compression jobs simultaneously, furthering PG&E's ability to reduce methane emissions while preforming critical safety and infrastructure work on transmission pipelines.

5. PG&E is currently unable to quantify the amount of natural gas abated from bundled pipeline clearances. In 2020, PG&E plans to complete a review of 2018 and 2019 bundled clearance blowdown data to develop an average multiplier that can be used to estimate natural gas savings from bundled projects moving forward. In 2021, PG&E will make enhancements to the overall bundling and integrated investment plan processes to incorporate information learned from the completed bundling analysis.

6. Evaluate the use of Zero Emission Vacuum and Compressor (ZEVAC) technology on in-line inspection (ILI) projects and determine if this technology should be expanded to further reduce methane emissions from planned transmission blowdowns. If it is determined that this technology is a good solution to reduce methane emissions from ILI projects, PG&E will incorporate this technology into existing processes and procedures. This would require purchase of additional equipment or contract support as well as changes to existing operations. See Chapter 15 R&D Projects.

7. Pilot new technology to oxidize methane to replace flaring on one project and determine if this technology should be expanded to further reduce methane emissions from planned transmission blowdowns. This would require purchase of additional equipment or contract support as well as changes to existing operations. See Chapter 15 R&D Projects.

8. Assess the efficiency of flaring in terms of unburned methane. See Chapter 15 R&D Projects.

The Greenhouse Gas Mandatory Reporting Requirements (GHG MRR), specifically 40 CFR 98.232(m) and 40 CFR 98.233(i), currently requires reporting of transmission blowdown amounts from vessels equal to or greater than 50 cubic feet. This measure requires greater focus on emission reduction strategy, which is beyond the GHG MRR regulation.

As stated above, the following technologies are proposed to further reduce emissions from non-emergency blowdowns:

a) SAP enhancements to provide for real-time work clearance data collection to facilitate timely post-blowdown evaluations;
b) ZEVAC technology on ILI projects to determine if this can be used to further reduce emissions from planned transmission pipeline blowdowns; and
c) New technology developed by NYSEARCH and Stanford to catalytically oxidize methane at lower temperatures as an alternative to flaring.

Part 3. Abatement Estimates

Abatement feasibility and effectiveness highly depends on the nature of the work and the type of assets. Typically, maintenance work, such as valve replacement and hydrotest, has a larger potential for emissions compared to inline inspections that requires only limited blowdown. Large backbone transmission pipelines present better abatement potential than local transmission pipelines because of their larger volume and pressure. The portfolio of work varies from year to year in term of assets and nature of the work.

PG&E is targeting an annual abatement of 80 percent of potential gas releases from backbone pipeline clearances and 50 percent of potential gas releases from local transmission pipeline clearances. In addition, PG&E expects to expand its methane emission reduction program in 2020-2021 to include transmission station blowdowns, which should further increase overall annual gas abatement.

Part 4. Cost Estimates and Average Annual Revenue Requirement

The proposed actions for this measure during the 2020 Compliance Plan period are forecasted through PG&E's rate cases and no additional funding is being requested.

Actions 1 through 5, outlined in Part 2 above, are considered support work and the costs are embedded in the adopted forecast of PG&E's Operational Management and Operational Support section of PG&E's 2019 Gas Transmission & Storage rate case.

Costs associated with Actions 6 through 8 are discussed in Chapter 15 R&D Projects.

Part 5. Cost Effectiveness/Benefits

Project managers were provided a guidance of $25/mscf of gas saved to determine which GHG reduction strategies would be cost effective. This guidance was based on EDF's social cost of methane of $1,100 per ton, which is equivalent to approximately $22/mscf. Adding in the cost benefit of the avoided Cap & Trade costs, which amounts to approximately $3/mscf, the estimated total of $25/mscf is used as a guideline. If the strategy/strategies resulted in less than or equal to $25/mscf of gas saved, then that strategy or strategies would be implemented as part of the project.

CHAPTER 4: EMERGENCY PROCEDURES

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E performs regular maintenance on its system and has procedures in place to minimize and support the prevention of uncontrolled release of methane. In addition, PG&E's Gas Emergency Response Plan (GERP) addresses how the company responds to emergencies, including uncontrolled release of gas from the gas system or storage facility. Although PG&E relies on multiple layers of protection to prevent the uncontrolled release of natural gas, when releases do occur, PG&E is prepared to respond. PG&E reviews and updates the GERP on an annual basis.

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. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

b) Effectiveness

Cost effectiveness was not calculated in the 2018 Compliance Plan. Emissions reduction are directly associated with the length of time a leak remains open. Any improvement in the average gas shut in time will directly impact the emissions reduction by reducing the amount of time the leak stays open.

Part 2. Proposed New or Continuing Measure

PG&E will continue to utilize its GERP to comply with the Best Practice. No additional actions will be taken.

Part 3. Abatement Estimates

Emissions reductions cannot be directly measured through implementation of its 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 will be required for the 2020 Compliance Plan period.

Part 5. Cost Effectiveness/Benefits

This measure is the review and update of PG&E’s emergency procedures; therefore, emissions reduction cannot be calculated based on this measure. 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 Records Information Management Standard. This Standard establishes requirements for records and information, roles, and responsibilities for managing and governing records and information at PG&E Corporation and its subsidiaries, including Pacific Gas and Electric Company (together, PG&E). The Standard applies to records and information created, modified, maintained, stored/archived, retrieved, transmitted and disposed 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 REG0210 Regulatory – CPUC Permanent. 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. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

b) Effectiveness

This measure addresses recordkeeping, which does not directly reduce emissions. Therefore, there are no emission reductions associated with recordkeeping requirements.

Part 2. Proposed New or Continuing Measure

Compliance with Best Practice 9 has been fulfilled, therefore, no additional actions are required for the 2020 Compliance Plan period.

Part 3. Abatement Estimates

No reductions in emissions are associated with this measure. 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

This measure relates to recordkeeping; therefore, emissions reduction cannot be calculated based on this measure.

CHAPTER 6: GAS TRAINING

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E currently utilizes a talent requisition site to provide guidance on hiring both union and non-union employees. This allows for 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 will be required to take the requisite trainings 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 Program focuses on developing an up to date curriculum that reflects current procedures and regulations, properly introducing and reinforcing safety requirements.

The drivers for curriculum development include:

- Regulatory requirement-driven updates to work procedures;
- Facilitating knowledge transfer from employees exiting the workforce to those entering;
- Emergent technologies and processes; and
- Changes to work procedures.

The scope of the curriculum developed is informed by business needs. Curriculum development priorities are set through the Gas Training Governance (GTG)[4] 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 courses, among others, support PG&E's efforts to reduce greenhouse gas emissions and these best practices:

Greenhouse Gas Emission Reduction – Gas Transmission Blowdowns

PG&E developed a new process to reduce GHG emissions from planned transmission pipeline blowdowns to satisfy commitments detailed in PG&E's 2018 Compliance Plan. This process utilizes an online GHG Feasibility Assessment tool and includes training on how to use this tool

[4] The GTG is a cross-functional team of gas operations personnel from the International Brotherhood of Electrical Workers and management across several departments that hear business cases brought forth by organizations that are requesting the development of new gas curriculum at PG&E Academy. This team evaluates requests to develop new curriculum. The team's primary function is to use their knowledge and experience to determine: if the business case is well considered, the submitter has a way to measure the planned improvement in business objectives, that the request is in alignment with Gas Operations priorities (risk, initiatives, etc.), and that the stakeholder (student) analysis is complete.

during project planning. This tool displays process flows which requires that project teams consider the use of methane abatement strategies when planning their work, implement them when feasible, build time into their project schedules, estimate the amount of GHG emissions to-be abated, and complete a post-blowdown evaluation and analysis to determine if further revisions to this process are necessary.

Leak Survey DP-IR Tool

This course is designed to equip the operator with the knowledge and skills to safely and effectively test, operate, and maintain a Heath Detecto Pak-Infrared (DP-IR) leak detection device. The training includes explanation of the DP-IR instrument components and functions, as well as procedures for preparing and maintaining the DP-IR and using the DP-IR to detect gas leaks.

Leak Survey Detection & Grading

Leak survey detection and grading 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.

Leak Investigation

The goal of this course is to train PG&E employees to follow a systematic approach for investigating and pinpointing gas leaks in accordance with work procedure TD-4110P-09 Leak Grading and Response.

After completing this course, the employee should be able to:

- Prepare resources and tools used to investigate a natural gas leak.
- Anticipate how natural gas will migrate, based on given environmental characteristics and facilities.
- Read the street to identify potential source of reported leak and impacts of excavation.
- Determine the location, number, depth, and size of bar holes based on site evaluation and information provided.
- Identify the N-S-E-W perimeter of the leak investigation area.
- Assess the excavation to identify the correct location to repair or isolate a leak.
- Grade leaks per established procedures.

Gas Emergency Response Plan (GERP) Training

PG&E's Gas Emergency Preparedness training consists of three GERP courses as follows:

- Gas-9121 GERP Awareness;
- Gas-9122 GERP Response Training; and
- Gas-9123 GERP Emergency Center (Instructor Led Training).

These trainings 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 a learning center and utility village. The Learning Center is the primary technical training center that includes classrooms, labs, M&C tech center (e.g. the Indoor Flow Lab wherein compressed air is used to simulate natural gas flow), and a gas service representative (GSR) area, where GSRs will be trained in customer service 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.

The Gas Safety Academy utilizes compressed air in the Gas Pipeline Operations & Maintenance (GPOM) flow lab, gas Chromatograph room, as well as the Field Services lab for service mechanic training. Utilization of compressed air versus natural gas provides a zero-gas emission training environment and allows our students to safely and quickly perform routine maintenance on simulated distribution and transmission regulation equipment. In addition, allowing our student population to train and perform rotary meter operations such as differential testing, flange and gasket installation/removal, in addition to complete meter removals, allow for comprehensive training without the need to exhaust natural gas to atmosphere.

Regarding operations and maintenance of multiple distribution and transmission regulation stations and associated gas measurement equipment (ERX, SCADA, Total-Flow, Becker controllers, etc.), students and lab operators are able to remove components on the gas system and allow students to perform inspections normally performed in the field without the need to exhaust natural gas to atmosphere.

An additional benefit of utilizing the flow lab is that we can install new technology or gas regulation component that requires testing and "proof of concept" operation prior to introducing the product in the field with unlimited attempts to fill/evacuate the pipeline with compressed air versus natural gas. The quantity of natural gas emissions avoided by utilization of compressed air is almost incalculable.

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 (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 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 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

There were no emissions reductions anticipated from Gas Operations Training that support the best practices mentioned above. Therefore, cost effectiveness is not applicable.

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 being proposed for the 2020 Compliance Plan period.

PG&E will utilize its historic work as described above in Part 1 to address any new classifications that are required. Current job classifications adequately address necessary skills and training for employees whose work can affect methane emissions and leak abatement. At this time, PG&E does not anticipate any new classifications to be created for methane emissions minimization or leak abatement in 2020 and 2021. Therefore, compliance with Best Practice 14 is complete.

Part 3. Abatement Estimates

Emissions reductions cannot be measured from training classes.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Gas Training does not directly contribute to emissions reduction. Annual revenue requirements for all planned gas training (including those listed above) were forecasted in PG&E's 2020 GRC[5]. For 2020, PG&E forecasted $4.796 million towards developing and providing gas training to its employees. There is no incremental funding is required to comply with these Best Practices.

Part 5. Cost Effectiveness/Benefits

This measure is the is the implementation of training and programs through Gas Operations Training; therefore, emissions reductions cannot be calculated based on this measure.

[5] See PG&E's 2020 General Rate Case, Exhibit (PG&E-3) Chapter 11.

CHAPTER 7: GAS DISTRIBUTION LEAK SURVEYS

Part 1. Evaluate the Current Practices Addressed in this Chapter

As of January 1, 2018, PG&E's gas distribution leak surveys moved from a four-year to a three-year leak survey cycle in order to comply with this best practice. PG&E performs its gas distribution leak surveys using the Picarro Surveyor along with traditional foot surveys.[6] In Q2 2018, PG&E deployed the "Inspect" application to the leak surveyors systemwide. The application is used to document leaks and abnormal operating conditions through a mobile device.

In Q2 2019, PG&E began a pilot to perform additional leak surveys on select vintage pipes on distribution assets. The material focus of the special leak survey is pre-1940 steel and pre-1975 Aldyl-A vintages. The surveys only target pipe segments of this vintage with a leak history. PG&E has incorporated the vintage pipe leak survey into the Distribution Integrity Management Program (DIMP) leak surveys and funding has been included in its 2020 GRC.[7]

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.

b) Effectiveness

Emissions reductions as a result of moving from a four-year to a three-year leak survey cycle cannot be fully realized until Year 4 of the new cycle after steady state has been reached. In

[6] PG&E's 2020 General Rate Case, Exhibit (PGE-3), Chapter 8, pages 8-13 to 8-14.
[7] The 2020 forecast for the DIMP Leak Survey Program is $0.7 million and is based on 54,500 services.

other words, the three-year leak survey cycle enables PG&E to detect and fix more leaks than in the previous four-year leak survey cycle. Therefore, PG&E anticipates a decrease in emissions in subsequent leak survey cycles.

Part 2. Proposed New or Continuing Measure

PG&E proposes to begin the process to replace accelerated three-year leak surveys with risk-based leak surveys and continue to evaluate the feasibility and benefits associated with conducting risk-based leak surveys. In collaboration with Picarro, Inc., PG&E developed a methodology to combine observed leak rate data from previous surveys, risk score analysis, methane indications from higher frequency mobile monitoring, and predictive analytics to optimize leak surveys. Plat maps will be ranked based on their probability of having leaks at a certain time. Leak surveys will be prioritized for higher risk plat maps, with the backstop of five years to maintain compliance requirements. From this method, it is anticipated risk will be reduced by maximizing leak detection. This method coupled with Super Emitter early detection and repair will leverage mobile data collection and focus leak investigations on areas with higher leak probabilities.

Gas distribution leak surveys are required under 49 CFR 192 and GO 112-F. Accelerated three-year leak surveys are incremental to the five-year surveys mandated in 49 Code of Federal Regulations (CFR) 192, Subpart M and GO 112-F, Subpart C regulations. Risk based leak surveys are incremental to the five-year mandated surveys as well. PG&E plans to progressively deploy risk-based leak surveys in 2020.

This measure overlaps with best practices 9, 16, and 17, as these best practices also relate to leak survey scheduling. There will be coordination required to maintain records and to schedule the various surveys happening on different frequencies.

Part 3. Abatement Estimates

Three-year leak surveys enable leak repairs to be conducted at a faster rate than the mandated five-year leak survey cycles. Transitioning to risk-based leak surveys optimizes leak surveys so that leaks in higher risk areas are detected faster and can be repaired at faster rate. Emissions reductions from gas distribution leak surveys as proposed in this measure are addressed in Chapter 11, Find It/Fix It.

Part 4. Cost Estimates and Average Annual Revenue Requirement

The Gas Distribution three-year leak survey cycle with the use of Picarro has been forecasted in the 2020 GRC and is summarized as follows:

1. Traditional Leak Survey: PG&E forecasts surveying 543,301 services and associated main in 2020, resulting in a forecast cost of $7.7 million in 2020.
2. Picarro Leak Survey: PG&E anticipates surveying 663,997 services and associated main in 2020 for a forecast cost of $6.1 million in 2020.

Beginning to transition to the risk-based leak survey will not require incremental funding. Surveys will be optimized to focus on high risk plat maps with a backstop of five years to maintain compliance requirements.

Part 5. Cost Effectiveness/Benefits

The forecasted costs in the 2020 GRC for leak survey will not change as a result of PG&E's transition to a risk-based leak survey. The anticipated benefits of transitioning to a risk-based leak survey is that PG&E will be able to prioritize leak surveys to those plats with higher leaks sooner than the traditional five-year leak survey cycle required by regulations, which in turn prioritizes the leak repair in those areas depending upon leak grade. As a result, a greater methane reduction is anticipated. Cost effectiveness/benefits from leak repairs as a result of this measure is addressed in Chapter 11 – Find It/Fix It.

CHAPTER 8: METHANE DETECTION

Part 1. Evaluate the Current Practices Addressed in this Chapter

During the 2018 Compliance Plan period, PG&E continued to use advanced mobile and aerial technologies and engaged additional R&D efforts to improve these technologies. PG&E continued the use of highly sensitive mobile methane and ethane detection technology (Picarro Surveyor), and developed new solutions through R&D efforts, including:

- Piloting fixed wing DIAL (Differential Absorption LiDAR) aerial surveys;
- Developing and Testing light unmanned aerial vehicle (UAV) mounted leak detection technologies;
- Exploring Optical Imaging Technologies; and
- Piloting the use of high sensitivity handheld devices for leak surveys.

The CARB Oil and Gas Rule directs compressors and storage facilities operators to perform quarterly leak surveys, to repair leaks quickly after discovery, and to install stationary ambient detectors at storage facilities. To comply with this regulation, PG&E continued utilizing testing stationary leak detectors at a small number of facilities to evaluate performance and cost factors of different units before broadly deploying units across its territory. Stationary methane detectors include point detectors with sensitivity varying from part per billion to percent gas, Optical Gas Imaging Systems (OGI) and Open Path methane detectors. In addition, PG&E continued to work with the industry to lower cost of sensors. For instance, PG&E supported a project with Operations Technology Development (OTD) to evaluate commercially available methane sensors for leak survey and continuous monitoring applications.

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 above ground 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 more leaks than the traditional leak survey tools. By allowing the faster detection of more and smaller leaks from the gas system, this measure leads to methane emission reductions that can be represented by the adjustment of leak-based emissions factors for the utilities implementing this measure. Field measurements will be performed to support the new emissions factors and calculate the abatement. Therefore, cost effectiveness in reducing emissions was not calculated.

Part 2. Proposed New or Continuing Measure

PG&E will continue to implement the current actions related to enhanced methane detection as provided in the 2018 Compliance Plan to comply with Best Practice 15. This action uses and explores a broad range of technologies. Current work leverages Cavity Ring Down Spectroscopy (CRDS) high sensitivity for mobile survey and DIAL for airborne surveys. R&D and pilot activities will explore additional technologies.

Regarding stationary methane detection, PG&E will continue to utilize stationary methane detectors. The following provides the remaining milestones for stationary methane detectors at regulator stations.

> Q2 2020: Tests of technologies and assessment of emissions of regulator stations. Technologies tested will be evaluated for leak monitoring application at storage facilities or compressor stations to comply with CARB's Oil and Gas Rule.
>
> Q4 2020: Define measurement protocol to establish emissions factors for regulator stations. Definition of new emission factors for regulation stations based on leak and controller types
>
> Q1 2021: Determination of stationary sensor deployment effectiveness

Part 3. Abatement Estimates

By allowing faster detection of a higher number of smaller leaks from the gas system, this measure leads to methane emission reductions that can be represented by the adjustment of leak-based emissions factors for the utilities implementing this measure. Field measurements will be performed to support the new emissions factors and calculate the abatement.

Part 4. Cost Estimates and Average Annual Revenue Requirement

The actions contained in this measure are funded through PG&E’s R&D funding mechanisms and in some cases, funding is cost-shared by other utilities through research consortium. In PG&E’s 2020 GRC, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects. No incremental funding is required to continue implementation of this measure.

Part 5. Cost Effectiveness/Benefits

PG&E is using new technology to implement this best practice. PG&E expects the new technologies to provide benefits that evolve over time; however, at this stage of development, PG&E cannot quantify any cost-effectiveness or cost benefits related to the new technology PG&E notes that the average leverage ratio for the projects is higher than five, which means

PG&E is paying approximately one-fifth of the research costs. This allows PG&E to keep R&D activities cost-effective.

CHAPTER 9: ABOVE GROUND LEAK SURVEY

Part 1. Evaluate the Current Practices Addressed in this Chapter

At PG&E's compressor stations, gas storage facilities, city gates and regulator stations, PG&E performs foot patrol to identify leaks, grades the identified leaks, and either rechecks or repairs the leaks based on compliance dates. Leak surveys are completed on a quarterly basis in compliance with the CARB Oil and Gas Rule. Other compliance surveys are completed on a semi-annual basis, in addition to audio and visual surveys performed on equipment daily, as required by GO 112-F. In 2019, PG&E began utilizing the Inspect App for recording leak surveys to effectively track data related to above ground and below ground leaks. Inspect communicates directly with SAP, which is the system of record for assets, increasing efficiency and effectiveness. Leaks are entered in Inspect and potential repairs are identified within 30 - 45 seconds.

a) Best Practice(s) Addressed by this Chapter

Best Practice 19 – Above Ground Leak Surveys: Utilities shall conduct frequent leak surveys and data collection at above ground 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 above ground and pressures above 300 psig only). At a minimum, above ground leak surveys and data collection must be conducted on an annual basis for compressor stations and gas storage facilities.

b) Effectiveness

The mandatory semi-annual and quarterly leak surveys enabled PG&E to detect and repair leaks at a faster rate. As shown in Table 1 in the Introduction, PG&E reported a decrease in fugitive emissions (between 2015 and 2018) associated with leaks at its compressor stations, regulator stations, and underground storage facilities.

Part 2. Proposed New or Continuing Measure

PG&E will continue its existing above ground leak survey process as required by regulations. No additional actions are proposed to comply with this Best Practice. During the 2020 Compliance Plan period, PG&E will be evaluating technologies that will be able to quantify emissions from compressor stations and its regulator station (see Chapter 15 R&D Projects)

In parallel, PG&E will explore new and advanced technologies to detect above ground leaks including gas imaging camera, low-cost point sensors, and drone-based leak quantification technology through R&D projects

Part 3. Abatement Estimates

Not applicable as this measure relates to detecting leaks. Due to increased leak survey frequencies, this enables PG&E to detect, grade, and fix leaks at a faster pace.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Semi-annual compliance leak surveys of PG&E's transmission system mandated in GO 112-F were forecasted in PG&E's 2019 Gas Transmission & Storage (GT&S) Rate Case. The adopted forecasts for the 2020 Compliance Plan period for are shown below and includes transmission pipeline leak surveys.

Description (MAT code)	**2020**	**2021**
Ground leak survey (JOE)	$1.306 million	$1.344 million
Leak Recheck (JOR)	$0.130 million	$0.134 million
Total	**$1.436 million**	**$1.478 million**

Due to timing of the effective date of the CARB Oil and Gas Rule, the quarterly leak surveys were not forecasted in the 2019 GT&S Rate Case. Funding of the quarterly leak surveys compliance requirements were for 2020 was approved on November 19, 2019 through PG&E's Quarterly Business Review. PG&E approved forecast for the quarterly leak surveys was $3.3 million in 2020.

No incremental funding is being requested as part of this Compliance Plan.

Part 5. Cost Effectiveness/Benefits

Above ground leak surveys at compressor stations and regulator stations required under 49 CFR 192, GO 112-F and CARB's Oil and Gas Rule. Repairs from these above ground leak surveys are mandated in GO 112-F, Section 143.2. Since this measure leverages the mandated leak survey and repair in order to comply with Best Practice 19 and there are no incremental actions is proposed, a cost effectiveness/benefit analysis will not be provided for abatement purposes.

CHAPTER 10: QUANTIFICATION AND GEOGRAPHIC TRACKING

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E began exploring leak quantification through a NYSEARCH project in 2014. The results of this project have shown the uncertainty of mobile survey when measuring flow rate of leaks on the distribution system. These results were used in establishing the Super Emitter Program described in Chapter 11, Find It/Fix It, in support of Best Practice 21.

In addition, PG&E and NYSEARCH have collaborated with the Pipeline and Hazardous Material Safety Administration (PHMSA) to establish a method to validate results found by leak quantification systems.

In parallel, PG&E has initiated other R&D projects with OTD and NYSEARCH to improve and develop new techniques for leak quantification.

Lastly, PG&E developed a centralized, searchable map that shares gas-related emissions data collected over the last three years through its robust system-wide gas emissions survey process. The data is tracked and measured to ensure that PG&E can track service-area wide decline in year-over-year gas-related emissions.

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 ARB 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 ARB 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 of and geographically tracking leaks and not related to activities that reduce emissions.

Part 2. Proposed New or Continuing Measure

PG&E proposes to continue the R&D projects and use the results to refine emission factors and establish emission factors specific to the utility.

Currently, PG&E is collaborating with Picarro, Inc. to improve the emission measurement performance of the system and Super Emitter program. This includes software improvements, dashboard development for quality control, and quality control of mobile leak surveys, and explore the development of validation protocol across technologies.

In parallel, PG&E has initiated other R&D projects with OTD and NYSEARCH to improve and develop new techniques for leak quantification. The technologies are being developed through R&D. The final technology and procedures implemented will depend upon those results.

Finally, as stated in Part 1 above, PG&E currently can geographically track and evaluate leaks and transfer leak data to a central database in order to provide data for leak maps. PG&E will publish a publicly available geographic map that displays emission information by zip code. PG&E plans to update the data as after annual emission reporting is completed. The public interface is currently undergoing customer usability testing and will be live by end of the first quarter of 2020.

Part 3. Abatement Estimates

Calculating abatement is not applicable as this measure aims to quantify and geographically track leaks.

Part 4. Cost Estimates and Average Annual Revenue Requirement

The cost of the R&D projects in this measure have been forecasted in PG&E's 2020 GRC, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects. No incremental funding is currently required to complete forecasted work in the 2020 Compliance Plan period.

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 currently conducts compliance surveys on a portion of its system each year, and uses leak grades, a methodology which ranks leaks based on risk, for repair and monitoring. The Super Emitter survey, which is performed in addition to existing compliance surveys, prioritizes repairs based on methane concentrations. Two Picarro cars are used to complete both compliance and Super Emitter leak surveys. These vehicles cover the portion of the service territory not covered by PG&E's compliance survey. The data from both the supplemental survey and PG&E's compliance survey will be reviewed to prioritize leaks with flow rate greater than 10 scfh.

During the 2018 Compliance Plan period, PG&E accelerated its leak survey cycle from five-years to three-years. PG&E utilized the Picarro mobile leak quantification technology to identify Super Emitters in its leak backlog. PG&E continued to fix all Grade 1 and Grade 2 leaks, as required by regulations. In accordance with the Commission's GO 112-F, PG&E repairs all Grade 1 leaks immediately and Grade 2 leaks within 12 months, with a six-month recheck.

Repair of Grade 3 leaks during the 2018-2019 period was limited following the Commission's issuance of Resolution G-3538 in which the Commission expressed concern regarding the cost effectiveness of below ground Grade 3 leak repairs relative to the expected emission reduction and requested that PG&E reduce its expenditures on these leak repairs to half the requested ratepayer funding.

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

The following summarizes that leak repairs performed during the 2018 Compliance Plan period.

Grade 3 Leak Repair

The following table summarizes the 2018 Compliance Plan estimated versus actual leak repairs:

Table 5. 2018 Compliance Plan Estimated vs. Actual Leak Repairs

Leak Grade	2018 Planned Units	2018 Actual Units
Above ground Grade 3	19,484	23,335
Below ground Grade 3	1,391 (for 2018-2019)	2,017

Below ground Grade 3 leak repair exceeded the planned number of repairs because the Commission's directive in Resolution G-3538 to reduce spending on these leak repairs was issued late in 2018 when a higher rate of repairs had been planned and scheduled that could not be cancelled or withdrawn.

Based on its historic belowground Grade 3 leak attrition rate, PG&E assumed that 30 percent of its leak backlog will be resolved either because a leak was upgraded to a Grade 1 or Grade 2 leak and repaired pursuant to those timelines, or because the leak was eliminated for other reasons, as stated above. In 2018 and 2019, 509 below ground Grade 3 leaks were resolved through attrition.

The number of above ground and below ground Grade 3 leaks repaired in 2019 will be provided in PG&E's 2019 Natural Gas Leakage Report for the Leak Abatement OIR.

Super Emitter

In the 2018 Compliance Plan, the methane abatement resulting from the Super Emitter program for 2018 was estimated to be 119 million standard cubic feet (MMscf). In 2018, with the Super Emitter Program the emissions from distribution mains and services leaks totaled 113 MMscf. Without the Super Emitter Program, the total emissions would have totaled 143 MMscf.

The number of Super Emitters repaired in 2019 will be provided in PG&E's 2019 Natural Gas Leakage Report for the Leak Abatement OIR.

The following summarizes the effectiveness of the actions taken to comply with Best Practice 21 during the 2018 Compliance Plan period:

Grade 3 Backlog Reduction

On October 11, 2018, the Commission approved Resolution G-3538, "Forecast Requests for Utility Natural Gas Leak Abatement Program Memorandum and Balancing Accounts" (Resolution). The Resolution stated that PG&E's proposal to reduce its leak backlog of Grade 3 underground leaks is excessively costly relative to the expected emission reduction. Furthermore, it stated that given the excessive costs to repair the Grade 3 leak backlog in PG&E's service territory, PG&E's budget in this program would be limited to no more than half the requested ratepayer funding for its proposed Grade 3 leak backlog in the 2018-2019 period. PG&E had originally requested $21.2 million for below ground Grade 3 leak repair.[8] Pursuant to the Resolution, PG&E revised its estimate of below ground Grade 3 leak repairs for the 2018-2019 period to 1,391 based on 50 percent of the original forecast, or $10.6 million. As discussed above, however, given planned and scheduled work that was already in flight at the time the Resolution was issued, PG&E completed more below ground Grade 3 leaks than the revised 2018 Compliance Plan forecast of 1,391.

In the 2018 Compliance Plan, PG&E estimated that the average cost of repairing a below ground Grade 3 leak would be $7,622, including expense and capital cost for leaks on mains and services and overhead. In 2018, PG&E spent approximately $15.133 million, which includes expense and capital, to repair 2,017 below ground Grade 3 leak repairs. Based on this actual spend divided by the number of below ground Grade 3 leaks repaired, the actual average cost to repair this type of leak was approximately $7,502. PG&E estimates the total abatement of Grade

[8] PG&E's Advice Letter 3902-G-A

3 leak repairs to be approximately 38 mscf per leak[9]. Therefore, in 2018, the total abatement of below ground Grade 3 leaks repaired was 76,646 mscf. As a result, dividing the total spend in 2018 by the 2018 emissions abated, the cost per Mscf was approximately $197/Mscf for below ground Grade 3 leak repairs.

Super Emitter Program

In the 2018 Compliance Plan, PG&E estimated that cost effectiveness of the Super Emitter program was approximately $22/Mscf. [10] In 2018, PG&E spent $0.755 million on the Super Emitter repairs. PG&E estimates the abatement from Super Emitter leak repairs to be approximately 707 mscf per leak[11]. PG&E estimated a total abatement of 90,382 Mscf from repairing 128 Super Emitter leaks. As a result, dividing the total spend in 2018 by the 2018 emissions abated, the cost per Mscf was approximately $8/Mscf for the Super Emitter repairs.

Part 2. Proposed New or Continuing Measure

PG&E will continue to perform accelerated leak surveys on an annual basis using Picarro mobile leak quantification technology to identify the Super Emitters in its leak backlog. PG&E is collaborating with Picarro to improve the emission measurement performance of the system and Super Emitter program. This includes software improvements, dashboard development for quality control (QC) and QC of mobile leak surveys and explore the development of validation protocol across technologies.

Leak repair efforts will continue at its regular pace as described in the PG&E's 2020 GRC as follows:

- PG&E will continue fixing all Grade 1 and Grade 2 leaks as required. In accordance with the Commission's GO 112-F, PG&E repairs all Grade 1 leaks immediately and Grade 2 leaks within 12 months, with a six-month recheck.

- PG&E will also find and repair up to the forecasted number leaks that emit the highest amounts of methane in the system (the "Super Emitters") and will find and fix all above ground Grade 3 leaks within three years. PG&E's forecast is based on finding and repairing approximately 700 Super Emitter leaks during the period from 2018 - 2022. In accordance with this forecast, in 2020-2021, PG&E will repair up to 100 Grade 3 Super Emitters leaks per year identified in the accelerated leak surveys described above.

[9] Non-Super Emitter (NSE) emissions is calculated using the EF NSE emission rate of 0.035 from the 2018 Natural Gas Leakage Report for the Leak Abatement OIR, Appendix 4, Found 2018 - LS tab, column AA. The calculation assumes the leak stays open for three years, which is the survey interval.
[10] The cost effectiveness of the program was calculated by dividing the total 2018 and 2019 forecasted expenses ($5.5M) by the total forecasted abatement for the same period of time (248 MMscf). The total forecasted expenses included Super Emitter surveys and repairs.
[11] Super Emitter (SE) emissions is calculated using the EF SE emission rate of 0.646 from the 2018 Natural Gas Leakage Report for the Leak Abatement OIR, Appendix 4, Found 2018 - LS tab, column AA. The calculation assumes the leak stays open for three years, which is the survey interval.

- PG&E will find and fix all above ground Grade 3 leaks within three years.

- PG&E will continue to monitor below ground Grade 3 leaks as allowed under the Commission's GO 112-F. In addition, given the low cost effectiveness of below ground grade 3 leaks repairs as discussed above, PG&E proposes to limit the number of below ground Grade 3 leak repairs to approximately 2,000 leaks per year which is consistent with its 2020 GRC forecast, unless the Commission directs some other pace of repair higher or lower than approximately 2,000 leaks per year.[12]

  Repairing approximately 2,000 below ground Grade 3 leaks per year during 2020 and 2021 will not result in the repair of all Grade 3 leaks within three years, or the elimination of PG&E's Grade 3 leak backlog as defined by D.17-06-015, COL 23. However, given the low cost effectiveness of such repairs, and the Commission's concerns, a limited pace of repairs is appropriate. PG&E estimates that there will be 20,257 below ground Grade 3 leaks remaining in the backlog after June 19, 2020.

- PG&E will continue to repair any below-ground Grade 3 leak that develops into a higher-grade leak consistent with the timelines set forth above and will continue to remove leaks that no longer exist from the monitoring program.

There is overlap that with the Best Practice 15, which proposes transitioning to a risk-based leak survey that aims at optimizing leak survey frequencies but in no case will exceed the five-year compliance leak survey requirements. As a result, leaks in higher risk areas will be detected and Grade 1 and 2 leaks found will be repaired sooner than the traditional five-year compliance leak survey.

Part 3. Abatement Estimates

Based on 2018 leak repair data and assuming that leaks are open for three years, the emissions per Super Emitter leak is 707 mscf and for non-Super Emitters, the emissions is 38 mscf per leak. The emissions saved from the repair of one Super Emitter leak is equal to the repair of approximately 18 non-Super Emitter leaks.

Based on the proposed plan, repair of up to 100 Super Emitter leaks per year will abate approximately 70,700 mscf/year. Repair of up to 2000 below ground grade 3 leaks will abate approximately 76,000 mscf/year.

Part 4. Cost Estimates and Average Annual Revenue Requirement

The cost estimates and annual revenue requirements for this measure has been forecasted in PG&E's 2020 GRC. Once a leak is verified and graded, PG&E schedules repair or replacement

[12] PG&E's 2020 GRC settlement filed December 20, 2019 provides that the two-way balancing account NERBA be kept open after 2019 and retained through 2022 for the sole purpose of tracking the costs associated with below ground Grade 3 leak repairs under Best Practice 21. Article 4, Section 4.1.1.1 of Settlement Agreement attached to the Joint Motion filed by the settling parties in A. 18-12-009.

work to remediate the leak. There are two types of response to remediate leaks: corrective maintenance where damaged or failed facilities are repaired (expense) or asset replacement (capital) where new assets are installed to replace the failed asset.

The following summarizes the 2020 GRC expense forecast for 2020 for below ground gas distribution leak repairs, regardless of leak grade.

- Corrective Maintenance, Service Leak Below Ground (MWC[13] FIP): $13.951 million
- Corrective Maintenance, Main Leak (MWC FIG): $19.776 million
- Corrective Maintenance, Service Main Leak Above Ground (MWC FIH): $5.719 million

The following summarizes the 2020 GRC capital expense for gas service replacements, regardless of leak grade.

MAT[14]	**Activity**	**2020 Forecast**	**2021 Forecast**
50G	Simple Gas Service Replacement	$24.765 million	$26.849 million
50M	Complex Gas Service Replacement	$6.828 million	$7.448 million

Part 5. Cost Effectiveness/Benefits

As stated in Part 1 above, based on the 2018 leak repair data, the cost per mscf for below ground grade 3 leak repair was $197/mscf. The Super Emitter leak repair cost per mscf is an order of magnitude less at $8/mscf. Therefore, Super Emitter leak repairs continues to be a more cost-effective measure in reducing emissions from gas distribution leaks over below ground grade 3 leak repairs.

[13] MWC = Major Work Category
[14] MAT = Maintenance Activity Type

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. Standards Engineering periodically evaluates tools, technology, and procedures to address changes in code and compliance.

PG&E's Gas Design Standard H-10 includes the High-Pressure Regulator (HPR) pre-fabrication design which replaces many threaded connections shown in older legacy designs with socket welded connections greatly reducing leak potential. Prefabricated meter set risers from Lyall have aluminum rich urethane applied to the base of the riser valve and that is heated to allow the material to form a better seal below the riser valve. This is in addition to the thread sealant that is applied. Perfection risers utilize a similar sealant solution. These superior thread sealants lead to reduced leaks on meter sets.

In the 2018 Compliance Plan period, PG&E published the following guidance documents:

- New utility procedure TD-4160P-72, "Seal Welding"
- Revision of Utility Procedure TD-4150P-110, "Steel Bolt-On Saddle Punch Tee" to add the following: "IF saddle punch will be abandoned in place, THEN weld cap to tee outlet" to avoid threaded component being backfilled."
- Revision to Gas Design Standard B-17, "Pipe Thread Sealants", to allow the RectorSeal T Plus 2 for use on distribution applications. This updated was based upon the OTD study to evaluate the performance of commercially available pipe thread sealant materials to lock and prevent gas leakage on metal piping and fittings.

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 reductions.

Part 2. Proposed New or Continuing Measure

PG&E will continue to utilize its existing standards update process for pipe fitting specifications as it reviews 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, emission reductions 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 Standard Engineering team. Funding for Standards Engineering work has been accounted for in PG&E’s rate cases under Operational Management and Operational Support. No incremental funding is requested.

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

Historically, PG&E reduced methane emissions at the Compression & Processing (C&P) and regulator stations as part of planned station projects. Examples include the installation of electric/hydraulic actuators that have no emissions at gas terminals, and installation of Becker controllers that are classified as no bleed devices within regulator stations, as well as C&P facilities. Where feasible, compressed air is used as a control gas to eliminate the need of natural gas (e.g., the Milpitas Terminal uses air for regulating valve controllers).

PG&E has existing programs in place for systematically replacing the aging and obsolete equipment at both the gas transmission C&P and regulator stations. Replacing the aging controllers to address obsolescence also has an added benefit of reducing the overall stations emissions.

For 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 C&P station and underground storage facilities by either replacing it with intermittent or low bleed controllers, removing the device, or converting it to air. In 2018-2019, a total of 112 high bleed pneumatic devices at PG&E's C&P and storage facilities were retrofitted or removed.

PG&E has reciprocating compressors that are currently depressurized when placed in standby. In 2018, PG&E began retrofitting two of these compressors to allow them to safely remain pressurized while in standby, substantially reducing the number of blowdowns annually.

For Transmission Measurement & Control Station Facilities:

PG&E has started to remove and replace the high bleed devices (Bristol controllers, Moore 74G and Fisher Positioners) with low bleed devices at its regulator stations. Controllers installed on an obsolete actuator and plug valve were replaced with a new ball valve and actuator. Most of the high bleed devices were removed and replaced during the complex station rebuilds, routine capital work such as valve replacements or when stations are decommissioned as outlined in the 2019 GT&S work plan. In 2018-2019, PG&E replaced a total of 16 high bleed controller replacements at six regulator 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

Emission factors from Appendix 09 of the Natural Gas Leakage Report for Leak Abatement OIR were used to characterize high-bleed controllers (18.6 scfh), intermittent bleed controllers (2.4 scfh) and low-bleed controllers (1.4 scfh). For the emission calculation, new intermittent low-bleed controllers are assigned the emission factor of low-bleed devices.

The difference between the emission factors of the existing device and the replacement device is the benefit of installing a new controller. In 2018-2019, 128 high-bleed controllers have either been removed or replaced at C&P, storage, and regulator facilities. Although this would have resulted in a decrease in emissions, PG&E collected more detailed data from individual facilities on all venting components as part of an inventory for the CARB Oil and Gas Rule and accounted for devices previously not considered pneumatics. This resulted in in an overall higher device count and higher emissions estimate. Therefore, there was little change in the overall component emissions from transmission M&R stations and storage facilities. The 2015 emissions from transmission M&R stations and components at storage facilities are 579 MMscf and 10.6 MMscf, respectively. In 2018, emissions from transmission M&R stations and components at storage facilities were 574 MMscf and 11.2 MMscf, respectively.

<u>Part 2. Proposed New or Continuing Measure</u>

For 2020-2021, PG&E plans to replace/remove 10 high bleed controllers at two M&C stations. There will be approximately 22 remaining high bleed controllers from the M&C stations that will be replaced/removed in 2022 and beyond.

The replacement of high bleed devices at C&P stations and underground storage facilities are being addressed as part of the CARB Oil and Gas Rule. There are no incremental requirements associated with this Best Practice.

<u>Part 3. Abatement Estimates</u>

As stated in the 2018 Compliance Plan, the total yearly emissions reduction is estimated to be 18.4 MMscf per year from retrofitting or removal of these devices.

<u>Part 4. Cost Estimates and Average Annual Revenue Requirement</u>

Replacement or removal of high bleed controllers will be performed as part of station rebuilds, which are forecasted in the 2019 GT&S Rate Case. No additional funding is requested for this measure.

<u>Part 5. Cost Effectiveness/Benefits</u>

Replacements or removal of the remaining high bleed pneumatic device at Regulator stations will be part of planned station rebuilds. It is difficult to carve out the cost of replacing or removing these components, therefore, cost effectiveness cannot be specifically calculated. However, cost effectiveness is achieved by replacing or removing these components as part of an overall project.

CHAPTER 14: DAMAGE PREVENTION

Part 1. Evaluate the Current Practices Addressed in this Chapter

Public Education

PG&E has a comprehensive public awareness program that exceeds regulatory requirements 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 had roughly 3,001 calls in 2018 and 5,858 calls in 2019.

PG&E's Dig-in Reduction Team (DiRT) provides in-person safe excavation trainings, free of charge to the public. In 2018 and 2019, PG&E provided 226 and 148 classes, respectively.

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 2019, as a result of these ongoing programs, PG&E experienced 1.04 dig-ins per 1,000 USA tickets, which exceeded its first quartile target of 1.23 dig-ins per 1,000 tickets.

Stand-by Employees

PG&E currently requires stand-by employees to be present when excavation work is done within 10 feet of gas transmission lines.[15] This is communicated to excavators through the Underground Service Alert (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. See the Supplemental Section below to view Utility Procedure TD-5811P-1300, section 6.4.

Dig-In Reduction Team

PG&E's DiRT investigates and educates excavators who damage PG&E's underground facilities. The team 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 team 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 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

[15] 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 exceeds the regulation and adheres to best practice.

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

In the 2018 Compliance Plan, PG&E stated that the total emissions from dig-ins was 208 MMscf, of which 127 MMscf were attributed to distribution dig-ins and the remaining 81 MMscf were attributed to transmission dig-ins. PG&E estimated an annual reduction of 3.1 MMscf (using 2015 emissions as the baseline). In the 2018 annual emissions report, PG&E had fewer damages on the transmission system and reported 258 Mscf in emission resulting from transmission system damages, which was a 99.7 percent decrease from the 2015 baseline.

With regard to the distribution system damages, PG&E refined its calculation methodology and increased its repair efforts in 2018. As a result, the 2015 baseline emissions from distribution system damages was updated from 127 MMscf to 146 MMscf. In 2018, PG&E reported 28 MMscf from distribution system damages, which was an 80 percent decrease from the adjusted 2015 baseline.

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 2020 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 vary from year to year, depending upon the number of construction projects that occur in that particular year. As stated above, in 2018, PG&E had an increase in construction activities in its distribution system; however, the reduction in emissions seen is partially due to a refined calculation methodology for distribution pipeline damages as well as PG&E's increased repair effort.

Part 4. Cost Estimates and Average Annual Revenue Requirement

PG&E's Damage Prevention public education, stand-by monitor, and DiRT costs and annual revenue requirements are forecasted in PG&E's rate cases as follows:

Public Education and Dig-In Reduction Team (from 2020 GRC):
2020 Forecast: $2.480 million

Stand-by Monitors (from 2019 GT&S Rate Case):
2020 Adopted Forecast: $9.764 million
2021 Adopted Forecast: $9.999 million

No incremental work is planned to comply with this Best Practice, therefore, no additional funding is requested.

Part 5. Cost Effectiveness/Benefits

This measure is the implementation of programs to reduce dig-ins; therefore, emissions reduction cannot be calculated based on this measure. Emissions from transmission and distribution dig-ins and year-over-year emissions reductions are reported in PG&E's Natural Gas Leakage Report for the Leak Abatement OIR. No incremental work is planned to comply with this best practice.

CHAPTER 15: R&D PROJECTS

Part 1. Evaluate the Current Practices Addressed in this Chapter

Part 1 is not applicable because the R&D projects proposed under this Measure are new projects. The projects are forward looking; therefore, this Best Practice cannot be compared to the 2018 Compliance Plan.

Part 2. Proposed New or Continuing Measure

During the 2020 Compliance Plan period, PG&E's R&D and Innovation team will be pursuing the following projects:

Project 1: Regulator Station Emission Factor

PG&E proposes to update the regulator station emission factor through a 2020 NYSEARCH project. The project objective is to develop a classification framework and methodology that will provide more accurate quantitative estimation of methane emissions at regulator stations. The project goal is to show that the customization of emissions through classification of different types of equipment at regulator stations is a valid method that can improve emission calculation accuracy.

The project will evaluate various commercial emission detection and monitoring devices and techniques to confirm their accuracy in quantifying the emissions at regulator stations.

Project 2: Meter Set Leak Quantification

PG&E proposes to calculate meter set emissions using a bubble size-based approach. Meter set leaks are soap tested and repaired on an immediate response or scheduled basis. In a study with GTI and CARB, the majority of the meter set leaks found were small in size and represented an emission rate of less than 0.001 scfh. In Q3 2019, PG&E piloted a program to take close-up photos of the above ground leak bubble sizes. The photos were then uploaded onto an electronic database and classified based on the GTI's bins. The classifications will be used to quantify the emissions based on representative emission rates from GTI's study.

While no additional technology is expected to be required for this program, the field personnel will need to be trained on the bubble size classifications. The training will occur during the rollout of the updated procedure. The PG&E procedure TD-4110P-09 has been updated to include bubble size classifications. The "Inspect" mobile application was updated to include a bubble classification field. The procedure was published December in 2019, with an effective date of July 2020.

Project 3: Flaring Alternative

PG&E proposes to pursue new methodologies to reduce methane emissions from gas operations activities. NYSEARCH and Stanford is looking into an alternative to flaring by catalytically oxidizing methane at lower temperatures. In Phase 1, Stanford developed a catalyst that is 10x more reactive than commercially available products. In Phase 2, they will attempt to raise the reactivity by 2-5x more and build a prototype device.

The technology is being developed through R&D. The final technology implemented will depend upon those results. This project will further reduce emissions from Non-Emergency Blowdowns.

Project 4: ZEVAC Evaluation

PG&E plans to explore the use of ZEVAC technology in gas operation activities. ZEVAC uses compressed air to eliminate emissions. The compressed air is used to suction the pipeline segment and compresses the gas into an adjacent pipeline or tank. The intake could then be discharged back into the system.

ZEVAC technology will be assessed for use in reducing emissions from non-emergency blowdowns and has the potential to further reduce emissions from non-emergency blowdowns.

a) Best Practices(s) 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 how they propose to address quantification. Utilities shall work together, with CPUC and ARB 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

R&D Projects 1 and 2 will not directly abate methane emissions, but rather provide PG&E with the ability to directly calculate emissions from its compressor stations, regulator stations, and meter set assemblies. R&D Projects 3 and 4 will evaluate other technologies to determine the amount of emissions abated when implemented for non-emergency blowdowns.

Part 4. Cost Estimates and Average Annual Revenue Requirement

In PG&E's 2020 GRC, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects. No incremental funding is being requested in this Compliance Plan.

Part 5. Cost Effectiveness/Benefits

These R&D projects will quantify emissions from regulator stations and meter set assemblies. In addition, the R&D team will also be evaluating other alternatives that can further reduce non-emergency blowdown emissions.

As stated in footnote 3, quantifying emissions from meter set assemblies and regulator stations will enable PG&E to move to direct emissions calculations. This will also allow PG&E to better understand meter set leaks and allocate appropriate repair time. The bubble classification process started in Q1 2020; therefore, no data is available to demonstrate its cost effectiveness.

SECTION C. SUPPLEMENTAL MATERIALS

1. Measure 2: Corporate Policy ENV-03, Climate Change Principles Policy
2. Measure 3: Utility Standard TD-5601 S Greenhouse Gas Emission Reduction
3. Measure 3: Utility Procedure TD-5601P-01 Reduction of Greenhouse Gas Emissions from Planned Transmission Pipeline Blowdowns
4. Measure 8: Field Testing of Miniature Ethane and Methane Sniffer
5. Measure 8: NYSEARCH Methane Sniffer Small Unmanned Aerial System
6. Measure 8: Bridger Photonics and Kairos Aerial Methane Detector and Quantification
7. Measure 8: OTD Advanced Leak Detection Technologies for Grading Leaks
8. Measure 8: Evaluating Emissions from Transmission MR Stations
9. Measure 9: OTD Evaluate Gas Imaging Technologies
10. Measure 9: Stanford Micro Electrochemical Methane Sensor
11. Measure 10: OTD Estimating Flow Rate of Above Ground Leaks Using Soap Test
12. Measure 10: NYSEARCH Classification Reg Station Emissions
13. Measure 10: OTD LDAR Modeling for Distribution Systems
14. Measure 10: OTD Framework for Company Specific Emission Factor Development
15. Measure 11: OTD Leak Repair Prioritization
16. Measure 12: Utility Procedure TD-4160P-72, Seal Welding
17. Measure 12: Utility Procedure TD-4150P-110, Steel Bolt-On Saddle Punch Tee
18. Measure 12: Gas Design Standard B-17, Pipe Thread Sealant
19. Measure 12: NYSEARCH Reducing Methane Emissions at Threaded Connections
20. Measure 14: Utility Procedure TD-4412P-05 Excavation Procedures for Damage Prevention
21. Measure 15: NYSEARCH Methane Oxidation Catalysts for Reduction of Emissions in Flaring
22. Measure 15: OTD Methane Recovery Purging Gas Pipes into Service

SECTION D. CONCLUSION

PG&E's 2020 Compliance Plan will continue its progress toward meeting the emissions reduction goals of 20 percent and 40 percent by 2025 and 2030, respectively. Beginning to transition to a risk-based leak survey and continued use of Picarro to facilitate leak detection will enable PG&E to detect more leaks in higher risk areas. In addition, PG&E anticipates further emissions reductions from applying non-emergency blowdown reduction strategies to local gas transmission projects and stations. Lastly, in the next two years, PG&E's R&D team will continue to conduct research and development studies to develop new technologies to enable methane emission reduction, refine emission factors for more accurate data for emissions reporting, and propose additional emission reduction activities are both meaningful and cost-effective at its compressor stations, regulator stations, and meter set assemblies.

Climate Change Principles Policy

Policy Statement:

Meeting the challenge of climate change is central to PG&E's vision of a sustainable energy future. Consistent with our vision, PG&E works to reduce greenhouse gas (GHG) emissions and environmental impacts from our operations, and acts as a valuable partner to do so in California and beyond. PG&E also builds climate resilience through taking actions to adapt to and prepare for a changing climate and associated weather patterns that could affect our assets, infrastructure, operations, employees and customers.

PG&E is committed to achieving more sustainable operations by:

- Reducing emissions of methane, a potent greenhouse gas released from the operation of natural gas infrastructure, by implementing Senate Bills 1371 and 1383, which address leak abatement and short-lived climate pollutants, respectively.
- Making our facilities more energy efficient and sustainable; increasing clean vehicles and fuels in our fleet; and adopting environmentally responsible products and services.
- Engaging with our customers to help them use less energy and better manage their energy footprint through solutions that include energy efficiency and demand response, clean and renewable energy, storage, and low-carbon transportation fuels and fueling infrastructure.
- Integrating the best climate science into PG&E decision-making and asset planning to mitigate climate risks and build resilience to climate-driven impacts over the long term.

PG&E advocates for policies that:

- Position California and the nation to achieve economy-wide emissions reductions consistent with limiting the increase in global average temperature to less than 2° Celsius above pre-industrial levels.
- Support cost-effective achievement of GHG goals through providing flexibility in GHG emission-reduction strategies, covering all major emitting sectors, and fostering innovation and technology.
- Support well-designed carbon pricing mechanisms, including California's cap-and-trade program, that enable harmonization across jurisdictions over time through strategies such as linkage.
- Promote GHG reductions beyond California's borders, with California positioned as a key policy innovator, technology exporter and "proving ground" that supports broader decarbonization.

- Promote the use of offset credits and carbon sinks as valuable tools in reducing GHG emissions, improving local air quality, and enhancing the resilience and adaptability of natural ecosystems and communities.

- Help our customers become more climate-resilient and reduce their own GHG footprint affordably.

- Support PG&E's ability to invest in and adaptively manage a modern and resilient natural gas and electric system that can better withstand climate-related impacts and enable PG&E to continue providing safe, reliable, affordable and clean energy in the face of a changing climate.

Target Audience:
All employees of PG&E Corporation and its subsidiaries, including Pacific Gas and Electric Company.

Accountability:
The Senior Vice President, Energy Policy and Procurement, Pacific Gas and Electric Company, is responsible for ensuring our policy positions are consistent with these policy principles.

Approval:

Key Contact:	Jeff Brown, Manager, Climate Policy and Analysis
Reviewed by:	Chris Benjamin, Director, Corporate Sustainability Heather Rock, Chief, Climate Resilience Anna Foglesong, Director, Policy Analysis Mark Krausse, Director, State Agency Relations Jessica Hogle, Vice President, Federal Affairs and Corporate Sustainability Mary Kenaston, Gas Regulatory Specialist
Sponsoring Officer:	Fong Wan, Senior Vice President, Energy Policy and Procurement
Final Review by Compliance and Ethics:	11/15/2019

Approved by:	Fong Wan, Senior Vice President, Energy Policy and Procurement

Revision Notes:

Where	What Changed
Policy Title, Policy Statement, Accountability, and Approvals	Revised title from Climate Change Policy to Climate Change Principles Policy. Revised policy principles to reflect compliance requirements, regulatory and legislative changes, and organizational changes. Supersedes Corporation Policy: ENV-03 issued 6/1/2012.

Greenhouse Gas Emission Reduction

SUMMARY

This utility standard describes requirements for reducing greenhouse gas (GHG) emissions from non-emergency venting of distribution above 60 pounds per square inch gauge (psig), transmission, or underground storage infrastructure. The standard describes responsibilities of all stakeholders involved while promoting safe operations and considering alternative potential sources of supply to reliably serve customers at Pacific Gas and Electric Company (PG&E or Company), as mandated by the California Public Utilities Commission (CPUC) "Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leakage Consistent with Senate Bill 1371, Rulemaking 15-01-008," filed January 15, 2015 (Gas Leak Abatement OIR), Phase 1 Decision (D.) 17-06-015.

TARGET AUDIENCE

This utility standard applies to PG&E personnel in the following areas: gas control, gas system planning (GSP), gas pipeline operations and maintenance (GPOM), pipeline engineering and design, plant engineering, project management, transmission project clearance operations (TPCO), estimating, and liquid natural gas (LNG) / compressed natural gas (CNG).

TABLE OF CONTENTS

REQUIREMENTS

1 Overview

1.1 The goal of this standard is to reduce methane emissions as much as possible during non-emergency gas transmission blowdowns while maintaining the safety and reliability of PG&E's gas system.

1.2 The following clearances are excluded from this standard:

1. Clearances without a release of gas.

2. Clearances with a chamber volume less than 50 cubic feet, as discussed in Utility Standard TD-5600S, "Tracking Greenhouse Gas Emissions."

Greenhouse Gas Emission Reduction

1.2 (continued)

3. Blowdowns isolated within a station.

4. Distribution (60 psig and below) blowdowns.

5. Blowdowns associated with maintenance clearances.

6. Blowdowns associated with emergency clearances.

> **NOTE**
>
> For purposes of this standard, "project" includes pipeline blowdowns associated with strength test, in-line inspection (ILI) upgrades, pipeline replacement, valve automation, and valve replacement work types.

1.3 Methane emission reduction must be considered for all non-emergency gas transmission blowdowns and implemented where feasible, as determined by PG&E personnel and as follows.

1. To minimize the venting of methane, reducing pressure of transmission isolation areas to the lowest operationally feasible levels through the use of the following methane emission reduction strategies:

   - Project bundling
   - Drafting
   - Cross compression
   - Flaring

2. Documenting significant factors considered in methane emission abatement decisions for all planned transmission projects.

3. Measuring all transmission blowdown and reduction amounts for all scheduled projects.

4. Completing a post-event evaluation and analysis after each blowdown to determine if further process changes are necessary.

2 Roles and Responsibilities

Role	Responsibilities
Project Engineer	• Identify in Unifier which projects have gas releases • Upload detailed operating map to ProjectWise, including planned isolation points of the clearance
Project Manager (PM)	• Ensure an accurate and up-to-date P6 schedule is maintained • Coordinate with LNG/CNG personnel • Coordinate with land and environmental • Coordinate with clearance execution team • Host pre-clearance meeting with clearance supervisor and project engineering, GSP, LNG/CNG, and land or environmental personnel, as applicable • Schedule all planned gas transmission system construction projects with enough lead time to incorporate methane emission reduction strategies • Ensure the GHG Emission Reduction Feasibility Assessment is completed in Unifier
Project Bundling Personnel	• Determine when it is practical to bundle projects
Estimating Personnel	• Provide cost estimate to PM for each methane reduction strategy under consideration as necessary • Update job estimate with additional cost for using each of the planned methane emission reduction strategies (see Requirement 1.3)
Gas System Planning (GSP)	• Determine the hydraulic feasibility of using drafting and cross compression • Document drafting and cross compression hydraulic feasibility recommendations in Unifier • Calculate the estimated natural gas to be abated for each methane emission reduction strategy under consideration, excluding project bundling • Endorse work clearance documents (WCDs) in SAP, per Utility Procedure TD-4441P-10, "System New Clearances for Gas Transmission Facilities"
Cross Compression and Flaring Personnel	• Recommend cross compression for appropriate projects • Recommend flaring for appropriate projects • Document cross compression and flaring recommendations in Unifier
GHG Process Manager	• Report data collected
Clearance Writer	• Ensure the planned methane emission reduction strategies and the associated target ending pressures are documented in the WCD in SAP
Clearance Supervisor	• Report actual pressures to gas control in accordance with TD-5600 series standard and procedures • Complete a post-blowdown event evaluation for clearances where the actual ending pressures deviate from the target pressures for each methane emission reduction strategy planned
Gas Control Center Personnel	• Enter the actual ending pressures for each methane reduction strategy into the WCD in SAP, in accordance with TD-5600 series standard and procedures • Enter any reasons for pressure variances into the WCD in SAP

Greenhouse Gas Emission Reduction

3 Record Retention

3.1 Retain records per the Record Retention Schedule.

END of Requirements

DEFINITIONS

Clearance: Permission from gas control to perform work on the gas system, work that may include operational changes or isolating energy sources.

Gas emergency: An unplanned occurrence where any of the following events or combination of events occur:

- An actual or potential hazardous escape of gas (that is, a pipeline rupture)
- An overpressure or underpressure situation
- An interruption of gas supply

Project bundling: Multiple projects or work types that share a clearance and occur in the same system location resulting in GHG emission reduction.

Work Clearance Document (WCD): The electronic clearance in SAP.

IMPLEMENTATION RESPONSIBILITIES

Gas System Operations (GSO) will work with the PG&E Training Academy to develop training and host roll-out sessions to communicate the roles and responsibilities published in this document.

Standards Engineering will issue an email communication to notify all impacted stakeholders of the new guidance documents.

GOVERNING DOCUMENT

NA

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

California Public Utilities Commission (CPUC) “Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipe Lines and Facilities to Reduce Natural Gas Leakage Consistent with Senate Bill 1371, Rulemaking 15-01-008,” filed January 15, 2015 (Gas Leak Abatement OIR), Phase 1 Decision (D.) 17-06-015

Greenhouse Gas Emission Reduction

REFERENCE DOCUMENTS

Developmental References:

Gas Technology Institute (GTI) Testing Laboratories Project 220151 report *Methods to Prevent Blowdown of Gas to Atmosphere*, December 20, 2018

Utility Procedure TD-4444P-02, "Gas Transmission Control Center Emergency Response"

Utility Standard TD-4441S, "Gas Clearances"

Supplemental References:

Utility Procedure TD-4441P-10, "System New Clearances for Gas Transmission Facilities"

Utility Procedure TD-5600P-01, "Tracking Chamber Volumes for Gas Transmission Stations"

Utility Procedure TD-5600P-02, "Tracking Chamber Volume for Gas Transmission Pipeline"

Utility Standard TD-5600S, "Tracking Greenhouse Gas Emissions"

APPENDICES

NA

ATTACHMENTS

NA

DOCUMENT RECISION

NA

DOCUMENT APPROVER

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DOCUMENT OWNER

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DOCUMENT CONTACT

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(Document contact may change after publication. To find the current document contact, see the Gas Standards and Procedures Responsibility List.)

Greenhouse Gas Emission Reduction

REVISION NOTES

Where?	What Changed?
Entire document	This is a new utility standard.

Pacific Gas and Electric Company®

Reduction of Greenhouse Gas Emissions from Planned Transmission Pipeline Blowdowns

SUMMARY

This utility procedure applies to gas transmission pipeline assets and defines the steps for Pacific Gas and Electric Company (PG&E or Company) to reduce greenhouse gas (GHG) emissions from planned pipeline blowdowns.

Level of Use: Informational Use

TARGET AUDIENCE

This utility procedure applies to PG&E personnel in the following areas: gas control, gas system planning (GSP), gas pipeline operations and maintenance (GPOM), pipeline engineering and design, plant engineering, project management (PM), transmission project clearance operations (TPCO), estimating, and Liquid Natural Gas (LNG) / Compressed Natural Gas (CNG).

SAFETY

NA

BEFORE YOU START

Ensure access to Unifier.

TABLE OF CONTENTS

PROCEDURE STEPS

1 Identify Applicability

1.1 In Unifier, the project engineer completes the project scoping section of the GHG Emission Reduction Feasibility Assessment.

1. IF no release of gas is planned for a project,

   THEN the remainder of this document does not apply.

2 Strategize to Reduce Methane Emissions

2.1 Consider project bundling.

1. To prevent multiple venting of the same piping and thereby reduce GHG emissions, PG&E bundling personnel determine when it is practical to bundle projects.

2.2 Evaluate feasibility of drafting, cross compression, and flaring.

1. In Unifier, the GSP Engineer evaluates the hydraulic feasibility of using drafting or cross compression by completing the appropriate section of the GHG Emission Reduction Feasibility Assessment.

2. IF the GSP engineer recommends using drafting for this project,

   THEN the GSP engineer documents the proposed drafting plan AND estimates the volume of natural gas to be abated using this reduction strategy.

3. IF the GSP engineer recommends cross compression or flaring for this project,

   THEN the GSP engineer documents the estimated natural gas to be abated using this reduction strategy AND completes the Cross Compression Request for Proposal (RFP) in Unifier.

   a. Cross compression and flaring personnel complete a desktop feasibility assessment to determine whether cross compression is feasible for this project.

   b. IF cross compression personnel determine that cross compression is feasible,

      THEN the project manager (PM) sets up a site visit with cross compression personnel to make a final determination on cross compression feasibility for the project.

4. In Unifier, cross compression and flaring personnel evaluate the feasibility of using flaring by completing the flaring section of the GHG Emission Reduction Feasibility Assessment

2.3 Evaluate drafting, cross compression, and flaring recommendations.

1. The project estimator provides the PM with an estimated cost for executing each recommended methane emission reduction strategy when necessary.

2. The PM engages with additional project stakeholders to review the recommended methane emission reduction strategies, considering the following:

2.3 (continued)

- Safety
- Value of gas estimated to be released
- Cost to execute the reduction strategy and amount of gas estimated to be abated
- Effects on customers
- Environmental permit requirements
- Land acquisition requirements

3. In Unifier, the PM documents which methane emission reduction strategies are planned for this project.

3 Finalize Methane Abatement Plan

3.1 The PM ensures the GHG Emission Reduction Feasibility Assessment is complete in Unifier. The complete assessment includes the following information:

1. Methane emission reduction strategies planned.
2. Estimated natural gas to-be abated for each methane emission reduction strategy planned.
3. Target ending pressures for each methane emission reduction strategy planned.
4. If drafting, cross compression, OR flaring is **not** planned, the reason why.

3.2 The PM targets GHG Emission Reduction Feasibility Assessment completion in Unifier by the time the project completes its 60% Project Review Acceptance.

3.3 The PM builds time into the project schedule to execute the reduction strategies included in the methane abatement plan for this project.

3.4 The project estimator updates the project's job estimate to include any additional costs to execute the methane abatement plan.

4 Transfer Methane Abatement Plan to Work Clearance Document (WCD)

4.1 The GSP Engineer and PM review and update the GHG Emission Reduction Feasibility Assessment in Unifier before clearance execution.

4.2 The clearance writer prepares the WCD according to Utility Standard TD-4441S, "Gas Clearances," and Utility Procedure TD-4441P-10, "System New Clearances for Gas Transmission Facilities."

4.3 The clearance writer ensures the planned methane emission reduction strategies and the associated target ending pressures are included in the WCD in SAP.

4.4 The GSP engineer reviews the WCD to ensure the methane abatement plan has been included in the WCD before endorsing the WCD in SAP per Utility Standard TD-4441S and Utility Procedure TD-4441P-10.

5 Complete Post-Blowdown Event Evaluation

5.1 The clearance supervisor executes the clearance per Utility Procedure TD-4441P-10.

5.2 The clearance supervisor notifies gas control personnel of the actual ending pressure for each methane emission reduction strategy executed per Utility Procedure TD-5600P-02, “Tracking Chamber Volume for Gas Transmission Pipeline.”

1. IF the actual pressures do **not** match the target ending pressures for the planned methane emission reduction strategy OR the methane emission reduction strategy was **not** executed,

   THEN the clearance supervisor provides a reason for this variance to gas control personnel as part of the post-blowdown evaluation.

   a. Gas control personnel enter the reason for the variance in the WCD in SAP.

   b. GHG personnel review the post-blowdown event evaluations and makes changes to improve the GHG emissions reductions process as necessary.

6 Record Retention

6.1 Retain records per the Record Retention Schedule.

END of Instructions

DEFINITIONS

Clearance: Permission from gas control to perform work on the gas system, work that may include operational changes or isolating energy sources.

Project bundling: Multiple projects or work types that share a clearance and occur in the same system location resulting in GHG emission reduction.

Work Clearance Document (WCD): The electronic clearance in SAP.

IMPLEMENTATION RESPONSIBILITIES

Gas System Operations (GSO) will work with the PG&E Training Academy to develop training and host roll-out sessions to communicate the roles and responsibilities published in this utility procedure.

Standards Engineering will issue an email communication to notify all impacted stakeholders of the new guidance documents.

GOVERNING DOCUMENT

TD-5601S, "Greenhouse Gas Emission Reduction"

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

California Public Utilities Commission (CPUC) Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipe Lines and Facilities to Reduce Natural Gas Leakage Consistent with Senate Bill 1371, Rulemaking 15-01-008, filed January 15, 2015 (Gas Leak Abatement OIR), Phase 1 Decision (D.) 17-06-015.

REFERENCE DOCUMENTS

Developmental References:

Gas Technology Institute (GTI) Testing Laboratories Project 220151 report *Methods to Prevent Blowdown of Gas to Atmosphere*, December 20, 2018

Utility Procedure TD-4444P-02, "Gas Transmission Control Center Emergency Response"

Utility Procedure TD-5600P-01, "Tracking Chamber Volumes for Gas Transmission Stations"

Utility Standard TD-5600S, "Tracking Greenhouse Gas Emissions"

Supplemental References:

Utility Procedure TD-4441P-10, "System New Clearances for Gas Transmission Facilities"

Utility Procedure TD-5600P-02, "Tracking Chamber Volume for Gas Transmission Pipeline"

Utility Standard TD-4441S, "Gas Clearances"

APPENDICES

NA

ATTACHMENTS

NA

Reduction of Greenhouse Gas Emissions from Planned Transmission Pipeline Blowdowns

DOCUMENT RECISION

NA

DOCUMENT APPROVER

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DOCUMENT OWNER

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DOCUMENT CONTACT

Natalie Newman, Senior Gas Engineer, Gas Control Strategy and Support

(Document contact may change after publication. To find the current document contact, see the Gas Standards and Procedures Responsibility List.)

REVISION NOTES

Where?	What Changed?
Entire document	This is a new utility procedure.

1) BEST PRACTICE ADDRESSED

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.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

NASA JPL Miniature Methane Sniffer Field Testing

Type of program: In-house pilot testing

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

The objective of this project is to perform field tests on a series of industrial methane sniffer prototypes developed by NASA JPL and built by RKI Instruments. The advantage of this handheld sniffer compared to commercially available products are its high sensitivity to methane (ppb level) to enable faster localization of small leaks, the ability to detect ethane for biogas determination and the integration of high quality GNSS localization to more effectively report leaks in gas operator asset management systems.

In addition to the handheld detector, RKI is developing a sensor for mounting on Unmanned Aerial System (UAS) based on the same technology. Leveraging the compact form factor and lightweight design of the sensor, a methane sensing UAS allows leak survey in difficult-to-reach areas or following an emergency. The sensor is built to be platform agnostic and can be procured by UAS service providers to add leak survey feature to their aircraft.

This project will test the different prototypes in field conditions to validate the performance of the equipment and provide feedback to the development team.

4) ANTICIPATED OR EXPECTED RESULTS

A successful outcome of this project will pave a path to the commercialization of an affordable miniature handheld methane detector for leak survey. A separate product for UAS is developed in parallel and, if successful, will be available to UAS service providers for integration with their aircraft platforms.

The evaluation criteria that will be used to determine the usability of the device are among others: cost, ease of use, ergonomic fit, measurement accuracy, battery life, durability, ability to locate leaks, etc.

5) EMISSIONS IMPACT

The end products will enable faster localization of leaks, including small non-hazardous leaks, to facilitate faster repair. The device may be used for leak quantification helping in refining emission factors.

6) MILESTONES

Anticipated Start Date: Q1 2018

Anticipated End Date: Q4 2020

Task 1 Field Test first prototype: Q3 2018

Task 2 Field Test second prototype: Q4 2019

Task 3 Field test final prototype: Q4 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

User feedback will be gathered during the field test using survey forms. Performance criteria will include: ease of use, ergonomic fit, measurement accuracy, battery life, durability, ability to locate leaks, etc.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The expected cost is $177,000 without co-funding opportunities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E’s 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template. PG&E may eventually purchase the sensors once commercialized.

11) REFERENCES

L. Christensen “Fast, Accurate, Automated System to Find and Quantify Natural Gas Leaks. Final Report. ROW-3H” PRCI, June 2019

1) BEST PRACTICE ADDRESSED

   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.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

   Methane Sniffer Small Unmanned Aerial System (ms-sUAV) (M2014-001 Phase 2)

   Type of program: Development and Demonstration of new technology, collaborative project (NYSEARCH)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

   The objective of this project is to develop and demonstrate a micro-UAS for leak survey on distribution pipelines. A major application of this technology is leak detection in areas that are difficult to survey with road vehicles or on foot. The methane sensor that is integrated on the UAS has been developed by NASA JPL, has superior sensitivity to methane, is lightweight, and comes in a small form factor. The project will also evaluate the ability of the UAS system to localize leaks after detection. The learnings from this study will be used to develop an automated system for localization following detection.

4) ANTICIPATED OR EXPECTED RESULTS

   The results will support the use of small UAS to perform automated leak surveys of distribution systems as well as at gas facilities such as compressor stations, storage facilities and regulations stations.

   To be viable for operational use, this technology will have to outperform existing direct measurement methods in one or more of the following criteria: localization and measurement time and accuracy, and cost.

5) EMISSIONS IMPACT

   This project will provide utilities with an effective alternative tool to perform routine and emergency leak survey for areas difficult to access with road vehicles or on foot. There is no anticipated emissions reduction directly resulting from this project, but easier and more cost-effective leak survey and quantification will contribute to quicker detection and repair of gas leaks reducing methane emissions.

6) MILESTONES

   Anticipated Start Date: Q2 2017

   Anticipated End Date: Q4 2020

Task 1 Field Test first prototype: Q3 2018

Task 2 Field Test second prototype: Q4 2019

Task 3 Field test final prototype: Q4 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

   Data will be collected during controlled tests at simulated leak field and during field tests. It will include methane concentration measurements during the detection sequence to estimate the ability to detect and locate leaks in function of distance, altitude, and weather conditions.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

   The expected cost is $421,000 with co-funding from other NYSEARCH member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

   In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

    No other Advice Letter costs directly related to this template.

11) REFERENCES

L. Christensen "Fast, Accurate, Automated System to Find and Quantify Natural Gas Leaks. Final Report. ROW-3H" PRCI, June 2019

1) BEST PRACTICE ADDRESSED

   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.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

   Bridger Photonics Kairos Aerial Methane Detector and Quantification

   Type of program: In-house pilot

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

   In the past few years, Bridger Photonics has been working on the next-gen methane leak detection and quantification. The technology uses a laser-based remote sensor, which can be mounted onto a fixed wing aircraft. The laser system sweeps the area below the aircraft and creates a heat map of methane plumes it detects to provide source location indications and leak rate quantifications.

   Kairos Aerospace LeakSurveyor uses passive hyperspectral imaging from the wing of a small aircraft to construct a two-dimensional image of methane concentrations integrated along the path between the airplane and the ground. Kairos' automated processing identifies methane plumes and calculates wind-adjusted methane emission rate in scfd per mph of wind.

   Recently, considerable improvement has been made to the sensitivity of the sensing equipment. Combined with its ability to be flown on aeroplanes, large swath width, high flight altitude, these systems are promising tools for cost-effective transmission pipeline leak survey. This project will demonstrate and assess both technologies using fixed wing aircrafts.

4) ANTICIPATED OR EXPECTED RESULTS

   The project is expected to be completed in Q4 2020. If results are positive PG&E will consider Bridger Photonics and/or Kairos Aerospace leak detection and quantification technologies for Transmission pipeline surveys.

5) EMISSIONS IMPACT

   The new technology offers cost reduction compared to existing helicopter-based systems. Based on its performance it may be used to quickly detect high emission M&R stations.

6) MILESTONES

   Anticipated Start Date: Q2 2020

Anticipated End Date: Q4 2020

Task 1 Execute leak detection survey: Q2-Q3 2020

Task 2 Result Report and Comparison: Q4 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

The technologies will be tested using controlled methane releases from either a bottle or regulator station. Comparison will include detection threshold in scfh, leak rate quantifications, false positive and false negative ratio, localization accuracy, coverage and survey speed in miles/h.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The maximum expected cost is $100,000 with no co-funding from other utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

n/a

1) BEST PRACTICE ADDRESSED

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.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

Advanced Leak Detection Technologies for Grading Leaks (7.19.b)

Type of program: Basic Research project, collaborative (OTD)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?
New methane detectors for leak survey, such as the NASA-JPL RKI detector that is under development, operate differently from conventional instruments in that they don't have a pump to pull air into the system. This enables the new "open-path" sensors to have a much faster response time and higher sensitivity. However, it limits the sensors' ability to measure subsurface concentrations which is a key task in current leak grading protocol. To facilitate introduction of the "open path" sensors to the gas industry, this project will evaluate the feasibility of having an aboveground leak grading method. Once proven feasible, the next step is to develop the new leak grading procedure.

4) ANTICIPATED OR EXPECTED RESULTS
The potential benefit with using a more sensitive and responsive methane sensor is substantial. There are also intangible benefits in improving safety when more leaks are found.

5) EMISSIONS IMPACT

Once a leak grading procedure is developed, operators can reap the benefits of using advanced open path sensors such as higher sensitivity and faster response time which will improve leak detection capability and facilitate faster repair, thus reducing emissions.

6) MILESTONES

Anticipated Start Date: Q2 2020

Anticipated End Date: Q4 2020

Task 1 Compilation of existing data and study design: Q3 2019

Task 2 Field Testing: Q3 2019 - Q2 2020

Task 3 Develop leak classification procedure: Q3 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

This project will collect data through field testing and determine whether there are strong enough correlations between the mini-OPLS instrument and traditional instruments used for leak grading. If so, then a leak classification procedure will be developed using open path sensors such as the Mini-OPLS.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The total cost is $190,000 with co-funding from other OTD member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

n/a

1) BEST PRACTICE ADDRESSED

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 above ground 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.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

Transmission Metering and Regulating (M&R) Stations Emission Monitoring

Type of program: In-house testing/research

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

This internal PG&E research will install portable open-path methane sensors, commercialized by Sensit, at several transmission M&R stations to continuously monitor the ambient methane concentration from which emissions level can be derived. The results will shed light on the amount and frequency of emissions from these stations and the way new specific emission factors can be established to capture actual emissions of PG&E's regulation stations. In addition, this study will assess the ability of the methane sensor to compare emission of one station to another, and will provide data to validate methane emissions models.

4) ANTICIPATED OR EXPECTED RESULTS

The results from the study can be used to better understand the behavior of and the factors that affect emissions from transmission M&R stations, including equipment type and gas load. The data can also be used to develop a new utility-specific set of emission factors, potentially categorized by equipment type and count, to characterize emissions from transmission M&R stations. Current emission factors are believed to be outdated. Since they were established in 1996, many technological advances and improvements in maintenance practices have been implemented leading to lower amount of vented and fugitive emissions. The new emission factors from this study would provide a more accurate representation of the current state of PG&E's stations and will support the assessment of future abatement measures.

Comparison of different regulation stations will inform efforts to prioritize repairs to optimize emission abatement.

The evaluation criterion for the validity of the new emission factors is to have a statistically significant amount of data and comparison with other measurement methods.

5) EMISSIONS IMPACT

The expected outcome of the project is a revision of the emission factors for transmission M&R stations. The results will potentially establish current PG&E M&R stations' emissions and will support future efforts toward emission reduction. The specific method to account for the reductions from 2015 levels will need to be determined.

6) MILESTONES

Anticipated Start Date: Q3 2017

Anticipated End Date: Q4 2020

Task 1 Monitoring first set of stations: Q3 2018

Task 2 Monitoring second set of stations: Q3 2019

Task 3 Monitoring third set of stations: Q3 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

Data from the sensors will be analyzed in parallel with data collection. Visits with Hi-flow sampler will be made occasionally to validate the findings of stationary methane sensors.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The total cost is $100,000. There is no co-funding for this project.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

n/a

1) BEST PRACTICE ADDRESSED

BP 19: Enhanced Methane Detection

Utilities shall conduct frequent leak surveys and data collection at above ground 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 above ground and pressures above 300 psig only). At a minimum, above ground leak surveys and data collection must be conducted on an annual basis for compressor stations and gas storage facilities.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

Evaluate Gas Imaging Technologies for LDC – Additional Scope (7.16.b)

Type of program: Research existing technologies, collaborative project (OTD)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

The objective of this project is to evaluate the use of gas imaging technologies for various applications within the gas industry. Specific applications will include the use of these tools for methane emissions quantification (e.g., measuring leak rate) and as a tool for first responders during leak investigation and grading. Cameras to be tested include:

- TelOps Hyperspectral Imaging Camera
- VIRA Gas Imaging camera
- FLIR GF-620 Optical Gas Imaging Camera
- FLIR GF-320 Cooled IR camera
- FLIR GF-44 Gas Find IR

4) ANTICIPATED OR EXPECTED RESULTS

A successful outcome will determine if the use of gas imaging cameras is a viable option for identifying gas leaks and quantifying methane emissions. Current tools on the market to quantify emissions are too cumbersome and time consuming to use on every leak (Hi-Flow Sampler). Gas imaging cameras can reduce the time required to obtain a flow rate, enabling utility companies to collect emission rate data from every leak if so desired. Gas imaging cameras can also help in the leak investigation process as methane plumes can be visualized and used as an aid in investigating difficult to pinpoint leaks. A final report summarizing the data from the technology evaluation and field demonstrations will be provided to utilities.

An intermediate report was completed in 2016 on the results of the testing with Rebellion Photonics Mini Gas Cloud Imaging camera on above and below ground leaks at GTI facility in Des Plaines, IL.[1]

The cameras' cost, detection limit, and ability to image and quantify emissions flux of underground leaks will be the major determining factors of their usability for gas utilities.

5) EMISSIONS IMPACT

On its own, this project will not contribute to emissions reduction but it will improve detection and quantification of leaks. Assuming gas imaging cameras are viable options for gas utilities, the emissions reductions can be realized once utilities adopt gas imaging cameras to detect smaller leaks. This will vary across utilities depending on the implementation opportunity and existing practices. For these reasons, the emissions reductions cannot be reasonably quantified at this point.

6) MILESTONES

Anticipated Start Date: Q3 2017

Anticipated End Date: Q2 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

The controlled testing portion will be done in an outdoor setting at Gas Technology Institute's pipe farm in Des Plaines, IL. The measurements made by gas imaging cameras will be validated using Hi-Flow sampler as the reference technique.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The total cost is $287,000 shared among participating OTD member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

[1] OTD, *(7.16.b) Evaluate Gas Imaging Technologies for LDC Applications - Q4 2017 Report*

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

n/a

1) BEST PRACTICE ADDRESSED

BP 19: Above ground leak surveys

Utilities shall conduct frequent leak surveys and data collection at above ground 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 above ground and pressures above 300 psig only). At a minimum, above ground leak surveys and data collection must be conducted on an annual basis for compressor stations and gas storage facilities.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

Development of a Micro Electrochemical Methane Sensor

Type of program: Technology development, collaborative project (Stanford University, SoCal Gas)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

The overall objective of this program is to develop and commercialize a "point" methane sensor that is centimeters in size, affordable, and can be used to detect leaks at meter sets or regulating stations. This phase 2 project at Stanford University will focus on developing functional prototypes of the electrochemical methane sensor and testing in a controlled environment. Sensor development will be an iterative process of designing, fabricating, characterization, and lab testing. Once a functional prototype is accomplished, there will be further integration work to package the breadboard elements in a robust shell for initial field testing. The field test will first be attempted in a controlled setting at a host utility. The deliverable for phase 2 is a functional prototype and a report/slide deck that includes the results of the controlled test.

4) ANTICIPATED OR EXPECTED RESULTS

The expected result is a functional electrochemical sensor prototype with field deployment capability.

The evaluation criteria that will be used to determine eligibility of the sensor for further testing are (among others): detection limit, battery life, ease of integration into existing network, fire safety rating, size, weight. It is not clear, at this time, the threshold values of the criteria that will ensure the deployment of the technology that is still in early stage of deployment.

5) EMISSIONS IMPACT

This project will have an indirect effect of reducing emissions by providing utilities with a set of sensors for leak detection at threaded connections. The expected contribution to emissions reduction can be realized once utilities adopt the commercialized version of the sensor at scale. The continuous monitoring of assets will lead to earlier discovery of fugitive emissions. The adoption of the sensor will vary across utilities depending on the implementation opportunity and existing practices. For these reasons, an estimate cannot be reasonably quantified at this point.

This project is not expected to have an impact on emission factors.

6) MILESTONES

Anticipated Start Date: Q2 2018

Anticipated End Date: Q4 2020

Task 1 Sensor design: Q2 2018

Task 2 Fabrication, characterization, testing: Q4 2018

Task 3 Controlled Testing: Q3 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

This project will continuously collect data from sensor testing. This data includes detection limit, battery life, measurement accuracy, reliability, and stability.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The total cost is $600,000 shared among participating utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E’s 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template. PG&E may eventually purchase several point sensors depending on the results of the study.

11) REFERENCES

n/a

1) BEST PRACTICE ADDRESSED

BP 20a: Leak Quantification

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 ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks for the purpose of tracking emissions reductions.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

Estimating Leak Flow Rate Using Soap Test (7.17.d)

Type of program: Technology development, collaborative project (OTD)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

The objective is to develop a simple method for quantifying methane emissions from small aboveground leaks using a soap test to categorize emissions with estimated leak rates. This may provide the basis for moving away from the current facility-based emission factor for Meter Set Assemblies and Metering & Regulating(M&R) Stations to a set of leak-based factors.

4) ANTICIPATED OR EXPECTED RESULTS

The expected result is a defined relationship between soap bubble formation and leakage rates.

Typical small leaks on above-ground assets are from threaded connections. A test matrix will be developed to simulate these types of leaks in a controlled laboratory environment. Leakage data at various pressures and temperatures, and soap bubble characterization will be documented.

5) EMISSIONS IMPACT

If successful, this new leak estimation methodology can assist utility operations with improving reporting accuracy and maintenance procedures. This project is to conduct basic research, potential impact on emissions cannot yet be determined.

This project is expected to have an impact on residential and commercial meter set emission factors.

6) MILESTONES

Anticipated Start Date: Q4 2017

Anticipated End Date: Q2 2020

Task 1 Soap Solution Review: Q3 2018

Task 2 Lab Testing: Q3 2018

Task 3 Field Demo/Validation: Q2 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

   See Question 4.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

   The total project cost is $189,700 shared among participating OTD member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

   In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

    No other Advice Letter costs directly related to this template.

11) REFERENCES

    n/a

1) BEST PRACTICE ADDRESSED

BP 20a: Leak Quantification

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 ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks for the purpose of tracking emissions reductions.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

Classifying Methane Emissions at Regulator Stations

Type of program: Research, collaborative project (NYSEARCH)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?
The current population-based emission factor methodology of estimating those emissions does not take into account the changing conditions at the regulation station, or the specific equipment used. The current methodology also does not allow utilities to take credit for emissions abatement efforts at these stations. The overall objective of this project is to develop a classification framework and methodology that will provide more accurate quantitative estimation of methane emissions at regulator stations.

4) ANTICIPATED OR EXPECTED RESULTS
The classification framework and methodology developed through this project will be proposed to the CPUC as an alternative to the current emissions reporting practice for regulator stations. This will allow for recognition of PG&E's emission abatement efforts at regulator stations through emissions reporting and provide an extra path forward for PG&E to achieve emission reductions of 40% below 2015 levels by 2030.

5) EMISSIONS IMPACT

The expected outcome of the project is a revision of the emission factors for transmission M&R stations. The results will potentially establish current PG&E M&R stations' emissions and will support future efforts toward emission reduction. The specific method to account for the reductions from 2015 levels will need to be determined.

6) MILESTONES

Anticipated Start Date: Q4 2019

Anticipated End Date: Q4 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

   Data collection includes a regulator station inventory and classification. Field testing will compile data on sources that produce the largest emitters.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

   The total project cost is $191,535 shared among participating NYSEARCH member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

   In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

    No other Advice Letter costs directly related to this template.

11) REFERENCES

    n/a

1) BEST PRACTICE ADDRESSED

BP 20a: Leak Quantification

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 ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks for the purpose of tracking emissions reductions.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

Leak Detection and Repair Modeling for Distribution Systems (7.17.a)

Type of program: Research, collaborative project (OTD)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

Recently, there have been a number of research programs such as ARPA-E MONITOR that have accelerated development of leak detection technologies. In the near future, operators will have many viable leak detection and repair technologies to choose from. Stanford University recently developed an open source model, Fugitive Emissions Abatement Simulation Toolkit (FEAST), for estimating the capital and labor costs of surveying and repairing leaks at well sites with different methods and equipment. This OTD project will take the FEAST model and adapt it for estimating LDAR costs for distribution systems.

4) ANTICIPATED OR EXPECTED RESULTS

This proposed model will enable us to select cost-effective technologies for performing leak survey and repair work. A small saving per leak will scale up quickly when the approach is applied to the entire system. Current method can also be reviewed and compared with existing options.

5) EMISSIONS IMPACT

If successful, this new model can assist utility operations with selecting cost-effective technologies to improve maintenance procedures. There is no anticipated emission reduction directly results from this project, but easier and more cost-effective leak survey will contribute to quicker detection and repair of gas leaks reducing methane emissions.

6) MILESTONES

Anticipated Start Date: Q4 2019

Anticipated End Date: Q3 2020

Task 1 Real Leak Data and New Technology Implementation: Q4 2019

Task 2 Model Evaluation Reporting and Web-based Deployment: Q3 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

The model will be optimized and adapted to include mobile, vehicular based surveys and to include IR technologies by adjusting model parameters. The performance of the FEAST model will also be evaluated by running the model with existing distribution leak data.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The total project cost is $130,000 shared among participating OTD member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

n/a

1) BEST PRACTICE ADDRESSED

   BP 20a: Leak Quantification

   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 ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks for the purpose of tracking emissions reductions.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

   Framework for Company Specific Emissions Factor Development (7.19.e)

   Type of program: Research, collaborative project (OTD)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

   This project will develop a framework using a statistical sampling approach to generate company-specific emission factors. This framework will include a sampling method selection process, measurement of sample representativeness, probablistic analysis of collected data, and generation of representative emission factors for a natural gas operator. The goal will be to allow companies to have a standardized approach for planning, collecting, analyzing, and validating data to establish company-specific emission factors based on operational conditions.

4) ANTICIPATED OR EXPECTED RESULTS

   The results of this study will enable the company to employ field data collection to feed into a probabilistic model to establish representative emission factors for all gas assets. This will result in higher accuracy in our annual leak abatement and greenhouse gas emission reports.

5) EMISSIONS IMPACT

   The expected outcome of the project is company-specific emission factors. The results will potentially establish current emissions and will support future efforts toward emission reduction. The specific method to account for the reductions from 2015 levels will need to be determined.

6) MILESTONES

   Anticipated Start Date: Q3 2019

   Anticipated End Date: Q3 2020

Task 1 Project Scoping: Q3 2019

Task 2 Asset Characterization and Sampling Method Recommendation: Q3 2019

Task 3 Sampling Approach and Tests for Sample Representativeness: Q4 2019

Task 4 Probabilistic approach for data analysis: Q2 2020

Task 5 Framework Development: Q2 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

The model will be optimized and adapted to include mobile, vehicular based surveys and to include IR technologies by adjusting model parameters. The performance of the FEAST model will also be evaluated by running the model with existing distribution leak data.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The total project cost is $200,000 shared among participating OTD member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

n/a

1) BEST PRACTICE ADDRESSED

   BP 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.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

   Leak Repair Prioritization (7.16.a)

   Type of program: Research, collaborative project (OTD)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

   To develop a method of prioritizing repair of non-hazardous leaks utilizing leak detection tools commonly available to the industry. Phase 2 focuses on further investigation of relationship between maximum and mean gas concentration readings, by expanding the study in sand, clay, and paved concrete with barholes.

4) ANTICIPATED OR EXPECTED RESULTS

   The results of this study will enable the leak survey crews to quickly estimate emission rates with current tools/instruments. This includes an emission rate conversion chart or charts dependent on soil type and barhole/pavement testing.

5) EMISSIONS IMPACT

   The ability to prioritize the largest leaks in our system would allow us to reduce methane emissions from our distribution system, without needing to fix every non-hazardous leak detected. Having a strong correlation to emission factors would also improve the accuracy of our annual emissions on our distribution system.

6) MILESTONES

   Anticipated Start Date: Q3 2019

   Anticipated End Date: Q4 2020

   Task 1 Project Scoping: Q3 2019

   Task 2 Soil Testing at Utilities: Q2 2020

   Task 3 Barhole and Pavement Testing: Q2 2020

   Task 4 Refine ER Conversion Charts: Q4 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

Testing will be conducted with various soil conditions and bar hole/pavement areas. Phase 2 will focus on the relationships between maximum and mean gas concentration readings, and the development of a method to estimate emission rates based on those readings. Uncontrolled equivalency testing will be conducted at utility field sites to enhance the emission rate conversion chart to include calibration of low, medium and high leak rates.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The total project cost is $170,000 shared among participating OTD member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E’s 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

n/a

Pacific Gas and Electric Company®

Utility Procedure: TD-4160P-72
Publication Date: 03/21/2018; Effective Date: 04/04/2018
Rev: 0

Seal-Welding

SUMMARY

This utility procedure describes the process for seal-welding threaded steel pipe connections within Pacific Gas and Electric Company (PG&E or the Company).

Level of Use: Informational Use

TARGET AUDIENCE

Personnel working in welding and engineering design of pipeline components

SAFETY

NA

BEFORE YOU START

NA

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PROCEDURE STEPS

1 General Information

1.1 Ensure the threaded joint to be seal-welded has enough threads of engagement to provide required strength to the connection. This is typically seven to eight threads of engagement. Any weld metal from seal-welding must not be considered as contributing strength to the threaded joint.

1.2 Ensure seal-welding will be performed using arc welding procedures qualified in accordance with American Petroleum Institute (API)-1104 or American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section IX.

Seal-Welding

1.3 Ensure welding will be performed by welders qualified in accordance with one of the following documents as applicable to the weld procedure used:

- Utility Procedure TD-4160P-30, "Welder Performance Qualification – 60 psig or Less"
- Utility Procedure TD-4160P-31, "Welder Performance Qualification – API 1104 Procedures"
- Utility Procedure TD-4160P-32, "Welder Performance Qualification – ASME Section IX"

1.4 Verify the following:

- Pipe has a wall thickness of ANSI Schedule 80 or greater.
- Threaded pipe-to-fitting connections have no more than five exposed threads.
- Pipeline or component is depressurized, including both sides of completion plug on pressure control fittings.
- Pipe or component surface is free of galvanizing, zinc coating, or cadmium plating.
- Pipe or component is not cast or malleable iron.
- Effects of welding will not damage adjacent components such as soft seats of valves.
- Pipe or component has not been previously seal-welded, disassembled, or reassembled.

1.5 Ensure parts to be seal-welded are made from weldable grade steels. The following materials manufactured in accordance with the listed PG&E specifications are considered weldable:

- Pipe listed in Gas Design Standard (GDS) A-15, "Code Numbers for Steel Pipe" or manufactured in accordance with Engineering Material Specification (EMS) 4120, "Steel Pipe Material Specification"
- Threadolets manufactured in accordance with GDS B-23, "Weldolets, Threadolets, and Sockolets"
- Forged steel pipe parts manufactured in accordance with ASME B16.11 (Refer to individual Gas Design Standards B-10 through B-15.1, as listed in the Supplemental References Section.)

Seal-Welding

1.6 Other examples of weldable and non-weldable metal specifications are listed below in Table 1.

Table 1. Weldable and Non-Weldable Metal Specifications

Weldable
ASTM Fitting Specifications A-234, A-403, A-420 A-815
ASTM Forging Specifications A-105, A-182, A-350, B-462, B-564
ASTM Piping Specifications A-53, A-106, A-252, A-333, A-381, A-671, A-672, A-691, A-312
ASTM Steel Specifications A-36, A-572, A-633
API 5L Pipe - All Grades
ASME Forged Fittings, Socket-Welding and Threads B-16.11
Mueller Fitting and Caps manufactured in accordance with ASTM A-105
Non-Weldable
API Cast Iron Piping
ASTM A-197, Malleable Iron Fitting Specification
ASTM A-126, Cast Iron Valve Specification
ANSI/ASME B16.3, Malleable Iron Threaded Fitting Specification
Mueller Cast Iron Completion Caps

2 Welding

2.1 Verify all exposed threads can be covered by the seal-weld.

1. IF more than five threads are exposed,

   THEN disassemble joint, shorten male threaded pipe end, and reassemble without thread sealants.

2.2 Verify pipe system is not pressurized and not leaking gas or fluids at proposed weld area.

2.3 Clean the weld area by using a wire brush, cleaning solvent and/or a torch to remove all dirt, paint, oil, grease, rust, and pipe thread sealant.

2.4 Pre-heat threaded connection to 150°–350°F range.

2.5 Seal-weld the threaded connection by using a branch or lap fillet weld procedure.

1. Place a seal-weld at the lap fillet location of the threaded male-by-female end connection.

Seal-Welding

2.5 (continued)

2. Make initial root pass weld.

   a. IF using the shielded metal arc-welding (SMAW) process,

      THEN use cellulosic electrodes.

3. Inspect weld for porosity and make repairs as needed.

4. Evenly deposit at least one additional layer of weld metal around the entire circumference of the joint.

5. Cover all exposed threads with weld metal.

3 Visual Inspection

3.1 Visually inspect weld per Utility Procedure TD-4160P-61, "Visual Weld Inspection for Pipeline Welds."

4 Testing

4.1 Soap test weld at 100–110 pounds per square inch gauge (psig) and at operating pressure.

1. IF operating pressure is less than 100 psig,

   THEN soap test weld at operating pressure only.

4.2 IF possible leakage from the tested joint poses an unacceptable safety risk,

THEN perform additional nondestructive examination (NDE), or hydrostatic/pneumatic pressure testing prior to placing the system in service.

5 Repairs

5.1 IF leakage is discovered during soap or pressure testing,

THEN depressurize line and verify there is no leaking gas or fluids at repair weld area.

5.2 Grind defective weld area down to sound metal.

1. Minimum repair length is half the circumference of the fitting or 2"; whichever is less.

5.3 Pre-heat entire weld from 150°–350° F.

5.4 Make repair weld with the same weld procedure that was used to make original weld.

1. A minimum of two layers is required.

5.5 Inspect weld per Section 3.

5.6 Test weld per Section 4.

5.7 IF weld fails visual or soap/pressure testing a second time,

THEN do not attempt to make any further repairs. Remove and replace the threaded connection.

END of Instructions

DEFINITIONS

Seal-Weld: Weld metal deposited around a threaded or other mechanical joint and used as a sealant only or thread lock, where the weld metal is not considered to contribute to the strength of the joint.

IMPLEMENTATION RESPONSIBILITIES

NA

GOVERNING DOCUMENT

Utility Standard, TD-4160S, "Welding Control"

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Code of Federal Regulations (CFR) Title 49, Transportation, Part 192—Transportation of Natural and other Gas by Pipeline: Minimum Federal Safety Standards, Section §192.225, "Welding Procedures"

Code of Federal Regulations (CFR) Title 49, Transportation, Part 192—Transportation of Natural and other Gas by Pipeline: Minimum Federal Safety Standards, Section §192.227, "Qualification of Welders"

REFERENCE DOCUMENTS

Developmental References:

American Society of Mechanical Engineers (ASME) B31.8-2010, Chapter II, Welding

Supplemental References:

Engineering Material Specification EMS 4120, "Steel Pipe Material Specification"

Gas Design Standard (GDS) A-15, "Code Numbers for Steel Pipe"

GDS B-10, "Standard Pipe Caps"

GDS B-10.1, "Standard Pipe Plugs"

GDS B-11, "Standard Threaded Pipe Couplings"

GDS B-11.1, "Threaded Reducers (Bell Reducers)"

GDS B-12, "Standard 90° Threaded Elbows"

GDS B-12.2, "Standard 90° Threaded Street Elbows"

GDS B-12.3, "45° Threaded Elbow"

GDS B-13.1, "Extra Heavy Pipe Nipples"

GDS B-13.2, "Threaded One End Pipe Nipples (TOE)"

GDS B-13.3, "Concentric Reducing Nipple (Swage Nipple)"

GDS B-14, "Standard Threaded Tees"

GDS B-14.2, "Reducing Threaded Tee"

GDS B-15, "Standard Threaded Unions"

GDS B-15.1, "Threaded Bushing"

GDS B-23, "Weldolets, Threadolets, and Sockolets"

Utility Procedure TD-4160P-30, "Welder Performance Qualification – 60 psig or Less"

Utility Procedure TD-4160P-31, "Welder Performance Qualification – API 1104 Procedures"

Utility Procedure TD-4160P-32, "Welder Performance Qualification – ASME – Section IX"

Utility Procedure TD-4160P-61, "Visual Weld Inspection for Pipeline Welds"

APPENDICES

NA

Seal-Welding

ATTACHMENTS

NA

DOCUMENT RECISION

NA

DOCUMENT APPROVER

Jerrod Meier, Principal Gas Engineer, Guidance Documents

DOCUMENT OWNER

Don Finkes, Expert Welding Specialist, Gas Guidance Documents/Pipeline

DOCUMENT CONTACT

Don Finkes, Expert Welding Specialist, Gas Guidance Documents/Pipeline

REVISION NOTES

Where?	What Changed?
Entire procedure	This is a new utility procedure.

Steel Bolt-On Saddle Punch Tee

SUMMARY

The purpose of this utility procedure is to support Form TD-4640P-02-F01, "Gas Carrier Pipe Checklist." This utility procedure establishes a uniform method for safely installing a steel mechanical bolt-on saddle punch tee on a natural gas distribution system operating at or below 60 pounds per square inch gauge (psig) in order to identify plastic piping that has been inserted into steel piping prior to welding, cutting, or tapping operations.

This document also provides instructions for permanently welding saddle punch tees that will be left in service on the pipeline.

Level of Use: Reference Use

TARGET AUDIENCE

Maintenance and construction (M&C) personnel qualified to install bolt-on saddle punch tees

SAFETY

Bodily injury may occur if steps in this procedure are not followed. Fitting is pressurized at full line pressure when in use. Read, understand, and adhere to steps carefully. Proper training and periodic review regarding the use of fitting in this procedure is essential to prevent serious bodily injury or equipment damage.

BEFORE YOU START

Ensure bolt-on saddle punch tee is not installed on a steel pipeline with a wall thickness greater than 0.280 inches.

Personnel implementing this procedure must reference and use equipment listed in the gas operations personal protective equipment (PPE) matrix.

Tools and Equipment

The following tools and equipment are required to perform this procedure:

- Fire extinguisher
- Pipe coating removal tools
- Hand wire brush
- Ultrasonic wall thickness tester
- Leak-detection soap solution
- Pipe wrench

Steel Bolt-On Saddle Punch Tee

Before You Start (continued)

- Pipe thread sealant
- 12″ ratchet with 15/16″ socket

  OR

  12″ adjustable smooth-faced wrench

Operator Qualifications (OQ)

This procedure contains covered tasks requiring qualifications. Please consult the Pacific Gas and Electric Company (PG&E or Company) gas qualifications task list, or contact the Gas Qualifications department for covered task information, including date available and effective dates.

TABLE OF CONTENTS

PROCEDURE STEPS

1 Cleaning and Inspection of Steel Pipeline

1.1 IF bolt-on saddle punch tee is used to identify an inserted steel pipeline before any weld operations AND pressure control operations will be performed to depressurize a section of the pipeline,

THEN identify a location where the pipeline will later be depressurized to allow removal of the bolt-on saddle punch tee.

1.2 Remove pipeline coatings around the entire circumference of pipe where the saddle punch tee will be installed, AND clean pipe to bare metal.

1.3 Inspect the area where the bolt-on saddle is to be installed, AND ensure that the O-ring seal is not installed over pits or gouges in the pipe, which may compromise the sealing integrity.

CAUTION

Equipment damage may result if personnel attempt to tap steel pipeline that has a wall thickness greater than 0.280 inches.

NOTE

In the area to be ultrasonically tested, it is recommended to clean steel pipeline to bare metal and to perform multiple ultrasonic tests in various locations to ensure accurate wall thickness measurements.

1.4 Check steel pipeline wall thickness with an ultrasonic tester. Ensure the wall thickness **does not** exceed 0.280 inches. See Figure 1, "Checking Pipeline Wall Thickness."

1. IF wall thickness is found to be greater than 0.280 inches,

   THEN discontinue this procedure and contact engineering personnel.

Figure 1. Checking Pipeline Wall Thickness

2 Fitting Installation

2.1 Inspect bolt-on saddle punch tee for damage to the fitting AND its components.

NOTE

Saddle punch tees sized ¾″ to 1¼″ are hinged on one side and have a single saddle bolt and bolt nut. Fittings sized 2″ to 6″ have two saddle bolts and bolt nuts.

2.2 Remove saddle bolt(s), AND inspect O-ring seal for damage and disbonding from upper saddle.

Steel Bolt-On Saddle Punch Tee

CAUTION

To avoid damage during installation, ensure coupon-retaining punch is fully retracted within tee

2.3 Place saddle in the desired position on the pipe.

2.4 Install saddle bolt(s) onto fitting, AND bolt the nut(s) to saddle bolt(s).

NOTE

A torque wrench (if available) can be used to achieve the 25 to 40 foot-pound torque requirement. If a torque wrench is not available, then the required torque can be achieved using either a 12″ ratchet or 12″ smooth-faced wrench.

2.5 Tighten to between 25 and 40 foot-pounds of torque, taking care not to rotate saddle on the steel pipeline. For saddles with two bolts (2″ to 6″), ensure saddle bolts are tightened evenly.

2.6 IF outlet valve is not pre-installed,

THEN perform the following:

1. Apply pipe thread sealant to the tee's outlet threads.
2. Install approved valve to tee's outlet threads AND tighten. See Figure 2, "Installation of Bolt-On Saddle Punch."

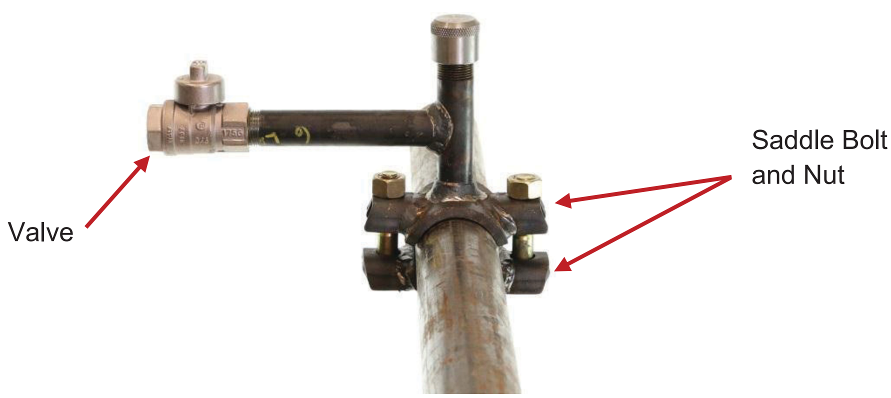

Figure 2. Installation of Bolt-On Saddle Punch

3 Test Requirements

3.1 Remove completion cap AND coupon-retaining punch.

3.2 Inspect coupon-retaining punch to ensure no coupon exists from prior use. See Figure 3, "Coupon-Retaining Punch."

1. IF coupon is found,

   THEN replace with new coupon-retaining punch.

Figure 3. Coupon-Retaining Punch

NOTE
Leak test can be performed using either the tee body or the tee outlet.

3.3 Install test assembly to either tee body or tee outlet. See Figure 4, "Typical Test Assembly Installed."

Figure 4. Typical Test Assembly Installed

3.4 Ensure saddle punch tee has been leak-tested at a minimum of 100 psig (not to exceed 110 psig) for a minimum of 5 minutes prior to tapping operation, per Gas Design Standard (GDS) A-34, "Piping Design and Test Requirements."

3.5 IF leak is identified during leak test,

THEN discontinue use of this procedure and remove saddle punch tee.

4 Tapping

4.1 Ensure saddle punch tee has been leak-tested. Refer to GDS A-34.

4.2 Ensure completion cap AND coupon-retaining punch are removed from saddle punch tee.

NOTE
Coupon-retaining punch is pre-lubricated from the manufacturer. Lubrication may be required if removed by user.

CAUTION
Do NOT add liquid lubricants into tee body. Liquid lubricants can cause hydraulic lock, causing damage to tools and tee. Lubricate coupon-retaining punch using graphite anti-seize lubrication only.

4.3 IF coupon-retaining punch needs lubrication,

THEN lubricate using a graphite anti-seize lubrication.

4.4 Attach coupon-retaining punch into body of service tee and thread clockwise until flush with top of service tee body. See Figure 5, “Installation of Coupon-Retaining Punch.”

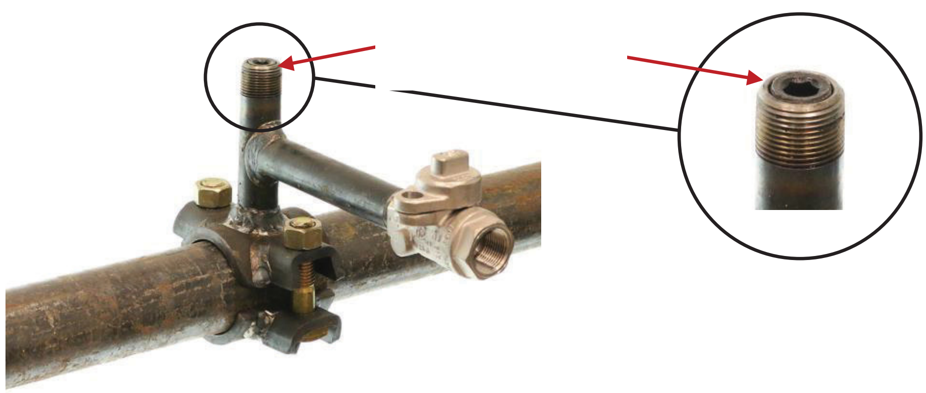

Figure 5. Installation of Coupon-Retaining Punch

Steel Bolt-On Saddle Punch Tee

4.5 Attach tapping tool into hex head of coupon-retaining punch. See Table 1, "Tapping Tool Part Numbers," for part numbers.

Table 1. Tapping Tool Part Numbers

Tapping Tool (Mueller®)	⅜″ – H-18095
Ratchet Handle (Mueller E-4)	83409
Tapping Tool (Continental®)	23-3692-00 (⅜″)
Ratchet Handle (½″ Drive)	12-972 Armstrong

4.6 Attach ratchet handle to tapping tool, AND place operating pin on ratchet handle in clockwise position. See Figure 6, "Mueller Tapping Tool," and Figure 7, "Continental Tapping Tool."

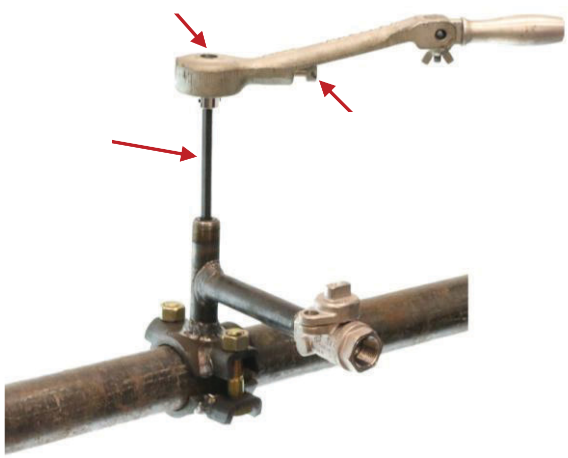

Figure 6. Mueller Tapping Tool

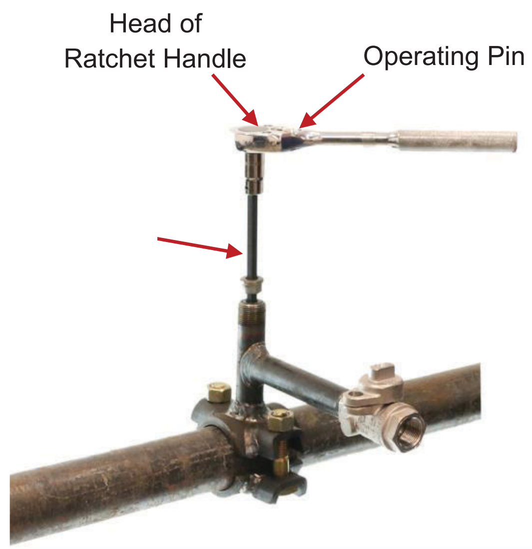

Figure 7. Continental Tapping Tool

4.7 Rotate ratchet handle clockwise until coupon-retaining punch contacts pipe.

NOTE

Torque resistance must be felt during initial tapping operations in order to feel a significant change in torque resistance, which indicates coupon-retaining punch is completely through steel pipe wall.

Steel Bolt-On Saddle Punch Tee

4.8 Tap service tee by supporting head of ratchet with one hand while squarely rotating ratchet handle clockwise with the other hand a maximum of two full rotations to confirm that torque resistance can be felt during tapping operation.

1. IF torque resistance is not felt during initial tapping operations,

   THEN discontinue use of this procedure.

2. IF torque resistance can be felt during initial tapping operations,

   THEN proceed to Step 4.9.

> **NOTE**
>
> A significant change in torque resistance is felt when coupon-retaining punch penetrates the steel pipe wall.

> **CAUTION**
>
> Over-tapping can damage plastic pipe if an insert exists.

4.9 Continue tapping service tee by supporting head of ratchet with one hand while squarely rotating ratchet handle clockwise with the other hand. Once a significant change in torque resistance is felt, indicating coupon-retaining punch is completely through the steel pipe wall, then **STOP**.

4.10 Rotate ratchet handle a **maximum** of two additional full rotations to ensure punch rotates freely and tap is complete.

4.11 Place operating pin on ratchet handle in **counterclockwise** position.

> **WARNING**
>
> Bodily injury may occur if coupon-retaining punch is removed from body of service tee.

4.12 Retract coupon-retaining punch until flush with top of service tee body by rotating ratchet handle **counterclockwise**. See Figure 8, "Retract Coupon-Retaining Punch."

Steel Bolt-On Saddle Punch Tee

Step 4.12 (continued)

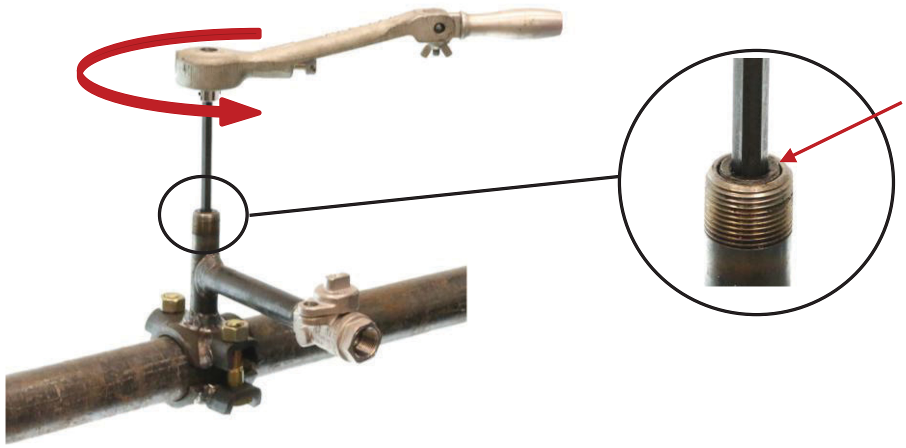

Figure 8. Retract Coupon-Retaining Punch

4.13 Remove tapping tool AND ratchet handle from coupon-retaining punch.

NOTE
Saddle punch tees that are ¾″, 1″, or 1¼″ in size are not weldable and are NOT to be left in service. Saddle punch tees sized 2″ to 6″ are weldable and may be left in service following welding operations.

4.14 IF tapping a ¾″, 1″, or 1¼″ saddle punch tee,

THEN perform the following:

1. Verify line pressure at the fitting outlet.

2. IF line pressure is present,

   THEN perform pressure control operations and proceed to Section 6, "Removal."

3. IF no line pressure is present,

   THEN proceed to Section 6 to remove saddle punch tee.

4.15 IF tapping a 2″ to 6″ saddle punch tee,

THEN perform the following:

1. Verify line pressure at the fitting outlet.

2. IF line pressure is present AND fitting is to be removed following pressure control operations,

   THEN perform pressure control operations and proceed to Section 6.

CAUTION

Prior to tying into a low-pressure system to provide service using the saddle punch tee, contact estimating personnel to ensure the saddle punch tee tap size will be large enough to provide adequate flow.

3. IF line pressure is present AND fitting is to be left in service,

   THEN proceed to Section 5, "Welding."

4. IF no line pressure is present,

   THEN proceed to Section 6 to remove saddle punch tee.

5 Welding

5.1 Attach tapping tool into hex head of coupon-retaining punch.

5.2 Attach ratchet handle to tapping tool, AND place operating pin on ratchet handle in clockwise position.

NOTE

A momentary flow of gas will exhaust through the tee body from the tee outlet.

5.3 Rotate ratchet handle clockwise until coupon-retaining punch contacts pipe, AND tighten firmly to stop the flow of gas through the tap hole.

5.4 Leak-test tee saddle assembly by using leak-detection soap solution to ensure no leakage is present.

5.5 IF leakage is present,

THEN tighten coupon-retaining punch AND repeat Step 5.4.

Steel Bolt-On Saddle Punch Tee

5.6 Remove ratchet handle AND tapping tool from coupon-retaining punch.

5.7 Install completion cap to protect threads during welding process.

5.8 Open valve on outlet connection AND leave in open position.

5.9 Perform saddle welding operations by using approved weld procedure specification (WPS) as follows:

1. Tack-weld top quarter on Side A approximately 1″ as shown in Figure 9, “Tack Weld Side A.”
2. Weld Side B top quarter as shown in Figure 10, “Weld Side B.”
3. Complete Side A top-quarter weld from previous tack weld as shown in Figure 11, “Weld Side A.”

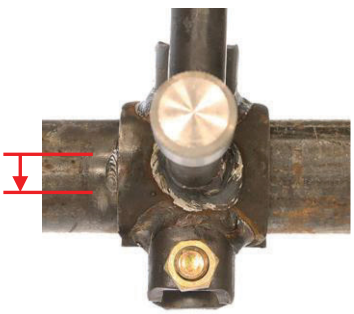

Figure 9. Tack Weld Side A

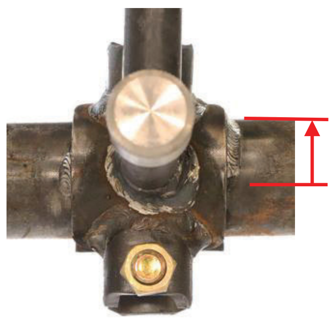

Figure 10. Weld Side B

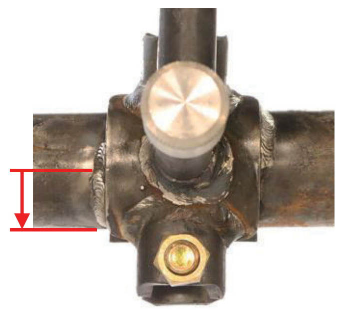

Figure 11. Weld Side A

4. Weld Side B top quarter from previous weld as shown in Figure 12, “Weld Side B.”
5. Weld Side A top quarter from previous weld as shown in Figure 13, “Weld Side A.”

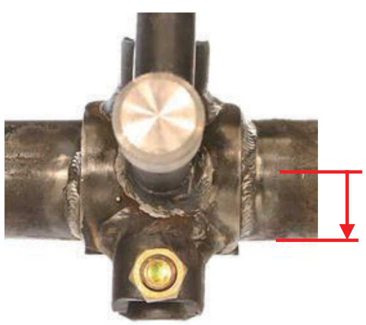

Figure 12. Weld Side B

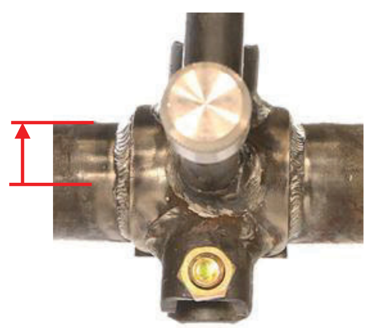

Figure 13. Weld Side A

6. Unbolt and remove under-saddle from pipe.

7. Weld Side C from Side A to Side B as shown in Figure 14, “Weld Side C.”

8. Weld Side D from Side A to Side B as shown in Figure 15, “Weld Side D.”

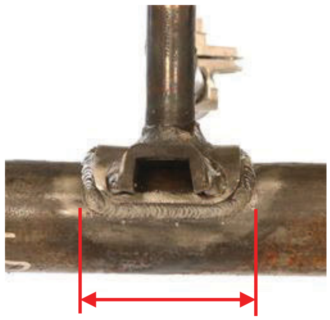

Figure 14. Weld Side C

Figure 15. Weld Side D

9. Complete saddle weld according to TD-4160P-20, “General Welding Requirements,” Appendix 2, Figure 6, “Finished Weld Dimension Details.” See Figure 16, “Complete Saddle Weld.”

Figure 16. Complete Saddle Weld

5.10 Remove outlet valve, AND cut off outlet threads.

5.11 IF saddle punch tee will be used for the service line,

THEN tie in downstream piping by using approved materials for the application.

5.12 IF saddle punch will be abandoned in place,

THEN weld cap to tee outlet.

Steel Bolt-On Saddle Punch Tee

5.13 Allow weld locations to cool.

5.14 Remove completion cap.

5.15 Attach tapping tool into hex head of coupon-retaining punch.

5.16 Attach ratchet handle to tapping tool, AND place operating pin on ratchet handle in **counterclockwise** position.

> **WARNING**
>
> Bodily injury may occur if coupon-retaining punch is removed from body of service tee.

5.17 Rotate ratchet handle and tapping tool **counterclockwise** until coupon-retaining punch is flush with top of service tee body.

5.18 Remove tapping tool AND ratchet handle from coupon-retaining punch.

5.19 Leak-test saddle tee assembly by using leak-detection soap solution.

5.20 Apply pipe thread sealant to outer threads of service tee.

5.21 Attach completion cap AND tighten using pipe wrench.

5.22 Leak-test completion cap by using leak-detection soap solution.

5.23 Refer to GDS E-25, "Field Wrapping With Cold-Applied Tape," and GDS E-35.7, "Application of Coatings to Valves and Components for Buried Transmission Pipelines," for guidance on wrapping. Contact corrosion engineering personnel for any additional guidance on wrapping weld-on style tees.

6 Removal

6.1 Confirm steel piping AND bolt-on saddle punch tee assembly are depressurized.

6.2 Confirm coupon-retaining punch is flush with the top of tee.

6.3 Loosen AND remove saddle bolt(s).

6.4 Remove bolt-on saddle punch tee from steel pipeline.

6.5 Remove coupon-retaining punch from tee, AND replace with new coupon-retaining punch for future reuse of bolt-on saddle punch tee.

6.6 IF plastic pipe is inserted,

THEN remove casing pipe from the section on which the bolt-on tee was installed to confirm that plastic pipe was not damaged during tapping operations.

END of Instructions

DEFINITIONS

NA

IMPLEMENTATION RESPONSIBILITIES

Superintendents and supervisors ensure communication of this utility procedure to gas field personnel.

GOVERNING DOCUMENT

Utility Standard TD-4150S, "Pressure Control for Gas Transmission and Distribution Steel and Cast Iron Pipeline"

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Code of Federal Regulations (CFR) Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Subpart L—Operations

PG&E Gas Operator Qualification Plan

REFERENCE DOCUMENTS

Developmental References:

Gas Design Standard A-34, "Piping Design and Test Requirements"

Gas Design Standard E-25, "Field Wrapping With Cold-Applied Tape"

Gas Design Standard E-35.7, "Application of Coatings to Valves and Components for Buried Transmission Pipelines"

Utility Procedure TD-4160P-20, "General Welding Requirements"

Utility Procedure TD-4170P-52, "Mechanical Fitting Connections for Polyethylene Pipe (Threaded Compression Transitions)"

Utility Procedure TD-4461P-20, "As-Built Process for Distribution Mains and Services"

Utility Procedure TD-4640P-02-F01, "Gas Carrier Pipe Checklist"

Steel Bolt-On Saddle Punch Tee

Reference Documents (continued)

Supplemental References:

NA

APPENDICES

NA

ATTACHMENTS

NA

DOCUMENT RECISION

Utility Procedure TD-4150P-110, “Continental Steel to PE Mechanical Bolt-on Saddle Punch Tee,” Rev. 0, published 03/21/2014

Utility Bulletin TD-4150B-001, “Continental Bolt-On Saddle Punch Tee Tapping Operations”

DOCUMENT APPROVER

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DOCUMENT OWNER

Sal Aminyar, Engineer, Gas Guidance Documents

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Steel Bolt-On Saddle Punch Tee

REVISION NOTES

Where?	What Changed?
Revision 1a	
	• Changed Effective Date from 09/19/2018 to 12/03/2018.
Revision 1	Publication Date: 07/18/2018, Effective Date: 09/19/2018
Title	• Removed “Continental” and “Polyethylene (PE).”
Summary	• Removed PE reference and reference to TD-4150P-109. • Added language for welding.
Before You Start	• Removed tools no longer applicable to procedure.
Section 1	• Clarified when Step 1.1 is necessary.
Section 2	• Added note detailing ¾″ through 1¼″ design and 2″ through 6″ design. • Removed references and guidance related to cathodic protection, wire ring connectors, and PE piping installation to outlet steps. • Updated Figure 2.
Section 3	• Updated title of the section to “Test Requirements” • Added guidance on leak-test requirements • Updated Figure 4.
Section 4	• Removed reference to TD-4150P-109. • Added note to detail that torque resistance must be felt during initial tapping operations. • Added steps for tapping and provided guidance on tap limitations. • Revised Table 1. • Added new Figures 5, 6, 7, 8. • Removed cathodic protection guidance. • Added guidance on sizes of tees that can be welded and permanently left on pipeline. • Added guidance about tying into low-pressure systems.
Section 5	• New section added for welding instructions of weldable punch tees. • Added new Figures 9 through 16.
Section 6	• Added step to remove casing in order to check for potential damage to inserted pipe.

GAS DESIGN STANDARD
PIPE THREAD SEALANTS

B-17

Publication Date: 10/16/2019 **Effective Date:** 01/16/2020 **Rev.** 5

Purpose and Scope

This gas design standard (GDS) provides ordering information for field-applied pipe thread sealants approved for use by Pacific Gas and Electric Company (PG&E or Company).

1 General

1.1. The pipe thread sealants in this document are used to ensure that aboveground threaded connections are gas tight. Do not use these sealants on compression fittings or tees installed in buried plastic systems.

1.2. The pipe thread sealants in this document are approved for field application. Other pipe thread sealants may be approved for use in components supplied by manufacturers, but those sealants are not to be used for field application.

A. Approved pipe thread sealants for manufacturer use are contained in the relevant product documents.

1.3. Follow manufacturer's application instructions.

2 Steel Threaded Connections

2.1. Approved thread sealants for steel threaded connections are listed in Table 1.

Table 1. Company-Approved Pipe Thread Sealants

Description	Preferred Application	Code
Key-Tite Waterproof Pipe Joint Compound, ½ Pint with Brush	0–60 psig[1]	M495001
Rectorseal T Plus 2 Pipe Thread Sealant with PTFE[2], 1 Pint with Brush in Cap	All pressures	M490821

1. Pounds per square inch gauge.
2. Polytetrafluoroethylene.

2.2. PTFE thread sealing tape (described in Table 3) may be used for the secondary seal of pressure control fittings (such as threaded caps of Sav-A-Valve or threaded tee caps). PTFE thread sealing tape may NOT be used on the primary seal of pressure control fittings (such as completion plugs).

3 Stainless Steel Threaded Connections

3.1. Reference the following GDSs for stainless steel fittings:

A. GDS B-13.5, "Stainless Steel Threaded Nipples"

B. GDS B-62, "Stainless Steel Tube Fittings"

C. GDS F-70, "Needle and Instrumentation Valves, Manifolds, and Accessories"

3.2. Multi-Mist Pipe Sealant and Mill-Rose Anti-Seize PTFE Threaded Seal Tape are to be used together and can be installed on the following connections:

- Stainless steel to stainless steel
- Stainless steel to carbon steel

3.3. Approved stainless steel pipe thread sealants are described in Table 2.

Table 2. Company Approved Stainless Steel Pipe Thread Sealants

Description	Application	Code
Multi-Mist Pipe Sealant	Stainless Steel	M490825

3.4. Use the recommended width of tape based on Table 3.

Table 3. PTFE Threaded Sealing Tape

Pipe Diameter	Tape Width	Application	Material Code
Up to 1½"	½" Mill-Rose Anti-Seize PTFE Thread Seal Tape	Stainless Steel / Carbon Steel Pressure Control Fittings	M490822
1¾" to 2"	¾" Wide Mill-Rose Anti-Seize PTFE Thread Seal Tape	Stainless Steel / Carbon Steel Pressure Control Fittings	M490823
Above 2"	1” Wide Mill-Rose Anti-Seize PTFE Thread Seal Tape	Stainless Steel / Carbon Steel Pressure Control Fittings	M490824

3.5. Inspect threads for damage and deformation and ensure threads are clean and free of debris.

3.6. Wrap tape in the direction of the thread, clockwise.

3.7. Wrap tape around male thread, keeping tension so the tape molds itself into the root of the thread.

3.8. Start tape wrap one thread behind the leading edge of the fitting.

3.9. Using only two to three wraps of tape is recommended.

3.10. Apply a thin bead of Multi-Mist Pipe Sealant 360° around the leading thread of the fitting.

3.11. When assembling fittings, ensure that no tape has overlapped the open end of the pipe.

WARNING

PTFE tape fragments getting into the pipeline can cause equipment to malfunction.

3.12. Do not loosen the connection after tightening. If it becomes loosened, replace PTFE tape and sealant.

Target Audience

Personnel involved in procuring or installing pipe thread sealants.

Definitions

NA

Compliance Requirement / Regulatory Commitment

NA

References

NA

Appendices

NA

Attachments

NA

Revision Notes

Revision 5 has the following changes:

1. Added new stainless steel connections section.
2. Added new Multi-Mist Pipe Sealant and Mill-Rose Anti-Seize PTFE Thread Seal Tape products for use with stainless steel threads.
3. Added installation requirements 3.5 through 3.12 for stainless steel threaded connections.

Asset Type: Measurement & Control, Transmission Pipe, Distribution Services, Customer Connected Equipment

Function: Construction

Document Contact: Gas Design Standard Responsibility List

1) BEST PRACTICE ADDRESSED

BP 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.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

Reducing Methane Emissions at Threaded Connections (M2018-001 Phase 2)

Type of program: Basic Research, collaborative project (NYSEARCH)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

The objectives of the project are to: 1) demonstrate the sealing performance of representative threaded connections, and 2) to understand the ability to reduce emissions and to determine the impacts of changing the thread specifications from National Pipe Taper (NPT) to Aeronautical NPT or finding alternatives such as sealants or other best practices to reduce the emissions. Deliverables of this first study would include a report with recommendations regarding what evaluations are necessary to fully quantify the impact of using alternative ANPT standard alone, sealants, or in combination with other alternatives to reduce emissions. Phase 2 objective will further investigate how ANPT dimension compliance is a factor in the quality of a fitting joint.

4) ANTICIPATED OR EXPECTED RESULTS

If successful, the project will provide options to reduce emissions at meter set assemblies threaded connections.

If the project established that leakage rate is substantially reduced by the higher standard of thread specification and testing (ANPT) and new sealants compared to current practices (NPT), then this new standard will be incorporated in utilities' requirements.

5) EMISSIONS IMPACT

This project will shape utilities' preventive strategies to reduce fugitive emissions from threaded connections, meter sets being the most impacted source category. The expected contribution to emissions reduction can be realized once utilities adopt the method deemed by this research to be the most effective approach. For instance, switching to threaded connections with tighter tolerances will likely require a lengthy and phased implementation process which means the resulting emission abatement is achieved gradually.

Assuming a conservative estimate, the savings in 5 years is 10% reduction in meter set emissions, which translates to roughly 60 MMscf per year for PG&E. If successful, this project will also adjust meter set assembly (MSA) emission factor to represent the abatement resulting from a smaller number of leaks and the reduction of the size of the leaks.

6) MILESTONES

Anticipated Start Date: Q4 2019

Anticipated End Date: Q4 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

In this phase 2 project, task 1 will develop a report examining the various thread characteristics and their interactions to identify those interactions that may be the more risk prone for degraded thread engagement. Task 1 will also develop a test plan for comparative leak testing of joints consisting of a) nominal ANPT measurement threads vs b) threads that fail one or more ANPT measurements but meet the NPT thread standard. Task 2 will perform testing. Data collected through the testing of representative fittings will inform utilities of which method(s) or a combination of them will be most effective at reducing emissions from threaded connections.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The total project cost is $42,940 shared among participating NYSEARCH member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

n/a

1) BEST PRACTICE ADDRESSED

BP 23: Minimize Fugitive and Vented Emissions

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. nobleed) or vents significantly less natural gas (i.e. low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

Methane Oxidation Catalysts for Reduction of Emissions in Flaring (M2017-004)

Type of program: Basic Research, collaborative project (NYSEARCH)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

One of the techniques to reduce emissions is to flare methane into carbon dioxide and water. These are typically strict limitations on flaring volumes, especially in urban areas, since the process may produce pollutants such as NO_x, SO_x and large amount of noise. In light of this, Stanford University is looking into an alternative to flaring by catalytically oxidizing methane at lower temperatures. If successful, this technology has the potential to be lower-cost and more accessible alternative to flaring. In Phase 1, the Stanford team performed fundamental scientific research and developed a catalyst that is 10x more reactive than commercially available products. In this phase, they will attempt to raise the reactivity by 2-5x more and build a prototype device.

4) ANTICIPATED OR EXPECTED RESULTS

Depending on the oxidation rate and cost of technology, the eventual use ranges from complete replacement of flaring to a substitute in areas where regulations are very limiting. The application can be used to reduce blowdown and venting emissions from pipelines, process equipment and high bleed components.

5) EMISSIONS IMPACT

Refer to the response in question 4.

6) MILESTONES

Anticipated Start Date: Q1 2019

Anticipated End Date: Q4 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

Phase 2 will leverage research performed during phase 1 which achieved a product 10x more reactive than commercially available catalysts. The team believes there are more optimizations to be made (e.g. pretreatment with steam, active removal of water from active areas, palladium alternatives) to improve the performance and cost-effectiveness of the product.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The total project cost is $238,122 shared among participating NYSEARCH member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

W. Huang, E. D. Goodman, P. Losch, and M. Cargnello. Deconvoluting Transient Water Effects on the Activity of Pd Methane Combustion Catalysts. Ind. Eng. Chem. Res., 2018, 57, 10261-10268.

P. Losch, W. Huang (Co-first author), E. Goodman, C. J. Wrasman, A. Holm, A. Riscoe, J. A. Schwalbe, M. Cargnello. Colloidal nanocrystals for heterogeneous catalysis. Nano Today, 2019,24, 15-27.

W. Huang, A. Johnston-Peck, M. Cargnello, etc. Hydrothermal treatment-induced restructuring of Pd nanoparticles for promoting catalytic activity, in preparation.

W. Huang, M. Cargnello, etc. Enhanced transient activity for methane combustion through in-situ water removal, in preparation.

1) BEST PRACTICE ADDRESSED

BP 23: Minimize Fugitive and Vented Emissions

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.

2) NAME AND TYPE OF RD&D PROJECT OR PROGRAM PILOT

Methane Recovery Purging Gas Pipes into Service (5.19.f)

Type of program: Basic Research, collaborative project (OTD)

3) PROJECT OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

The project objective is to evaluate, enhance, and develop an alternative method to purge gas pipes into service with no or minimal gas vented to the atmospheric. This work will also include an investigation into the economic, environmental, and social impact of this alternative practice. Vacuum purging guidelines will be developed as part of this project effort.

The Distribution Mains and Services asset families have a combined 42,700 miles of pipeline that connects to the gas M&C asset family on the upstream side and transports natural gas to customers throughout the service area. It also includes over 3.4 million service lines that deliver gas from the distribution mains to the assets in the Customer Connected Equipment (CCE) family on the downstream side. The program has a number of replacement projects that will achieve a replacement rate that limits asset age to 100 years by 2030. During this work, it is routine to purge the natural gas to atmosphere from the line. However, this routine process releases potent GHG to the atmosphere..

4) ANTICIPATED OR EXPECTED RESULTS

This project will examine the concept and current practices of using vacuum pumps to purge gas pipes into service, evaluate the vacuum purging process to determine its effectiveness and identify enhancement opportunities, and develop vacuum purging guidelines. In addition, this project will investigate market needs/drivers, potential economic, and environmental impacts.

5) EMISSIONS IMPACT

Gas purging, a process of displacing one gas by another gas, occurs on a routine basis when pipelines are put into and out of service. Pipelines are purged to prevent the presence of a combustible mixture of gas and air. This method results in venting of some natural gas to atmosphere. Through this project, there's a potential to minimize or eliminate the current practice of venting natural gas to atmosphere, thus reducing methane emissions.

6) MILESTONES

Anticipated Start Date: Q3 2019

Anticipated End Date: Q3 2020

Task 1 Project Scoping: Q3 2019

Task 2 Market Drivers and Environmental Impacts: Q1 2020

Task 3 Evaluation of Vacuum Purge System: Q2 2020

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT.

This work will include an investigation into the economic, environmental, and social impact of this alternative practice. The project Examine the concept and current practices of using vacuum pumps to purge gas pipes into service and evaluate the vacuum purging process to determine its effectiveness and identify enhancement opportunities.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

The total project cost is $139,800 shared among participating OTD member utilities.

9) RATE-RECOVERABLE LOADED COSTS SUBMITTTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

In PG&E's 2020 General Rate Case, PG&E had a total forecast of $1.2 million per year for R&D projects that support the 2020 Compliance Plan activities. In addition, PG&E has an adopted forecast of $0.6 million from the 2019 GT&S rate case to support 2020 Compliance Plan activities. Therefore, PG&E has a total forecast of $1.8 million per year for R&D projects embedded in its current cases. There is no need for a specific one-way account.

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

n/a

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 2

CHANGE LOGS FOR PG&E'S ASSET MANAGEMENT PLANS, GAS EMERGENCY RESPONSE PLAN, COMPANY EMERGENCY RESPONSE PLAN, AND GAS SYSTEM OPERATIONS CONTROL ROOM MANAGEMENT

A. Change Log

The following table summarizes revisions since the previous publication of GP-1100: Asset Management Strategy & Objectives, Revision 4, 8/16/2018.

Table 5 – SAMP Change Log

Section	Change	Reason for Change	Implication of Change
1	Moved introduction of Asset Families to Section 2	Keep focus of SAMP Introduction on PG&E's mission and vision.	Clearer focus of PG&E Gas Operation's strategic objectives as they relate to the SAMP
Entire Document	Update references to 2019 documents	Updated content to remain current	Updated
1.1, Fig 1	Replaced TD-4060S with SAFE-10005M	Updated content to reflect changes in GSEMS	Updated
1.2	Section header change to Gas Safety Excellence Management System	Updated term	Greater clarity of current Gas Ops strategic framework
2	Table 1 – Addition of ISO 55001 clauses that correspond to PAS 55 clauses	Better understanding of correlation between PAS 55 and ISO 55001 clauses	Greater clarity in document
2.2	Reordered list of asset families	List reordered to correspond with document numbering order	Greater clarity in document and published GP documents
2.2, Fig 3	Updated figure	Includes Data as an asset family	Updated
2.2, Table 2	Reordered table	Matches numbered list presented earlier in section	Updated
2.4	New section describing the asset management planning process, life cycle phases, and process management framework	Asset management planning process moved from Section 1	Greater clarity of contents of the asset management plan
2.6	Addition of Risk Management subsection	Moved from individual AMPs to the SAMP	Reduce repetition across Asset Management Plan

Section	Change	Reason for Change	Implication of Change
3.1	Addition of subsection	Presentation of AM&SO vision	Clearer focus of PG&E Gas Ops strategic objectives
3.2	Addition of subsection	Presentation of path to achieving excellence in asset management	Greater clarity of current Gas Ops strategic framework
3.3	Addition of subsection on uncertainties in regulator and market conditions relating to gas operations	Acknowledgement of uncertainties in the gas utility industry	Greater relevance to external influences on asset management
Table 3	Addition of GP-2100	Included reference as it is an integral part of Asset Management	Greater clarity of contents of the asset management plan
Table 4	Addition of employee role	Acknowledges all gas operations personnel as having a role in the Gas Safety Excellence and Asset Management	Greater clarity of contents of the asset management plan
5	Added discussion of benchmarking and research & development	Addresses a key area for improvement identified in the 2018 SAMP	Greater clarity of contents of the asset management plan
B	Addition of RISK-5000, TD-4000, and SAFE-10005M	Included reference as they are an integral part of Asset Management	Greater clarity of contents of the asset management plan
C	Tabulation of Gas Asset Management Plan structure	Description of sections in AMPs easier to follow in tabular form	Greater clarity of contents of the asset management plan
D	New Appendix D	Added Figure 4, Gas Operations process management framework table	Greater clarity of contents of the asset management plan
E	Removal of detailed description in asset life cycle definition;	Description included in Section 2.4	Greater clarity of contents of the asset management plan
E	New Table	Added Table 9, List of Acronyms	Greater clarity of contents of the asset management plan

F. Change Log

The following Table 19 summarizes revisions for Rev 6, since the previous publication of GP-1101: Transmission Pipe Asset Management Plan, Revision 5, which was published August 2018.

Table 19. Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Updated statistics, tables and figures	Annual data update	Improved asset knowledge
Section 2	Added section 2.3	Address asset Life Cycle	Added content on asset life cycle
Section 3	Updated	Consistency with other asset management plans	Updated format and content
Section 4	Removed reference to reduce medium risk operations in the system capacity strategic objective	May strategically leverage medium risk operations (portable supply equipment)	None
Section 4	Added table to better display long-term goals	Improved alignment between strategic objectives and long-term goals	None
Section 5	Added sections, added benchmarking and research and development	Improved content	Added sections for readability Added benchmarking Added research and development
Appendix B	Updated	Annual update	Included additional metrics and content on mechanical damage threat.
Appendix C	No change		
Appendix D	Updated	General update	Updated table to align with new life cycle terminology
Appendix E	Moved appendix	Align with strategic asset management plan	Previously Appendix F, aligned with strategic asset management plan guidance
Appendix F	Moved appendix Updated	Align with strategic asset management plan	Previously Appendix G, aligned with strategic asset management plan guidance
Appendix G	Moved appendix	Align with strategic asset management plan	Previously Appendix E, aligned with strategic asset management plan guidance, now a discretionary appendix
Appendix H	Updated	Annual update	None
Appendix I	New	Expanded content	Added content on asset life cycle
Appendix J	New	Expanded content	Added content on Research and Development activities

F. Change Log

The following table summarizes revisions to the publication of the GP-1102: DMS Asset Management Plan, Revision 5, August 2019.

Table 17 - Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Updated tables, figures, and asset inventory information	Updated with current data	Updated information
Section 2.2	Added in book value and pressure system information	Alignment with GP-1101 and improving asset inventory information	Adds information on asset family value
Section 2.3	Added subsection on Asset Life Cycle	Identified as an AMP opportunity for improvement	New subsection added
Section 3	Updated content on risk process and risk register	Transition from the RET Risk Register to an Event-Based Risk Register	None as risk information from 2018 is retained in this AMP
Section 4.1	Modified strategic objective #2 related to legacy cross bore program	New strategic objective reflects the revised scope of the program	Longer completion timeline for this strategic objective because revised scope is larger than original scope
Section 4.1	Added more information to some of the programs and controls	Identified as an AMP opportunity for improvement	Additional information adds clarity to scope of certain programs and controls
Section 5.3	Added subsection on Benchmarking	This addition was a result of the 2019 Management Review session	New subsection added
Section 5.4	Added subsection on Research and Development	Identified as an AMP opportunity for improvement	New subsection added
Appendix G	Added appendix on Asset Life Cycle	Identified as an AMP opportunity for improvement	New appendix added
Appendix H	Added appendix on Research and Development	Identified as an AMP opportunity for improvement	New appendix added

F. Change Log

The following table summarizes revisions since the previous publication of GP-1103: Customer Connected Equipment Asset Management Plan, Revision 5, August 2018.

Table 14 - Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Updated tables, figures, and asset inventory information	Updated with current data	Updated information
Section 2.2	Added in book value	Alignment with GP-1101 and improving asset inventory information	Adds information on asset family value
Section 2.3	Added subsection on Asset Life Cycle	Identified as an AMP opportunity for improvement	New subsection added
Section 3	Updated content on risk process and risk register	Transition from the RET Risk Register to an Event-Based Risk Register	None as risk information from 2018 is retained in this AMP
Section 4	Added content describing link between GP-1102 strategic objective #1 and this AMP	Part of the scope of GP-1102 strategic objective #1 impacts this asset family, specifically as it relates to the Meter Protection Program.	Documents the strategic objective link between GP-1102 and GP-1103 and avoids creating a new and redundant strategic objective for the Meter Protection Program
Section 5.3	Added subsection on Benchmarking	This addition was a result of the 2019 Management Review session	New subsection added
Section 5.4	Added subsection on Research and Development	Identified as an AMP opportunity for improvement	New subsection added
Appendix G	Added appendix on Asset Life Cycle	Identified as an AMP opportunity for improvement	New appendix added
Appendix H	Added appendix on Research and Development	Identified as an AMP opportunity for improvement	New appendix added

F. Change Log

The following table summarizes revisions since the previous publication of GP-1104: Measurement & Control Asset Management Plan, Revision 5, August 2018.

Table 16 – Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Update to previous version of Asset Management Plan dated August 1, 2018	Updated information regarding fleet of M&C assets; areas of progress and continuous improvement associated with M&C assets	Updated information
Section 2.3	Added new subsection on Asset Life Cycle	Identified as an opportunity in AMP improvement	New section added
Section 3	Added introduction to Event Based Risk Register	Transition from RET Risk Register to Event Based Risk Register	Risk information from 2018 retained in AMP
Section 4.1	Revised Strategic Objectives.	Revised strategic objectives to build upon progress achieved in prior year.	Strategic objectives more accurately represent on-going activities and targets
Section 5	Changes and updates to areas of continuous improvement	Updated continuous improvements list to reflect 2018-2019 activities and goals.	Updated information
Sections 5.3 and 5.4	Added new subsections on Benchmarking and Research and Development	Identified as an opportunity in AMP improvement	New sections added
Appendix H	Formerly "Station Condition Health Scoring Criteria"; Now "M&C Asset Life Cycle"	Replaced outdated appendix with more current materials	AMP content more accurately represents current activities
Appendix I	Formerly "M&C Station Condition Health Target Score Criteria"; Now "Obsolescence Management"	Replaced outdated appendix with more current materials	AMP content more accurately represents current activities
Appendix J	New appendix "Underground Holders"	Added to provide clarity around integrity management activities at the Underground Holders	New appendix added
Appendix K	New appendix "Research & Development"	Added to provide descriptions of R&D projects that apply to the M&C asset family	New appendix added
Appendix L	New appendix "Overpressure Elimination Program"	Added in response to request from Risk and Compliance Committee in May 2019	New appendix added

F. Change Log

The following table summarizes revisions since the previous publication of GP-1105: Compression & Processing Asset Management Plan, Revision 5, 8/1/2018.

Table 20 – Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Update to previous version of Asset Management Plan dated August 1, 2018	Updated information regarding fleet of C&P assets; condition of C&P assets; risks associated with C&P assets; mitigations associated with risks to C&P assets; and continuous improvement activities associated with C&P assets	Updated information
Section 2.3	Added new subsection on Asset Life Cycle	Identified as an opportunity in AMP improvement	New section added
Section 3	Added introduction to Event Based Risk Register	Transition from RET Risk Register to Event Based Risk Register	Risk information from 2018 retained in AMP
Section 4.1	Revised Strategic Objectives.	Revised strategic objectives to build upon progress achieved in prior year.	Strategic objectives more accurately represent on-going activities and targets
Section 5	Changes and updates to areas of continuous improvement	Updated continuous improvements list to reflect 2018-2019 activities and goals.	Updated information
Sections 5.3 and 5.4	Added new subsections on Benchmarking and Research and Development	Identified as an opportunity in AMP improvement	New sections added
Appendix H	Updated Compressor Reliability Plan	Updated information based on progress achieved in prior year	Updated information
Appendix I	New appendix “Research & Development”	Added to provide descriptions of R&D projects that apply to the C&P asset family	New appendix added

F Change Log

The following table summarizes revisions since the previous publication of this AMP in 2017.

Table 17 – Changes to the August 2019 Edition

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Updated AF statistics, tables and figures	Annual data update.	Improved asset knowledge and changes in assets
Scn 2.1 and Apdx L	Updated asset list	Annual data update.	Additions to asset inventory
Scn 3	Added new explanation of threat and risk process	Added clarity	Current information.
Scn 4.1	Updated strategic objectives	Updated to reflect revisions made to AF strategic objectives	Current information.
Apdx H	Added life cycle and optimization discussion, and updated life cycle management graphic / plan	Meet the objectives for all AF's of strengthening treatment of life cycle and optimization in this edition. Revised plan since last year.	Current information
Apdx I	Updated with new assets	Added assets	Current information
Apdx K	Added this appendix	Provide context for the AMP.	n/a

F Change Log

The following table summarizes revisions since the previous publication of this AMP in 2018.

Table 17 - Changes to the August 2018 Edition

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Updated AF statistics, tables and figures	Annual data update.	Improved asset knowledge and changes in assets
Scn 2.1 and Apdx L	Updated asset list	Annual data update.	Additions to asset inventory
Scn 3	Added new explanation of threat and risk process	Added clarity	Current information.
Scn 4.1	Updated strategic objectives	Updated to reflect revisions made to AF strategic objectives	Current information.
Apdx H	Added life cycle and optimization discussion, and updated life cycle management graphic / plan	Meet the objectives for all AF's of strengthening treatment of life cycle and optimization in this edition. Revised plan since last year.	Current information
Apdx I	Updated with new assets	Added assets	Current information
Apdx M	Added this appendix	Provide context for the AMP.	n/a

F. Change Log

The following table summarizes revisions since the previous publication of GP-1108: Gas Storage Asset Management Plan, Revision 4, August 2018.

Table 29 - Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
1	Updated last paragraph on regulations	Updated to reflect new DOGGR and PHMSA regulations	None
2 - Table 1	Expanded table to include Life Cycle phase	Provide better understanding of life cycle phase of Storage Assets	
2 - Table 2	Updated for revised operational statistics and added few more	added new fields that are reported to DOGGR	None
2.2.1 Storage Reservoir	Added paragraph on results of recent seismic study for the storage fields	report out on results of study and impact of seismicity on the safety of the storage fields	None
2.2.2 Production Casing Table 6	Revamped table 6 to better reflect test results and asset condition. Added paragraph as introduction to table 6 explaining results and providing context for the information on the table.	Provide relevant information on the condition of the production casing	None
2.2.2 Sand Inspections	Updated analysis discussion and trend chart with current data for sand inspection results	Update data presented	None
2.2.5 Leak Survey	Updated discussion regarding current leak survey practices and findings. Also included highlights of the vapor monitoring plan	Update data presented	None
2.2.6 – Table 11	Updated table to include the Asset Family	To provide clarity on the asset family responsible for the data	None
2.3 – New Section	New section on Life Cycle	GSE requested all AF addressed life cycle in the AMPs	None
3 – Threat and Risks	Updated the Threat and Risks section to describe the current risk management process and the transition to the Event Based Risk Register (EBRR)	To provide an update on the current risk management process	None

Section	Change	Reason for Change	Implication of Change
4	Updated the section on Regulatory and Legislative Impact on Storage Assets	Provide a summary of the new DOGGR regulations and an update on impact of DOGGR final regulations	None
4.2 Programs and Mitigations Overview	Created new table 18 and sections 4.1 and 4.2	summarize the Transmission Pipe and Compression and Processing programs that impact storage assets. New sections to make it easier to distinguish the Storage Programs	None
5.1	New Section - Reformatted section and created table 19	Make it easier to follow Strategic Objectives progress and challenges	None
5.2 Areas for continuous Improvement	Updated table to include Asset Optimization, Supplier Quality, and Process Management	Updated to show key initiatives Storage AF is working on	None
5.3 Benchmarking	New Section added	To illustrate the benchmarking efforts the Storage Family has undertaken	None
5.4 Research and Development	New Section added	Consistency	None

Significant Changes

The updates to the Gas Emergency Response Plan (GERP or Plan) Revision 9.0 focuses on the most significant changes and updates to content since the Plan's inception. Changes include the following items:

- Removal of Chapter 2, Gas Operations Overview to GOKP SharePoint site.
- Addition of NIMS response to Section 2.
- Revision of OEC and GEC response structure in Section 3.

Document Record

This section contains Pacific Gas and Electric Company (Company or PG&E) legal notices and trademarks, as well as provides information related to the ownership and maintenance of this document.

Document Control

Gas Emergency Preparedness (GEP), part of Gas System Operations (GSO), maintains the GERP – Gas Annex to the Company Emergency Response Plan (CERP). This section records the revisions made to the GERP, the responsible persons 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 8, December 31, 2018). For content appearing in Version 8 and removed from this current revision, "(Revision 8)" has been added to the applicable entries. The table lists where the changes occurred, and what changes were made. The effective date is 03/02/2020.

Where?	What Changed?	Who Initiated the Change?
Throughout	Updated department names as needed due to organizational changes.	Various
Throughout	Updated Links as needed.	Various
Throughout	Removed IMT and IMAT terminology.	Mark Rea
1.2	Removed text describing sections of the GERP.	Mark Rea
1.3	Removed section 1.3, providing GERP Gas Annex Overview.	Mark Rea
1.6.3.1	Added section "The Gas Emergency Response Guide."	Mark Rea
1.7.3	Removed Gas Safety and Risk Management Planning. This material can be referred to in a standalone document in GEP Sharepoint GOKP.	Mark Rea
1.7.3.1	Removed Table 1.4 Incident Response Planning Documents. These have been moved with the Response Aids to the GEP Sharepoint GOKP.	Mark Rea
1.7.4	Removed Section 1.7.4 Hazard-specific	Mark Rea

Where?	What Changed?	Who Initiated the Change?
	Incident Planning.	
2	The Gas Operations overview that was a large part of the previous edition, has been removed or if relevant to emergency response, has been moved to the GEP Sharepoint GOKP. This was done to focus the Plan on emergency response.	GEP
2	Entered text throughout to clarify incident command remaining with the ICP, which may change locations.	Mark Rea
2.1.1.	Added section 2.1.1, "Tiered and Flexible Emergency Response."	Mark Rea
2.6.1	Amended language to make use of ICS Form 201- Incident Briefing, for local response activities.	Mark Rea
3	Entered text throughout to clarify incident command remaining with the ICP, which may change locations.	Mark Rea
3.1.2	In Table 3.1, changed language in header from "Triggers" to "Considerations."	Mark Rea
3.2.1.3.1	Removed 3.2.1.3.1 Gas Service Representatives (GSR).	Mark Rea
3.2.1.3.2	Removed 3.2.1.3.2 Gas Transmission Operations and Maintenance (GTO&M).	Mark Rea
3.2.1.3.3	Removed 3.2.1.3.3 General Construction.	Mark Rea
3.2.1.4	Removed PG&E Incident Investigation Team.	Mark Rea
3.2.3.2.3	Moved 2.3.5 Gas Storage Facilities information to Damage Assessment (section 3). Included new optical gas monitoring video sharing process.	Mark Rea Erik Moyer
3.2.4.3.5	Amended language for use of either ICS 201 or IAP.	Mark Rea

Where?	What Changed?	Who Initiated the Change?
3.2.6.4	Removed 3.2.6.4 Pre-event Notification.	Mark Rea
3.2.6.5	Removed Briefings and Conference Calls.	Mark Rea
3.2.6.6	Removed 3.2.6.6 Available and Pre-arranged Resources.	Mark Rea
3.2.7.2	Removed 3.2.7.2 PG&E Contract Crew Support.	Mark Rea
3.2.7.3	Removed 3.2.7.3 Contracts for Incident Response.	Mark Rea
1.5.2.1	Added 1.5.2.1, The Gas Emergency Response Guide.	Mark Rea
2	Changed Section 2 to cover PG&E National Incident Management System (NIMS) response.	Mark Rea
3	Restructured and edited Section information on Gas Emergency Response with detail on ICP, OEC, GEC, and EOC relationship.	Mark Rea
Appendix A	Added NIMS acronyms to Appendix A, List of Acronyms.	Mark Rea
4.2.2	Added language stating IC can use a series of ICS 201s in lieu of an IAP or events using only local resources.	Mark Rea

Document Preparer

Gas Emergency Preparedness

Document Reviewers

Asset Management & System Operations, Gas System Operations, Gas Emergency Preparedness, and Gas Technical Document Management.

Document Approvers

Name	Position	Date
Christine Cowsert	Senior Director, Asset Management & System Operations	12/31/2019
Dan Menegus	Director, Gas System Operations	12/31/2019
Andy Wells	Manager, Gas Emergency Preparedness	12/31/2019

Document Owner

Name	Position	Date
Christine Cowsert	Vice President, Gas Operations	12/31/2019

Appendix K. Change Record

Changes made to the 2019 plan from the 2018 revision are noted in the table below.

2018	TOC	2019	Type	Change Detail	SME
1.1	Key plan elements	1.1	Added	Included 2017 audit elements	Julei Kim
1.3	PG&E's Vision	1.3	Replaced	Removed quotes and added mission description per "About Us"	Eric Boettcher
1.3	Quotation	1.3	Replaced	Removed last year's quote, replaced with "Conveys our story of growth and success…"	Julei Kim
1.6	Plan Maintenance	1.6	Replaced	Changed "initiatives" to "Business Units".	Chris Snyder
1.5	Document Organization	1.5	Updated	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Julei Kim
1.5.1, 1.6	Plan Maintenance	1.5.1, 1.6	Updated	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Julei Kim
1.6	Business Continuity Standard	1.6	Update	Updated the title to "EMER-1001S Business Continuity and Emergency Operations Plan, Training, Exercise and Critique Standard" to "Business Continuity Management Standard".	Chris Snyder
2.1	Territory Assets	2.1	Updated	Updated the assets section to include non-employee and contractors	Eric Boettcher
2.2	PG&E Organization	2.2	Updated	Updated the organization structure lists	Eric Boettcher
2.2	PG&E Organizational Structure	2.2	Update	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Julei Kim
2.3.1	Electric Distribution Assets	2.3.1	Replaced	Changed to 100,000 circuit miles	JC Mathieson
2.3.1	Electric Transmission Assets	2.3.1		Updated data & footnotes per Substation Asset Management	Karen Schneemann Boris Andino
2.3.1	Electric Operations	2.3.1	Update	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Eszter Tompos
2.3.2	Gas Infrastructure	2.3.2	Update	Updated figures	Mark Rea, Andy Wells

2018	TOC	2019	Type	Change Detail	SME
2.3.3	Power Generation	2.3.3	Updated	Changed 26 to “25 FERC Project Licenses”; 68 to “66 powerhouses”; 109 to “105 generating units”; 171 to “170 dams”; 173 to “168 miles of canals”; Solar Generation to “Solar Photovoltaic Generation”; “Solar Photovoltaic Generation” sub-section rewritten, including change from 2 to “252 megawatts of solar photovoltaic generation”.	Micah Brosnan
2.4	Customers	2.4	Completed	Verified figures	Tamyra Waltz
2.4	Critical Customer	2.4	Update	Updated the definition of Critical Customers in Table 2.2 with current info sheet.	Tamyra Waltz
2.5.1, 2.5.2	EP&R Electric Emergency Management	2.5.1, 2.5.2	Move and Update	Removed "Submits an annual filing to CPUC for G.O. 166" from 2.5.2 bullet list and added to 2.5.1 bullet list "Annually developing and submitting to the CPUC the GO 166 report "	Chris Snyder, Julei Kim
2.5.3	Gas Emergency Preparedness	2.5.3	Update	Removed the bullet "Manges overall business continuity for Gas Operations"	Andy Wells, Mark Rea
2.5.5	Power Generation Emergency Preparedness	2.5.5	Updated	Replaced “Director of Safety, Quality and Standards” with “Director of Engineering”	Micah Brosnan
2.6.1	Corporate Incident Management Council	2.6.1	Replaced	Removed Corporate Security from the CIMC Support Staff	Chris Snyder
2.6.1	Corporate Incident Management Council	2.6.1	Removed	Removed 2016 reorganization merging the CIMC and Operating Executives.	Eric Boettcher
3	Risk Management	3	Updated	Added new language about EP&R’s role in managing for risks	Kathi Berman
3.2.2	Earthquakes and Tsunamis	3.2.2	Updated	Added the NOAA tsunami alert system and additional content	Stu Nishenko
3.3.3	Cybersecurity	3.3.3	Update	Changed "cyber incident" to "cybersecurity incident"	Julei Kim

2018	TOC	2019	Type	Change Detail	SME
3.3.2	Scenario titles	3.3.2	Replace	Updated the name of each scenario based on the USGS published scenarios.	Megan Stanton
3.3.4	Vegetation Management	3.3.4	Replaced	Updated number of dead trees	Becky Johnson, CWSP
3.3.4	CWSP	3.3.4	Removed and replaced	Deleted outdated CWSP graphic entirely; replaced other outdated CWSP graphic with updated version.	Becky Johnson, CWSP
3.3.4	Wildfire-related emergencies	3.2.4.1	Updated	Added section 3.2.4.1 Public Safety Power Shutoff Program.	Eric Boettcher
3.3.4	PSPS	3.2.4.1	Add	Added new PSPS Program section	Tracy Maratukulam, Chris Bartchy, Erin Garvey, Keadjian Associates
3.3.4.1	PSPS	3.2.4.1	Update	PMO #338-Included EOC Activation for all incidents and events (including PSPS).	From Oct Extreme+
3.6.1	Training	3.6.1	Update	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Chris Snyder
3.6.1	Training	3.6.1	Update	Added 'EPRS-9000 – EOC Orientation,' description from 'Available EPRS Training.xlsx,' intro paragraph	Chris Snyder
3.6.1	Training	3.6.1	No action	Learning Governance Committee section - Included the EOC Orientation WBT course as a requirement to EOC on-call personnel	Eric Boettcher
3.6.1	Cybersecurity	3.6.1	Update	Changed "Cyber incidents" to "Cybersecurity Incidents" and changed "Cyber Annex" to "Cybersecurity Annex".	Julei Kim
3.6.2	Exercises	3.6.2	Update	Updated photo	Eric Boettcher
3.6.3	After Action Reports and Improvement Plans	3.6.3	Update	Changed "conducts" to "facilitates".	Chris Snyder

2018	TOC	2019	Type	Change Detail	SME
4.5	Dual Commodity Response	4.5	Added	Added new language "The IC oversees the emergency response of both gas and Electric (or other LOBs) with the creation of specific LOB branches within the Ops Section to manage execution of the commodity response."	Angie Gibson
4.5.1	Criteria for Which Commodity Has Authority	4.5.1	Added	In last sentence, inserted "representative" after "commodity".	Micah Brosnan
4.7	Emergency Financial Guidance	4.7	Update	Added bullet "Develop strategic framework for financing the emergency response and recovery and ensure proper accounting."	Jack Liu
5.1	EOC Command Staff	5.1	Update	Added 'OIC' and 'PSS WSOC Liaison' to Figure 5-1	John Bruckbauer
5.1.1.	EOC Commander	5.1.1	Update	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Eric Boettcher
5.1.4.1 5.1.10, 5.4.7, 6.2.7	PSPS Event (initial cap)	5.1.4.1, 5.1.10, 5.4.7, 6.2.7	Update	Changed "PSPS event" to initial cap "PSPS Event"	Julei Kim
5.1.4.1	Intelligence and Investigation (I&I) Unit for PSPS and/or Wildfire	5.1.4.1	Update	Removed "Leader" after Unit and spelled I&I in first sentence. Also reduced sentence preceding bullets to the "I&I Unit:".	Leah Hughes
5.1.8	Privacy Officer	5.1.8	Added	Removed old language about All Clear ID and added new language about working with Corporate Relations and Experian.	Sahar Oswald
5.1.10	Human Resources Officer	5.1.10	Replaced	Replaced "employee and retiree" with "personnel".	Eric Boettcher
5.1.10	Human Resources Officer	5.1.10	Added	Added bullet Reduced essential functions and HR team response during PSPS events	Eric Boettcher
5.2	Operations Section	5.2	Removed	Removed the Transmission Control Center Liaison position from the org chart. Added the ETEC Lead.	Karen Schneemann

2018	TOC	2019	Type	Change Detail	SME
5.2	Deputy Branch Director	5.2	Added	Added a Deputy Branch Director for the Electric Distribution Operations Branch Director	Angie Gibson
5.2	Aviation under Ops	5.2	Update	Added new Aviation Operations Branch Director under Operations Section	PMO #490
5.2	Vegetation Management	5.2	Replaced org chart	Edits of punctuation, spelling and/or wording to add clarity or correction	Becky Johnson, CWSP
5.3	I&I	Fig 5-6	Replaced	Updated I&I chart to always say 'Cybersecurity Incident'	Kristine Brennan
5.3	I&I	Figure 5-6	Deleted	Removed Field Obs Tech Spec under WSOC Tech Spec	John Bruckbauer
5.2: Fig 5-4	Vegetation Management	Fig 5-4	Replaced	Updated title 'Vegetation Management Branch Director' to 'Vegetation Management Branch Lead'	Chris Snyder
5.2 5.2.2 6.1.5 8.1	Area Command		Replaced	Removed the Regional Emergency Center to Area Command. Added language in 6.1.5 about the 6 electric area commands: Bay Area, North Coast, Sac Valley, Tri Valley, Peninsula South Bay, and South Coast Valley.	Angie Gibson, Ken Kirkpatrick
5.2, 5.3, App C	IT Business Technology Advisor	5.2, 5.3, App C	Removed	Removed the IT Business Tech Advisor from the diagram in 5.3	Norma Ortiz, IT
5.2.2	Vegetation Management	5.2.2	Added	Added description of Veg duties	Becky Johnson, CWSP
5.2.3	Notifying CAISO	5.2.3	Update	Edits of punctuation, spelling and/or wording to add clarity or correction	Karen Schneemann Chris Snyder
5.3	Activating I&I during PSPS	5.3	Update	How the I&I section is activated during PSPS event.	Leah Hughes, Michael Puckett
5.3.1	I&I Section and Phys Security	5.3.1	Update	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Joel Moss
5.3.1	Physical Security	5.3.1	Added	Added "Ensures impacted facilities are protected and secured"	Eric Boettcher
5.4	PSPS	5.4	Added	Added 'WSOC Lead,' 'WSOC Tech Spec' and 'Field Obs Tech Spec' ('Field Observer Technical Specialist')	John Bruckbauer

2018	TOC	2019	Type	Change Detail	SME
5.4	PSPS	5.4	Added	Added PSPS Lead, Technical Specialist, and the OIC to the org chart and description of the position.	Christopher Bartchy
5.4	WSOC	5.4	Added	Addition of WSOC specific position to the P&I Section	Julei Kim
5.5.2.2	Food	5.5.2.2	Update	Edited punctuation, spelling and/or wording to add clarity or correction	Amanda Villar and Alicia Taylor
5.5.3	Support Branch	5.5.3	Update	Edits of punctuation, spelling and/or wording to add clarity or correction	Chris Hagen
5.6.3	Treasury Operations Unit	5.6.3	Update	Removed “immediately” from “…required to immediately respond to the incident” from the first bullet.	Jack Liu
5.6.5	Cost Unit	5.6.5	Update	Added “updated unit costs and assumptions” and “accurate” in the “Ensures that a forecast is being created…” bullet.	Jack Liu
5.6.6	Claims Unit	5.6.5	Update	Deleted “due to delays in our response” at the end of the first bullet.	Jack Liu
6.1.2	Substation and T-line Operations Emergency Center	6.1.2	Replaced	Replaced TLEC and SubEC for STOEC	Karen Schneemann
6.1.6	Gas Emergency Center	6.1.6	Added	Added "as needed" to the first sentence of the section	Andy Wells, Mark Rea
6.1.7	EOC	6.1.7	Updated	Added language from Role of EOC slides	Stacy Sher
6.1.7	EOC	6.1.7	Update	Rewrote last para to show other emergency centers activate first and EOC opens to support them. Also indicated VERC is the new AEOC	Stacy Sher
6.2.2	Control Centers	6.2.2	Update	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Norma Ortiz
6.2.2	Electric Transmission	6.2.2	Removed	Removed IT from reviewer list for section 6.2.2	Norma Ortiz
6.2.3	Gas Control Center	6.2.3	Corrected	Changed section 11.1.5.1 to 10.1.5.1	Kristine Brennan, Julei Kim

2018	TOC	2019	Type	Change Detail	SME
6.2.5	Fairfield Security Control Center	6.2.5	Requested	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Norma Ortiz
6.2.6	SIOC	6.2.6	Requested	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Norma Ortiz
6.2.6	Security Intelligence Operations Center (SIOC)	6.2.6	Update	Added new content describing the SIOC.	David Hayr
6.2.7	RCIOC/FXIO C	6.2.7	Moved	Moved the backup data centers to a footnote from ITCC in Table 6.1.	Norma Ortiz
6.2.7	WSOC	6.2.7	Update	Replaced the opening para and bullets per revisions provided by Eric.	Eric Sutphin
6.3	Support and Coordination Centers	6.3	Update	Replaced "employee and retiree" for "personnel". Added "Process impacted personnel and provide disaster assistance."	Eric Boettcher
6.3	Community Resource Centers	6.3	Added	Added the purpose of CRCs and who authorizes.	Tamyra Waltz
6.4.1	Base Camps	6.4.1	Added	Added bullet "Have on-site HR, EAP, and Academy support when required".	Eric Boettcher
6.4.2	Staging Areas	6.4.2	Update/Add	Edited wording first paragraph and added three bullets.	Chuck Williams
6.4.3	Micro Sites	6.4.3	Update	Edited wording first and second paragraph.	Chuck Williams
7.2	CBOs	7.2	Update	Updated the section to emphasize relationship with the American Red Cross	Jimi Harris
7.4	State Emergency Plan	7.4	Update	Replaced "emergency functions" with "emergency support function"	Eric Boettcher

2018	TOC	2019	Type	Change Detail	SME
7.5	Dept of Homeland Security and Department of Energy	7.5	Update	Included info about the NIPP under DHS. Included the Energy SSP under Department of Energy as it more closely might be related.	Eric Boettcher
8.4	Level 3 Incidents	8.4	Removed	WSOC Manager reports to the WSOC Director. WSOC Director reports to VP Asset and Risk Management, Community Wildfire Safety Program. Removed this bullet in section 8.4 Level 3 Incidents.	Eric Boettcher
8.4	New AREP	8.4	Added	Inserted Figure 8-4 Information Flow between Cal OES and PG&E during emergencies and non-emergencies.	From Oct Extreme+
8.5	Level 4 and 5 Incidents	8.5	Update	Edited punctuation, spelling and/or wording to add clarity or correction	Eric Boettcher
8.6	Triggers and Authorities to Activate Emergency Centers	8.6	Update	Changed "cyber incidents" to "cybersecurity incidents" twice in "ITCC activation authority" row of table, second column.	Julei Kim
8.6, App F	New to CERP	8.6, App F	Added	Referenced the EOC Activation Checklist in section 8.6 and Appendix F.	James Neathery
8.8.2	EOC On Call	8.8.2	Update	Edited punctuation, spelling and/or wording to add clarity or correction	Eric Boettcher
8.1	Establish Command	8.1	Update	Edited punctuation, spelling and/or wording to add clarity or correction	Angie Gibson Chris Snyder
8.11.2	External Notification	8.11.2	Added	The new position which started in Oct 2018 is called the PG&E State Operations Center Liaison.	Eric Boettcher
8.12	Damage Modeling	8.12	Added	Included "can include" to the statement that reads "A significant aspect of emergency planning and response".	Andy Wells Mark Rea
8.12	Damage Modeling	8.12; 8.12.1 -5	Added	Added subsections 8.12.3 Fire Potential Index (FPI), 8.12.4 Outage Producing Wind (OPW), and 8.12.5 Debris Flow Hazard Modeling and Warning.	Scott Strenfel Jeff Bachhuber Chris Madugo Sean Gilleran
9.1	Resource Management	9.1	Update	Removed the 2017 CERP note box. Removed "Directing" from the bulleted list. Removed "…responding to the emergency situation…"	Angie Gibson

2018	TOC	2019	Type	Change Detail	SME
9.1.3	Planning & Intelligence Section Chief	9.1.3	Replaced	Minor edits of punctuation, spelling and/or wording to add clarity or correction	Angie Gibson Dedrick Howard
9.1.4	Moving Resources	9.1.4	Update	Added other commodities ordering authority and managing authority to this table.	Angie Gibson, Chris Snyder, Karen Schneeman
9.1.9	Contracts for Emergency Response	9.1.9	Update	Edited second paragraph.	Chuck Williams
9.2	Outbound MA	9.2	Update	Edited of punctuation, spelling and/or wording to add clarity or correction	Chuck Williams
9.2.8	PG&E's Role in the NRE	9.2.8	Update	Replaced the names with positions.	Eric Boettcher
9.3.1.8, 9.3.1.9, 9.3.1.10	Demobilization Role	9.3.1.8, 9.3.1.9, 9.3.1.10	Update	Removed these sections, moved to Electric Annex	Angie Gibson
9.3.5.3	Demobilization Where Gas Supports Electric	9.3.5.3	Updated	Removed reference to Gas Resource Unit representative.	Andy Wells Mark Rea
9.5	Deployment Order	9.5	Removed	Removed section "Deployment Order" and moved into the Electric Annex	Angie Gibson
9.11.2	External Notification	8.11.2	Replaced	Change "PG&E" to "EP&R"	Chris Snyder
10.2	Executive Communication	10.2	Replaced	Changed Electric Transmission to Electric Operations	Chris Snyder
10.2	Executive Communication	10.2	Update	Changed VP, Electric Distribution to VP Asset and Risk Management, Community Wildfire Safety Program	Julei Kim
10.3.1	Coordination at the CA State Level	10.3.1	Update	Added reference to the PG&E SOC Liaison.	Eric Boettcher
10.3.3	Coordination at Local Level	10.3.3	Updated	Edited punctuation, spelling and/or wording to add clarity or correction	Eric Boettcher Mike Maskarich Kevin Smith

2018	TOC	2019	Type	Change Detail	SME
10.3.4	Coordinating with CBOs and NGOs	10.3.4	Update	Changed "EOC" to "OEC".	Jimi Harris
10.4.2	Respond to email contacts made through website	10.4.2	Update	Edited punctuation, spelling and/or wording to add clarity or correction	Tamyra Waltz
10.4.3	Customer Contact Centers	10.4.3	Update	Updated the contact center business hours	Tamyra Waltz
10.4.3	PG&E Customers	10.4.3	Update	Added hours	Tamyra Waltz
App C	Appendix C Emergency Operations Center	App C	Added	Added Aviation Operations Branch Director to Operations Section.	PMO #490, Julei Kim
App C	EOC Org chart	App C	Update	Updated HRCC section of Org chart	Bill Pate, Eric Boettcher
App E	Position Title	App E	Replaced	Changed "manager" to "director"	Megan Stanton
App E	PSPS	App E	Update	Developed a PSPS Advance Call Agenda	From Oct Extreme+
E.1.1, E.1.2, E.2.5	Appendix E	E.1.1, E.1.2	Update	Changed "cyber incident" to "cybersecurity Incident" at bottom of tables	Julei Kim
App E.2.4	Vegetation Management	App E.2.4	Added	Add Veg to Command Call Agenda	Becky Johnson CWSP
App E.2.7.3	Vegetation Management	App E.2.7.3	Added	Add Veg to EOC Planning Meeting Agenda.	Becky Johnson CWSP
App F	Medical Plan 206	App F	Replaced	Removed "Medical Unit Leader" and added "Corporate Safety".	Brian Ward
App F.2.1	Vegetation Management	App F.2.1	Added	Add Veg to agenda	Becky Johnson CWSP
App G	New AREP	App G	Added	Added the DRAFT SOC Liaison checklist into the EOC Resources section	From Oct Extreme+

2018	TOC	2019	Type	Change Detail	SME
Throughout	Throughout	Throughout	Replaced	Replaced VP of Electric Transmission with VP Asset and Risk Management, Community Wildfire Safety Program	Julei Kim
Throughout	New changes	Throughout	Added	Removed the old yellow arrows and added arrows to new 2019 sections.	Julei Kim
Throughout	EOC Resources SharePoint	Throughout	Replaced	Replaced the old "EOC Resources SharePoint" link for the new "EOC Resources SharePoint" link.	Julei Kim
Throughout	Emergency Management Organization	Throughout	Update	Changed "Incident Commander" to "EOC Commander".	Chris Snyder

Minor Revision Guidance Document Analysis (GDA)
Gas System Operations Control Room Management
TD-4436S, Rev: 8b

1. Document Coordinator:	Dominique Erdozaincy	**2. Date of Request:**	02/20/2019
3. Change Details			
Section/Step	**What to Change/Add/Delete**		
2 (Note) to 2.1	2.1 The following lists the minimum authorities and responsibilities for control room personnel, and may require, with management approval and direction, modification to these authorities and responsibilities to safely operate the gas system. SGSCs and GSCs are the ultimate decision makers to execute operator qualified decisions, during normal, abnormal and emergency operating conditions. This is because their roles and Operator Qualifications require comprehensive system knowledge, situational awareness, gas system operations expertise and engagement with related systems and tools on a regular basis. Proper execution of the gas clearance procedure ensures gas control is involved in approving the sequence of operations. In an emergency operating condition, all PGE employees are empowered to make the situation safe prior to notifying Gas Control. Any of these steps to make safe will be documented as part of the clearance process. *While information and influence can be provided to the SGSCs and GSCs, no one can supersede their authority to execute operator qualified decisions.*		
2.1 to 2.2	2.2 A summary of the roles and responsibilities for affected personnel is provided in the following attachments: 1. Roles and responsibilities for gas control personnel: • Attachment 1, “Responsibilities for Management Personnel in the Gas Control Center Supporting the CRM Plan” • Attachment 2, “Responsibilities of Personnel Outside the Gas Control Center Supporting the CRM Plan”		
4. Reason for the Change			
Main drivers and considerations: This change is a result of the 2017 new PHMSA regulations in 192.631(b)(5) “Roles and Responsibilities” and 192.631(h)(6) “Training”. Per the Minor Revision GDA to TD-4436S Rev8a, we added the original verbiage in TD-4436S to comply with the 2017 regulation and clarifying PHMSA FAQs that were published in January of 2018. Per FAQ H-08, PHMSA’s deadline to implementation roles and responsibilities with associated Team Training was January 23, 2019. The Company met this compliance requirement last month, however while implementing the training, it was discovered that the language regarding roles and responsibilities needs to be clarified immediately to comply with 192.631(b)(5). The language in the Control Room Management Manual Process (Console Specific Roles & Responsibilities) has already been updated and published to the Control Room, but the associated TIL standard does not currently align. This is why an immediate publication is necessary to provide consistency in what is stated in CRM and required by the regulation. **Additional info for leadership awareness:** None			

5. Implementation Plan		
Email communication to affected stakeholders – Alfred Musgrove		
6. Stakeholder Reviewers		
Name	**Department/Role**	**Review Date**
Cheryl Quijano	Document Steward, CRM Process and Training	2/20/2019
Dominique Erdozaincy	Document Coordinator, Standards Engineering	2/20/2019
Alfred Musgrove	Manager, CRM Processes and Training	02/19/2019
Frank Mahoney	Senior Technical Authority, Gas Control Strategy and Support	02/20/2019
Tuesdai Powers	Gas Engineer, Expert, Standards Engineering	03/05/2019
Andy Wenzel	Manager, Gas Control	03/04/2019
Stephen Sass	Process Safety	03/04/2019
Gary Ta	Gas Engineer, Senior, CRM Processes and Training	02/15/2019
Frank Maxwell	Process Owner, Senior Manager, Gas Distribution and Transmission Control	2/15/2019

Schedule & Priority

7. Priority: ☐ **Regular** *(monthly publication)* ☒ **High** *(Publish within 24 hours of EDRS approval)*

Reason (for *High* priority only): The language regarding roles and responsibilities needs to be clarified as a result of the 2017 new PHMSA regulations in 192.631(b)(5) “Roles and Responsibilities” and 192.631(h)(6) “Training”.

8. New Effective Date: 03/22/2019

9. EDRS Sequential ☐ **or Concurrent** ☒

Approvers: Dominique Erdozaincy, Cheryl Quijano, Dan Menegus, Tuesdai Powers

Reviewers (if any): NA

Cc (if any beyond the default): Matt Davidson

10. Minor Revision Request Reviewed By	
Supervisor: Matt Davidson	**Date:** 02/20/2019
11. Proposed Schedule:	
Milestone	**Date** (or NA if not applicable)
Submitted for tech writing	03/04/2019
Pre-EDRS Review	NA
Uploaded to EDRS	03/06/2019
Approved in EDRS	03/07/2019

(Publication date is determined by Priority, entered in #7; effective date is entered in #8)

12. Document Category

☐ **Engineering** ☐ **Construction** ☒ **Maintenance & Operations** ☐ **Emergency/Admin**

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 3

DOCUMENT NUMBER: GP-1109, DATA ASSET

MANAGEMENT PLAN, REV. 1

GP-1109 – Gas Data Asset Management Plan

Gas Plan

Document Number: GP-1109

August, 2019

Asset Family Owner: Vincent Tanguay

Document Approver: Christine Cowsert

Table of Contents

Tables

Figures

1. Introduction

This data asset management plan (AMP) is a first for Gas Operations. The data AMP provides an overview of the data "assets" (essential datasets) currently being used by Gas Operations. It also provides a review of the threats to these assets and efforts underway to manage those threats. In this way, the Gas Data Asset Family treats essential datasets similar to how asset families treat physical assets, such as transmission pipe. This data AMP presents a summary of the still-evolving asset registry, an assessment of asset condition, and an overview of risks to the data.

PG&E Gas Operations has determined that creating an asset family specifically for data is consistent with industry best practice and will provide the appropriate attention and resources to the essential datasets required for the safe and efficient operation of PG&E's gas business. Data should be properly managed to have an appropriate life cycle, generation and disposal considerations, and quality control check points. The Asset Knowledge Management (AKM) group within Gas Operations performed initial benchmarking studies and found that other asset-intensive organizations such as transit authorities and rail companies employ data asset management strategies. The benefits expected by implementing this data management approach include:

- Strategic approach to data management
- Clear accountability for data management and ownership
- Supports Gas Stewardship by:
    - Enabling efficient business decisions
    - Reducing/eliminating duplicative data clean-up efforts and redundant data analyses
    - Prioritizing most impactful data management initiatives
- Optimized asset life cycle decision making
- Enhancements in risk modeling (probabilistic) and quantifying risk reduction
- Ability to streamline data collection efforts, thus reducing burden of data collection on field personnel
- Putting PG&E at the forefront of the utility industry in the United States for data asset management
- Leveraging existing asset management framework

This AMP is consistent with the Strategic Asset Management Plan, GP-1100, which is the guidance document for the development of Gas Operations AMPs. It is also complementary to the AMPs for the other asset families.

In its current form, this document should be considered a work-in-progress; it is not intended to be a complete AMP, but rather to show initial asset information collection efforts and articulate the path forward. It is fully expected that future iterations will improve and complete existing gaps.

2. Asset Inventory, Condition, and Life Cycle

PG&E's data is important for safety, regulatory, legal, and financial reasons. Specifically, the datasets used by Gas Operations assist in the safe and reliable delivery of natural gas by providing useful, reliable information to the business.

High-quality and complete data allows for effective, efficient, and compliant decision-making regarding all aspects of PG&E Gas Operations business. A structured approach to the management of this data can result in managed risk, demonstrated compliance, informed asset investment decisions, and improved organizational sustainability, amongst others. For example, with respect to physical assets, by capturing asset data information and maintaining it for the duration of the asset lifecycle, PG&E can ensure that decisions related to operations and status, maintenance, capital investment, etc. are based on approved and validated information.

2.1. Data Asset Overview

The assets in scope for the Gas Data Asset Family include business essential datasets utilized or created by all groups in PG&E Gas Operations, including the other asset families. Table 1 summarizes the organizational units within Gas Operations whose essential data assets fall within the scope of this AMP.

A definition of business essential data was developed to bound the scope of information to be managed by this framework. The definition of business essential data is:

> Business essential data is data vital to the successful operation of the organization or data that could pose a significant legal, financial, safety, or regulatory risk to the organization if not properly managed.

The data management system is separate from the existing Records & Information Management (RIM) organization, which provides the framework for policy, strategy, and guidance for records and information. A record is any information created, received, and maintained during the course of business to document specific operational actions, commercial transactions, contractual obligations, formal business decisions, legal commitments, or similar. In contrast, the focus of this plan is structured data (i.e., digital) that may be derived or sourced from records. However, due to the close relationship between data, information, and records, the Gas Data Management system will work closely with the RIM organization.

The data asset registry includes a list of business essential datasets within each line of business as well as general asset information. Selected preliminary condition metadata was also gathered alongside the list of business essential datasets. The metrics for this metadata, as well as the development of the registry, are discussed in the following sub-sections.

Table 1. Gas Operations Organizational Units

Gas T&D Operations	• GPOM • Field Services / Locate & Mark South • Field Services / Locate & Mark North • M&C / Leak / Corrosion South • M&C / Leak / Corrosion North • Dispatch & Central Clerical • Compliance Operations
Asset Management and System Operations	• Transmission Integrity Management • Risk, Compliance & Qualifications • Distribution Integrity Management • Facility Integrity Management & Technical Services • Wholesale Marketing & Business Development • Gas System Operations • Integrity Management R&D and Innovation • Regulatory Strategy
Gas T&D Construction	• Gas T&D Construction Management • Gas Transmission Construction • Central Operations Support • Distribution General Construction South • Distribution General Construction North • Quality Control, NDE & Welding • Asset Knowledge Management • Resource Planning
Portfolio Management and Engineering	• Resource Management & Governance, Controls & Technology • Distribution Portfolio Management & Engineering • Lean Capabilities Center • Reservoir Engineering • Transmission Portfolio Management and Engineering • Investment Planning, Order Management & Stewardship • Strategic Planning • Process Improvement
Safety Quality and Contracts Management	• Contract Management & Administration • Process Safety • Gas Quality Management • Gas Field Safety & Compliance • Corrective Action Program • Gas Safety Strategy • Gas Safety Excellence

2.2. Asset Inventory and Condition

The data asset registry is structured such that datasets can be identified and described by a single source of basic asset information. The registry includes descriptive information for each dataset including physical asset family (if applicable) and the business process and mega process it supports. The registry also includes details pertaining to:

- Data asset classification (input/output)
- Data asset location (e.g., SAP, GIS, Shared Drive)
- Data asset creator and owner
- Data asset condition (see Section 3.2)

In contrast to the physical assets overseen by the other asset families, the data assets are not explicitly subdivided into types.

2.2.1. Data Asset Condition Metrics

The data asset registry contains metadata pertaining to (a) data quality; (b) data accessibility; (c) quality of process; (d) process documentation; (e) management of change; (f) existence of acceptance criteria; and (g) existence of a quality control or checking process. Metadata for (a) and (b) was collected for both data asset classifications (input/output); metadata for (c) – (f) was only collected for data outputs.

Criteria have been established to dictate what constitutes “good” in terms of data quality, “poor” in terms of data accessibility, etc. The description of how these metrics are determined, the data sources utilized, and future needs for these metrics is presented in Appendix H. Red, amber, and green statuses are currently leveraged to assess accessibility and quality, however, it is envisioned that the assessment methodology will be improved over time. For example, individual elements such as completeness, accuracy, and timeliness may be considered for each dataset. The condition metadata, similar to the other registry contents, is dynamic and anticipated to change over time. Therefore, the condition metadata is a snapshot of the dataset condition at a specific point in time.

2.2.2. Data Asset Current Condition

As of summer of 2019, the initial population of the data asset register is nearing completion. A summary of datasets currently included in the registry is provided in Table 2. All asset metrics included in Rev. 1 of this AMP should be considered “living” and subject to change.

Table 2. Summary of Assets

Organizational Unit	Number of Essential Datasets Reported by Unit	Dataset Examples
Asset Knowledge Management	118	G4 Notification, Order Tracker, Annual Class-ups
Construction Central Operations Support	83	Dispenser Transaction Count, CNG Station Vandalism
Distribution Integrity Management	81	Aldyl-A Risk Rank, Crossbore Repairs Tracker
Facility Integrity Management & Technical Services	4	GIS Information, Contract Information
Gas Contract Management	7	Accrual Log, Contract Tracker, GR/IR Report
Gas Corrective Action Program	2	CAP Data
Gas Dispatch & Scheduling	20	Customer Records, IR Adjustment
Gas Stewardship Office	7	Wave Tool Performance Snapshot
Gas System Operations	219	152 Report, AMR Usage Data, BTU Values
Gas Transmission Ops & Compliance	19	AB56/956.5 Data, GPS Coordinates
Gas Transmission Portfolio Management and Engineering	16	MAOP Catalog, Field Data Management
Guidance Docs & Eng Services	2	Work List
IM R&D and Innovation	41	Transmission Pipelines – Blowdowns, MSA Systems - All Damages
Integrated Planning Gov Contr & Tech	54	CPA Down Report, RM Plan, ETS Read
Risk, Compliance & Quals	73	GOST Final Answers Log, Master Data Request Tracking Log
Transmission Integrity Management	209	Care Facility Flag, Customer Count, DC Interference Mitigation Work
Wholesale Marketing & Business Development	71	CTA Information, CTA Pipeline Usage File
Work and Resource Planning	10	BOBJ Report, CN24 Report

Altogether, the contributing organizations led to the creation of an asset registry containing 1043 datasets. As shown in Figure 1, Gas System Operations contributed the most datasets (219) to the catalog, closely followed by Transmission Integrity Management (209).

Note that the datasets are not unique. A certain dataset may be classified as an input by multiple lines of business.

Based on data storage location information provided to date by the reporting organizations with Gas Operations, Figure 2 summarizes the top 12 data storage locations across all organizations. For reporting purposes, locations that housed fewer than ten datasets were generically grouped as “other.” Some examples of data storage locations in the “other” category include GasView, RiskFinder, ProntoForms, etc.

Using the definitions outlined in Appendix H, dataset quality was evaluated within each organization. Figure 3 and Figure 4 summarize the dataset quality information collected from selected reporting organizations. Note that these figures report on the quality of both data inputs and outputs within each organization; in the future, it may be valuable to differentiate between inputs and outputs for the purposes of this analysis. While many organizations report 100% "green" quality, these groups have relatively few essential datasets. Organizations with higher numbers of essential datasets showed higher frequency of amber and red statuses. While the desired state of each dataset has yet to be fully defined, it is clear that improved quality would benefit both the individual lines of business and PG&E as a whole.

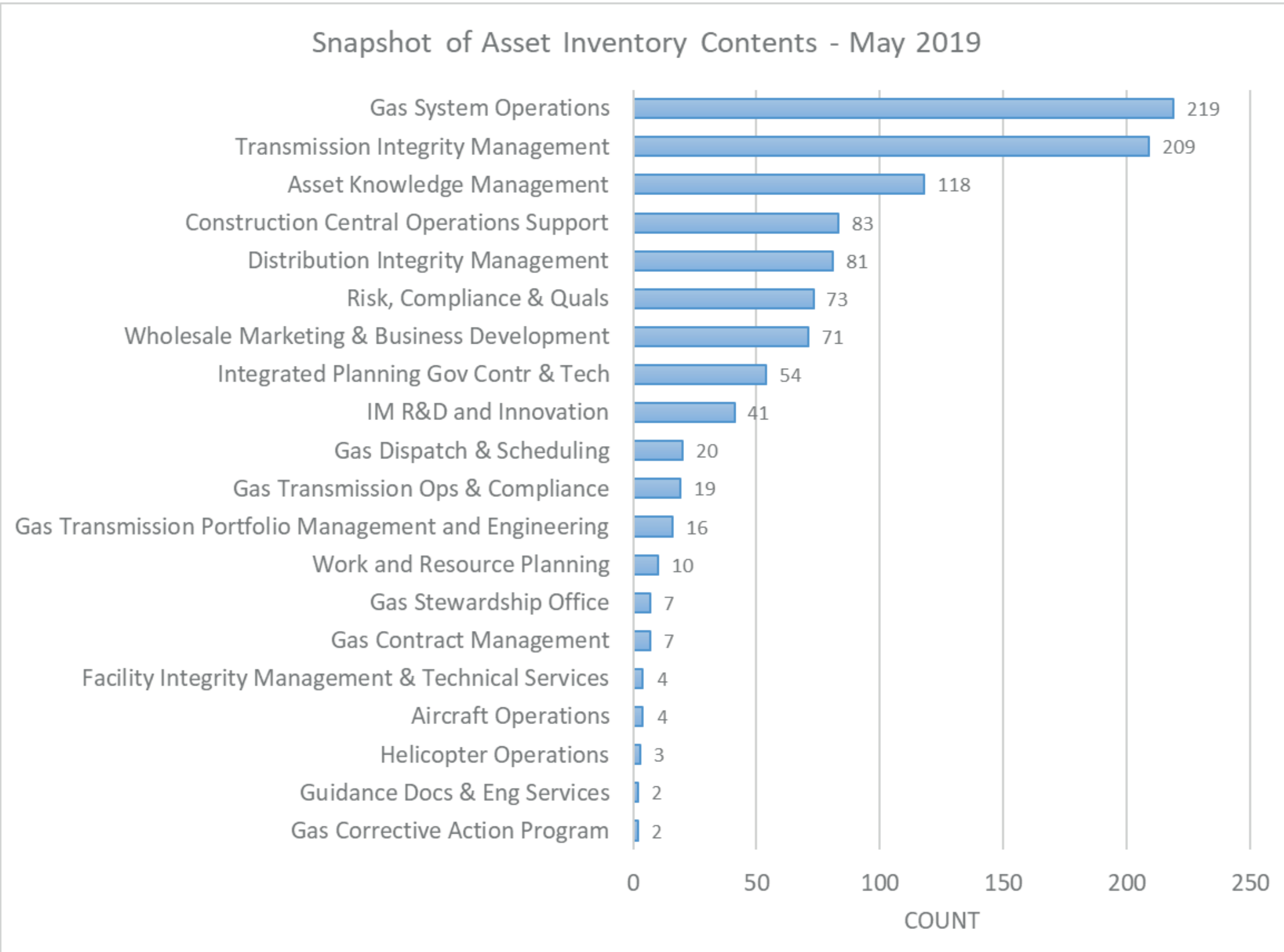

Figure 1. Summary of business essential datasets reported by organizations with Gas as of May 2019.

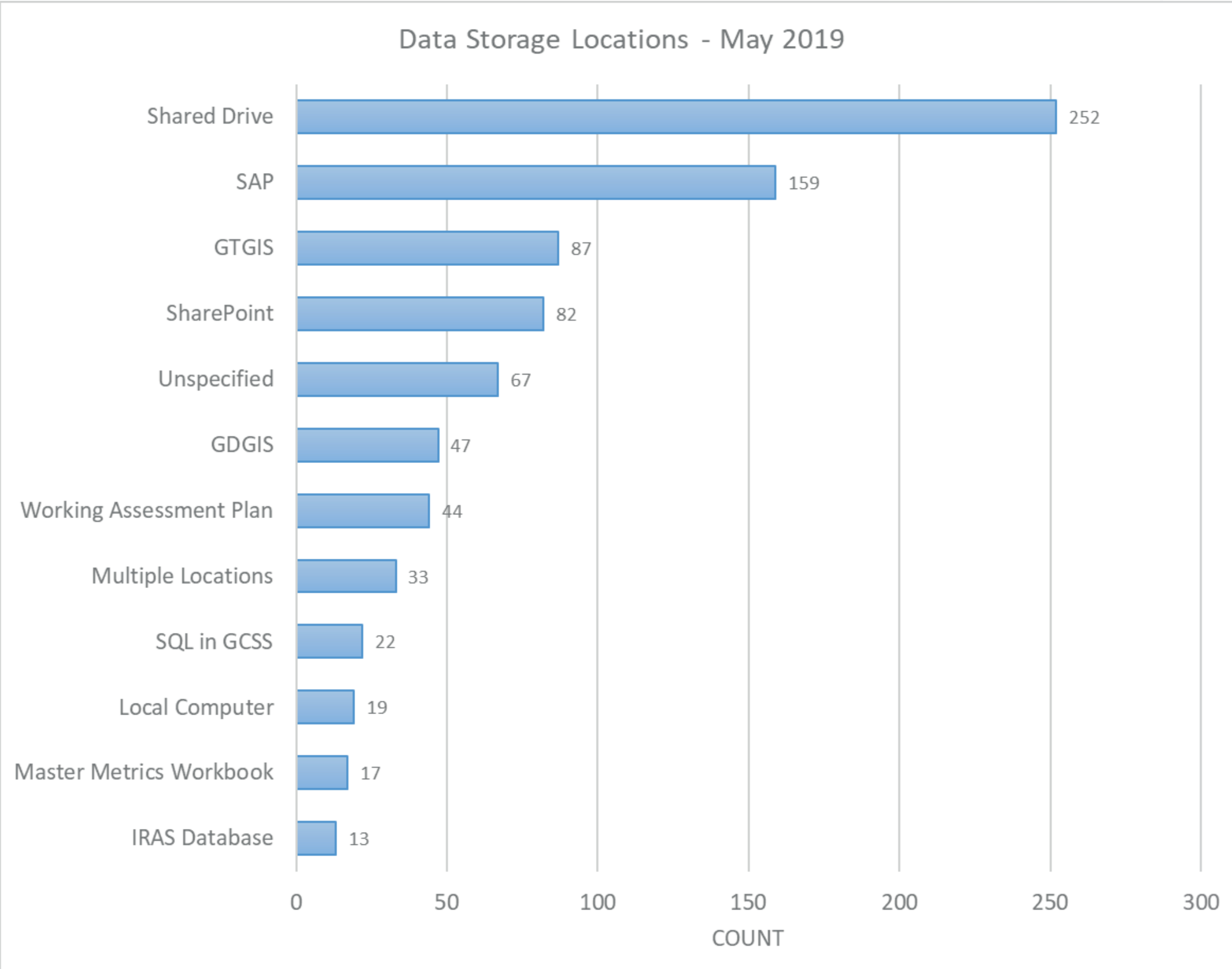

Figure 2. Summary of top data storage locations across all reporting Gas Operations organizations as of May 2019. Some storage locations were not provided, represented by the "unspecified" category.

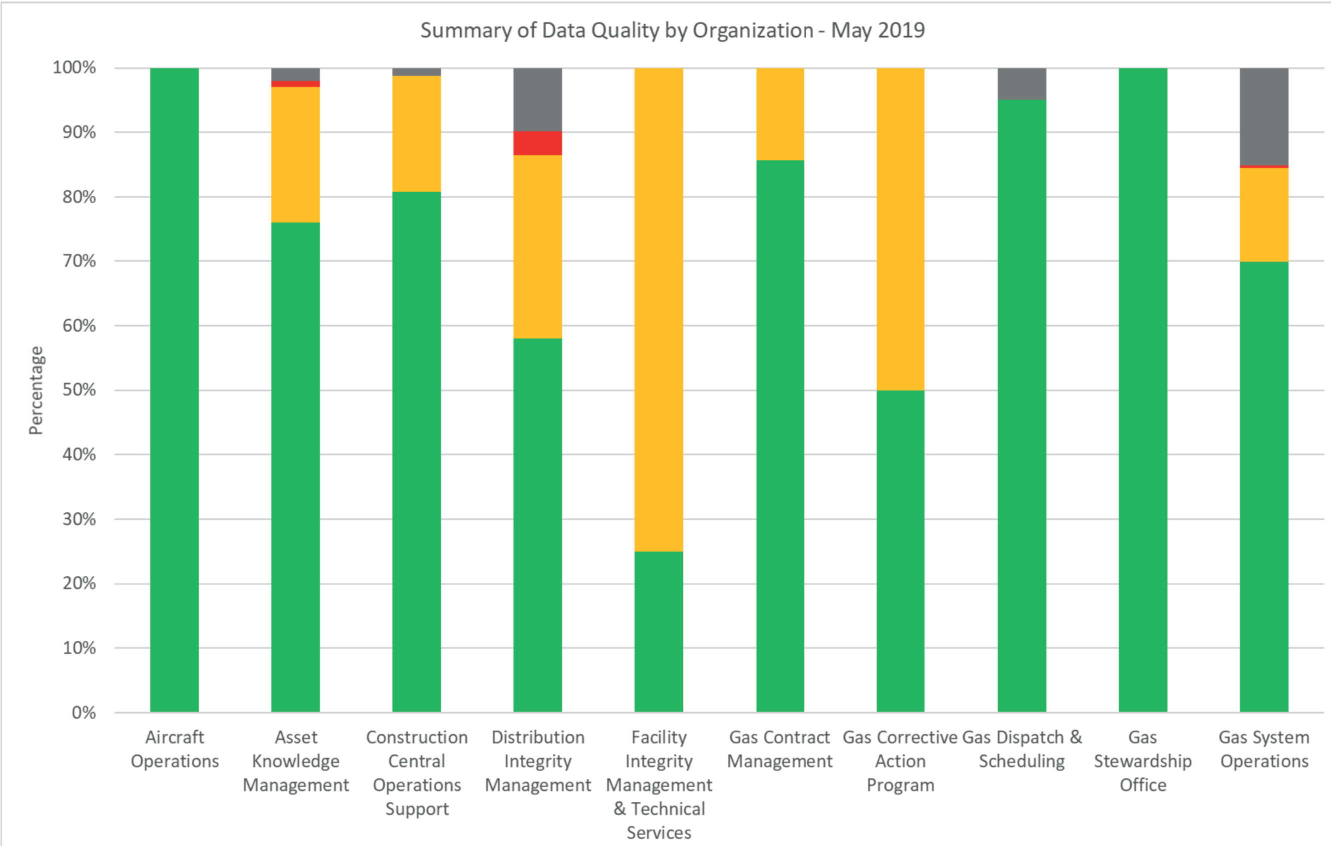

Figure 3. **Summary of data quality by organization. Bars are color-coded to correlate with "red", "amber", "green", and "unknown" (grey) status values.**

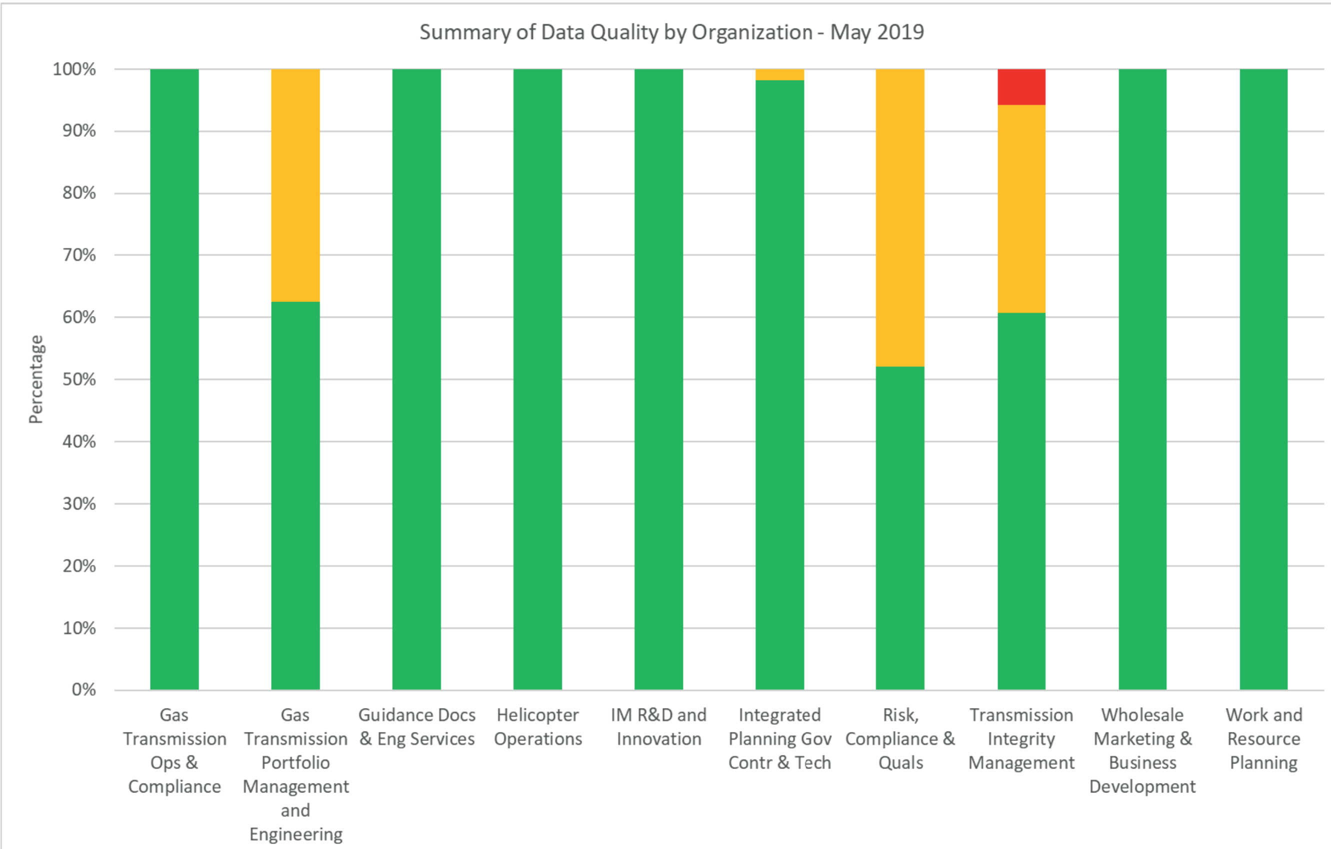

Figure 4. Summary of data quality by organization (continued). Bars are color-coded to correlate with "red", "amber", "green", and "unknown" (grey) status values.

2.3. Asset Life Cycle

The same asset life cycle principles that apply to physical assets can also be applied to data. Life cycle and optimization for Gas Operations assets are introduced in GP-1100. As an extension of this, this AMP provides an introduction to asset life cycle as it pertains to data. The processes and approaches used to manage assets at each stage of the asset lifecycle are shown in Figure 5. These include: the plan/design phase, the build/acquire phase, the operate/maintain phase, and the retire phase.

Consideration of all stages of asset life cycle will be a critical component of effective data management, and these principles will be incorporated into the forthcoming data governance standards as the gas data asset family continues to mature.

Figure 5 Life cycle phases.

3. Threats and Risks

Risk is defined as the potential for an adverse event that can impact the company's ability to achieve its objectives. Risk drivers are defined as factors that could cause risk to occur. In this way, data can be thought of as a risk driver, as data can be a significant factor in the likelihood for a risk to occur. It is envisioned that a two-fold approach will be utilized to understand the threats and risks to data in Gas Operations.

The first approach will be a "top-down" view that aims to understand high-level threats to data. This approach will be similar to the risks and threats identified by other asset families in their respective AMPs. It is envisioned that these threats will be tracked in the Risk Register, which is a central repository where risk names and descriptions are documented along with other pertinent information. Tracking the data threats in the Risk Register will also allow them to be compared to other enterprise risks, including those to physical assets. The following provides a brief summary of this process.

PG&E utilizes an Enterprise and Operational Risk Management (EORM) framework to manage risks at both an enterprise and operational level[1]. PG&E's Gas Operations has also adopted a risk management framework to provide a repeatable and consistent method to identify, assess, rank, and mitigate risk across its asset families.

Through 2018, the Risk Evaluation Tool (RET) served as the Risk Register[2] and it was used to document, evaluate, and assess asset-related risks for Gas Operations. RET scores for individual risks were updated in the Risk Register through an annual risk refresh process which included calibration sessions both within and between asset families prior to calibration at the enterprise level. For the purposes of assessing risks through the EORM framework, these individual Gas Operations risks were consolidated into "roll-up risks"[3] that were defined solely by the risk event as opposed to both the risk event and its risk driver.

Although the exact manner in which data risks will be integrated into the EORM and Integrated Planning Process (IPP) is not well-defined at present, the vision is to include data risks in 2020 risk assessment process. In addition to the high-level, "top-down" view, data risks will also be assessed utilizing a framework similar to that of Integrity Management. This approach will be granular in nature and assess the risk associated with datasets within the different organizational units in Gas Operations. By assessing the risk associated with individual datasets, a prioritization scheme may be developed, allowing for effective use of resources in mitigation efforts.

[1] See RISK-5001S, Enterprise and Operational Risk Management Standard, and RISK-5001P-01, Enterprise and Operational Risk Management Procedure, for additional information.
[2] Definition of Risk Register consistent with TD-4011S (Revision 2), Gas Operations Asset Management System Risk Management.
[3] Within any given "roll-up risk" was a "representative risk," which was defined as the risk with the highest score within that "roll-up risk."

3.1. Threat and Risk Identification

Examples of selected high-level risks to data are included in bulleted form below. This list contains possible examples and will be refined as the Gas Data Management Program matures. It should be noted that some data risks may be current, while others may be historical (and static) in nature. Current data risks are those wherein existing processes are either creating data of poor quality or modifying data in a manner inconsistent with best practice. Historical data risks are a result of processes that are not currently being perpetuated, but have resulted from prior processes or actions.

In addition to the list of threats provided below, benchmarking will be performed to understand specific data threats considered by others in the natural gas industry and other relevant industries discussed further in Section 5.3. It is likely that the outlined threats and risks may be combined into a single "roll-up" risk driver for the Integrated Planning Process.

<u>Examples of high-level data threats and associated risk</u>

- Inadequate / ineffective data input
- Inadequate / ineffective data maintenance
- Lack of data ownership / stewardship
- Lack of clearly defined source of record
- Lack of consensus regarding data quality

Inadequate data management resulting in an operational incident and/or adverse business result, including any potential negative impacts occurring after the event itself.

3.2. Integrity Management Approach

To supplement the high-level view of data threats, risk may be evaluated on a granular level for specific datasets. This approach is analogous to the Integrity Management Program framework, wherein each asset is evaluated in a detailed manner to determine risk. This detailed approach offers many advantages, including the ability to prioritize those assets (datasets) with the most need. However, one disadvantage is that risk is not evaluated in a manner consistent with the RET so that it can be compared to other enterprise risks. In this way, the Integrity Management Program approach is useful for prioritization of work within the Asset Family, but less useful for comparison of risk to other asset families.

Development of this detailed approach for data is underway; a short summary of the effort is provided here. As a part of the data asset registry currently being compiled, selected metadata is being captured regarding the condition of the datasets, as described in Section 2 of this AMP. To assess risk of each dataset, both likelihood and consequence are considered. For data, "likelihood" takes the form of data quality and accessibility. If essential datasets are of poor quality and/or inaccessible to those who need them, the likelihood of a data risk event increases.

For data assets, relative likelihood values have been developed based on dataset quality and accessibility RAG (red, amber, green) status values. As the program matures, accessibility and quality may be further refined by considering individual elements which may include completeness, accuracy, and timeliness. In contrast, relative consequence values are based on the business process risk. A mathematical relationship was developed to arrive at a relative risk ranking by combining both likelihood and consequence. This outlined methodology may be refined through the course of technical conversations with subject matter experts (SMEs), asset family owners (AFOs), data experts, and other PG&E leadership.

As the program matures, the Gas Data Asset Family at PG&E will explore the extent to which this detailed Integrity Management Program approach may be combined with the higher level threat analysis and RET.

4. Desired State, Strategic Objectives, Programs and Risk Mitigations

The long-term vision for the Gas Data Asset Family is to improve the overall functioning of PG&E Gas Operations by highlighting the importance of high-quality data for effective decision making and operation of a safe, affordable, reliable gas company. The target is for PG&E Gas Operations to have valuable data, managed with purpose. Goals supporting this vision include:

- Improved data quality and accessibility over time via increased focus and visibility on data-related work.
- Improved focus and culture of PG&E employees on the importance of data.
- Minimized risk / optimized risk reduction per dollar of spend

The Gas Data Asset Family's strategic objectives are developed in support of the long-term goal to maintain and improve asset condition and mitigate risks and threats. These strategic objectives also support PG&E's Line of Sight (LoS) goals and its corporate mission to safely and reliably deliver affordable and clean energy to its customers and communities every day, while building the energy network of tomorrow.

Table 3. Strategic Objectives Mapped to Gas Operations Line of Sight Goals

Gas Operations Goals	Strategic Objectives	Metrics
Safe / Compliance / Affordable	1. Develop an AMP for data in Gas Ops by end of 2019	• Completed • Percent implementation
Safe / Compliance / Affordable	2. Develop an asset register with essential datasets and pertinent metadata including the quality, condition, and location of the datasets by end of 2019 Operationalize by end of 2020	• Completed draft • Percent operationalization
Safe / Compliance	3. Develop a framework to assess risk for Gas Ops data by end of 2020	• Ensure data is represented in the risk register for the IPP

Gas Operations Goals	Strategic Objectives	Metrics
Safe / Compliance / Affordable	4. Develop data governance document including clearly defined data owners, stewards, and systems of record by end of 2020	• Data governance document completion and implementation
Safe / Compliance / Affordable	5. Improve completeness and accuracy of digital data to support data-driven risk management and work prioritization by 2022	• Data quality
Safe / Compliance / Affordable	6. Creating all required data asset-related standards and procedures, including a data standard and data dictionary, by 2023	• Completed draft • Percent operationalization

Gas Data Asset Management Maturity Model

Similar to other asset families, the Gas Data Asset Family intends to develop a maturity model to track program development. Initial work is currently being conducted to determine appropriate milestones and aggressive but realistic timeframes for each milestone. Future iterations of this AMP will contain these milestones tracked as a maturity model enabling visibility and transparency into the development of the program. Important milestones in the data management program development overlap with selected strategic objectives and are listed below:

1. Develop an asset register with essential datasets and pertinent metadata including the quality, condition, and location of the datasets.
2. Develop a data standard.
3. Develop a data dictionary.
4. Develop a data taxonomy standard.
5. Refine quality metrics to provide additional insight into the strengths and opportunities for particular datasets (completeness, accuracy, timeliness).
6. Implement an appropriate software package for management of this data (Collibra).
7. Clearly define data owners and data stewards for all essential datasets.
8. Clearly define systems of record.
9. Where appropriate, consolidate the number of data storage locations. Eliminate instances of essential datasets stored offline.
10. Develop a framework to assess risk in datasets.

Gas Data Management Strategic Objectives

The long-term vision for data management in Gas Operations is to improve the overall effectiveness and efficiency of the data that will enable better decision-making and improved safety and reliability. The Gas Operations objectives are as follows:

- Safe
- Affordable
- Compliance
- Reliable
- Customer
- People

Initial strategic objectives for the Gas Data Asset Family have been identified, as summarized in Table 3, and include:

1. Developing an Asset Management Plan for data in Gas Ops
2. Developing an asset register with essential datasets and pertinent metadata including the quality, condition, and location of the datasets
3. Developing a framework to assess risk for Gas Ops data
4. Developing data governance document including clearly defined data owners, stewards, and systems of record
5. Improving completeness and accuracy of digital data to support data-driven risk management and work prioritization by 2022

6. Creating all required data asset-related standards and procedures, including a data standard and data dictionary, by 2023

4.1. Strategic Objectives, Programs and Mitigations Alignment

Once the program matures, the Gas Data Asset Family will have specific programs and mitigations that target the defined strategic objectives. This section of the AMP will map each program to one or more of the strategic objectives.

4.2. Control and Mitigation Programs

Meeting the defined tactical goals will improve the data quality in Gas Operations to assist in decision making, risk reduction, and help drive PG&E's Gas Operations to be the "safest and most reliable, affordable, and clean energy company in the United States". Further revisions of this AMP will include a description of threat and risk-mitigating programs.

5. Areas of Progress and Continuous Improvement

The Gas Data Asset Family will continue to mature and build out the AMP with clearly-identified threats, risks, mitigations, and strategic objectives. A framework to assess risk will be developed and essential datasets will be evaluated utilizing the risk assessment framework. In this way, the AMP for data will continue to develop over the next few years. However, in addition to the expected path ahead, the Gas Data Asset Family intends to identify areas of opportunity for improvement throughout the course of the program, to be articulated in future iterations of this AMP.

5.1 Strategic Objective Progress and Challenges

Since its inception in late 2018 / early 2019, the Gas Data Asset Family has made progress toward achieving the identified strategic goals. Specifically, in the recent months, the Gas Data Asset Family has:

- Developed and published the first iteration of the Data Asset Management Plan
- Initiated development of the Gas Data Asset Register (~70% complete)

As the program matures, this section will highlight progress and challenges as they relate to the defined strategic goals.

5.2 Areas for Continuous Improvement

In this section, areas of progress and continuous improvement that do not fall directly in-line with the defined strategic objectives will be documented.

5.3 Benchmarking

Benchmarking is an important activity to understand how PG&E programs and performance compare with industry peers and to identify best practices which contribute to the continuous improvement journey for this asset family. Benchmarking is particularly important for the Gas Data Asset Family, as leveraging learnings from other utilities and companies will be critical to further the development of the data program at PG&E. While PG&E continuously participates in benchmarking activities which are valuable to the Gas Data Asset Family, the integration and implementation of benchmark learnings could be improved. Recently, Gas Operations introduced a pilot process to more formally and centrally collect best practice and benchmark information. If successful, this process could enable ease of access and broad sharing of benchmarking information across the gas business leading to improvements in the Gas Data AMP.

Appendices

Appendix	Title
A	Related Documents
B	Threat Matrix and Key Threats
C	Asset Family Risks
D	Stakeholder Roles and Responsibilities Matrix
E	Summary of Integrated Programs
F	Glossary of Acronyms and Abbreviations
G	Change Log
H	Dataset Condition Metric

A. Related Documents

The following table lists documents associated with this AMP.

Table 4. Related Documents

Related Document	Document Number / Description	Location
Enterprise and Operational Risk Management Standard and Procedures	RISK-5001S, RISK-5001P-01, RISK-5001P-02, RISK-5001P-03	Guidance Document Library – Risk and Compliance Management – RISK
Gas Safety Excellence	TD-01	Technical Information Library
Gas Operations Asset Management System Risk Management Standard	TD-4011S	Technical Information Library
Strategic Asset Management Plan	GP-1100	Technical Information Library
Strategic Risk Management Plan	GP-2100	
Transmission Asset Management Plan	GP-1101	
Distribution Mains and Services Asset Management Plan	GP-1102	
Customer Connected Equipment Asset Management Plan	GP-1103	
Measurement & Control Asset Management Plan	GP-1104	
Compression and Processing Asset Management Plan	GP-1105	
LNG/CNG Portable Supply Asset Management Plan	GP-1106	
CNG Station Asset Management Plan	GP-1107	
Gas Storage Asset Management Plan	GP-1108	

B. Threat Matrix and Key Threats

As the Gas Data Asset Family matures, this appendix will be developed and present the threat matrix for Data within Gas Ops.

C. Asset Family Risks

Once defined for the Gas Data Asset Family, this appendix will list the risks from Session D in tabular format.

D. Stakeholder Roles and Responsibilities Matrix

As the Gas Data Asset Family matures, this section will be added to describe roles and responsibilities relevant to the data within Gas Ops and the Gas Data Asset Family.

E. Summary of Integrated Programs

As the Gas Data Asset Family matures, this section will describe work that is relevant to other AMPs.

F. Glossary of Acronyms and Abbreviations

The following is a glossary of acronyms and abbreviations used in this AMP and related documents.

Table 5. Acronyms and Abbreviations

Acronym	Meaning
AC	Atmospheric Corrosion
AF	Asset Family
AFO	Asset Family Owner
AMP	Asset Management Plan
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CCE	Customer Connection Equipment
CCR	California Code of Regulations
CFR	Code of Federal Regulations
CNG	Compressed Natural Gas
CoF	Consequence of Failure
CP	Cathodic Protection
CPUC	California Public Utilities Commission
DIMP	Distribution Integrity Management Program
DOT	Department of Transportation
ECDA	External Corrosion Direct Assessment
EORM	Enterprise Operations Risk Management
ERM	Enterprise Risk Management
FIMP	Facility Integrity Management Program
GIS	Geographic Information System
GPOM	Gas Pipeline Operations & Maintenance
GPRP	Gas Pipeline Replacement Program
GRC	General Rate Case
GT	Gas Transmission
GTI	Gas Technology Institute
GT&S	Gas Transmission and Storage
HAZOP	Hazard Operability
HCA	High Consequence Area
HPR	High Pressure Regulator
IC	Internal Corrosion
ICDA	Internal Corrosion Direct Assessment
ILI	In-Line Inspection
IM	Integrity Management
INGAA	Interstate Natural Gas Association of America
IT	Information Technology
LNG	Liquefied Natural Gas
LOB	Line of Business
LoF	Likelihood of Failure
LoS	Line of Sight
LVC	Large Volume Customer
M&C	Measurement and Control
MAOP	Maximum Allowable Operating Pressure
NDE	Non-Destructive Examination
OSHA	Occupational Safety and Health Administration
P&ID	Piping and Instrumentation Diagram
PAS55 / ISO 55001	Publically Available Specification 55 / International Standards Organization 55001
PG&E	Pacific Gas and Electric
PHA	Process Hazard Analysis
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIR	Potential Impact Radius
PRCI	Pipeline Research Council International
PSEP	Pipeline Safety Enhancement Plan
psig	Pounds per Square Inch Gage
PSRS	Project Status Reporting System
RMP	Risk Management Procedure
SAP	Enterprise System used for Asset Management and Work Management
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SME	Subject Matter Expert
SMYS	Specific Minimum Yield Strength
STPR	Strength Test Pressure Report
TIMP	Transmission Integrity Management Program
TVC	Traceable, Verifiable, Complete

G. Change Log

The following table will summarize revisions of this AMP when changes occur.

Table 6. Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
TBD	TBD	TBD	TBD

H. Dataset Condition Metrics

The criteria for the dataset condition status values are summarized in the following table.

Table 7. RAG Status Definitions for Dataset Condition Metrics

Data Attribute	Status		
	Green (3)	**Amber (2)**	**Red (1)**
Quality of Data	The data is complete, consistent, and accurate. The data can be used in the process or subsequent processes without edits.	The data is incomplete, inconsistent, and/or partially accurate. It is difficult to use in the process or subsequent processes without edits.	The data is not usable. The unit has to generate data for their internal use.
Data Accessibility	Data is centrally-located in an online or networked location accessible by the business.	Data is either: Distributed amongst multiple online or networked locations accessible by the business; or Resides in hard copy in a local repository (e.g., library, division office)	Data is not available or not accessible in an online or networked location or local repository.
Quality of Process	Data is managed (updated/maintained) according to a consistent and auditable process.	Data is managed in an ad-hoc fashion.	There is no apparent data management strategy.
Process Documentation	Documentation exists to govern the creation, maintenance, and update of data.	Minimal documentation exists to govern the creation, maintenance, and update of data.	No documentation exists to govern the creation, maintenance, and update of data. Relies upon institutional knowledge.
Management of Change	Formal management of change process applies when making major changes to data and data structure. Excludes day-to-day updates.	Ad-hoc management of change process applies when making major changes to data and data structure	No management of change process exists.

Data Attribute	Value	
	Yes	**No**
Acceptance Criteria	There is a documented standard for data quality / acceptance criteria.	There is no documented standard for data quality / acceptance criteria.
QC/Checking Process	There is a quality control or checking process for the data that is produced.	There is no quality control or checking process for the data that is produced.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 4

UTILITY STANDARD: GOV-6101S, ENTERPRISE CORRECTIVE

ACTION PROGRAM STANDARD, REV. 10

Pacific Gas and Electric Company®

Utility Standard: GOV-6101S

Publication Date: 05/15/2019 Rev: 10

Enterprise Corrective Action Program Standard

SUMMARY

This standard establishes requirements for Pacific Gas and Electric Company's (PG&E's) enterprise Corrective Action Program (CAP), which is intended to do the following:

- Identify and track actual and potential issues, problems, failures, nonconformities, concerns, and opportunities for improvement
- Enable personnel to identify opportunities for decreasing risk and improving safety, quality, and operational reliability.
- Evaluate risks and causes and implement corrective or preventive actions as appropriate.
- Selectively assess the effectiveness of corrective or preventive actions.
- Ensure consistent CAP governance, implementation, and effectiveness through enterprise-wide standardization of processes and tools.

TARGET AUDIENCE

All PG&E personnel

TABLE OF CONTENTS

Enterprise Corrective Action Program Standard

REQUIREMENTS

1 Applicability

1.1 This standard applies to identifying, reporting, and resolving asset, safety, performance and process-related issues involving or affecting any line of business (LOB) that are not reported through other reporting processes.

1.2 Each LOB may establish additional CAP requirements and procedures, but, at a minimum, comply with this enterprise standard and any implementing procedure(s).

2 Roles and Responsibilities

2.1 Executive Sponsor

- Ensures communication and alignment at the senior executive level.
- Works with ECAP process owner and LOB senior executives to ensure program requirements are supported and maintained.

2.2 Enterprise CAP Process Owner

- Chairs the CAP Governance Committee (CGC).
- Ensures periodic assessments of LOB CAPs.
- Reports program health to executive sponsor.
- Provides final approval for recommended CGC change requests to ECAP guidance documents and technology change requests.
- Promotes CAP continuous improvement through benchmarking, assessments, and implementation of industry best practices.
- Ensures the program, including support systems and infrastructure, is developed and maintained.
- Allocates enough resources for enterprise-level program development and implementation.
- Working with the CGC and LOB CAP process owners, develops training and communications to ensure employees understand CAP fundamentals.

2.3 CAP Governance Committee (CGC)

- Serves as the enterprise governing body for CAP.
- Comprised of LOB CAP process owners and the enterprise CAP process owner.

Enterprise Corrective Action Program Standard

2.3 (continued)

- Maintains a charter to guide the committee's activities.
- Oversees periodic assessments of program health.
- Reviews and recommends changes to guidance documents for the enterprise.
- Reviews and recommends changes to technology supporting CAP processes.
- Promotes CAP continuous improvement through benchmarking, assessments, and implementation of industry best practices.
- Ensures PG&E executive leadership has visibility into the status and details surrounding all significant issues.
- Ensures executive leadership has visibility into key enterprise and LOB CAP metrics to monitor overall program health, and to ensure successful adoption and execution of corrective actions at the LOB level.

2.4 LOB CAP Process Owner

- Designated by the LOB with responsibility and accountability for the day–to-day implementation, sustainability, and effectiveness of the LOB CAP.
- Ensures any LOB CAP procedures align with this enterprise CAP standard and any implementing procedure(s).
- Ensures that the LOB infrastructure and support systems enable the effective execution of CAP.
- Facilitates internal assessments of program compliance and recommends continuous improvements for LOB CAP implementation.
- Escalates LOB CAP and process issues and concerns to Enterprise CAP process owner.
- Provides oversight for LOB CAP team and ensures enough resources are allocated for LOB CAP program implementation.
- Ensures that the CAP review team (CRT) has members possessing expertise in a broad range of LOB departments.
- Serves on the CGC.

2.5 LOB CAP Specialist

- Designated by the LOB CAP process owner to facilitate LOB CRT meetings.
- Works with issue and action owners to ensure CAP execution and compliance.
- Supports LOB compliance with CAP and reporting requirements.
- Generates LOB program metrics and reports for LOB leaders.
- Analyzes LOB CAP data to identify trends that warrant investigation to determine if corrective actions are needed.
- Conducts cause evaluations PER Utility Standard GOV-6102S, "Enterprise Cause Evaluation Standard."

2.6 CAP Review Team (CRT)

- Comprised of LOB business subject matter expert(s) and members of the corresponding LOB CAP team.
    - LOB business subject matter expert(s) have been designated by LOB leadership as the key individuals whose collective knowledge and experience, possess expertise in abroad range of LOB departments within the LOB.
    - LOB business subject matter expert(s) are responsible for participating in the CRT process requirements and attending CRT meetings.
- Meets on a regular schedule to review incoming issue submissions.
- Responsible for initial review of issues, evaluating risk, updating key issue categories, and collecting more information as needed.
- Assigns "Close to Trend" (CTRD).
- Assigns issues to a responsible department.
- Assigns evaluations per GOV-6102S, "Enterprise Cause Evaluation Standard" and GOV-6102M, "Cause Evaluation Manual."

2.7 Initiator

- Any employee or contractor who submits an issue.
- Responsible for providing enough information, facts, and descriptive detail to allow reviewers to understand and follow-up on the issue.

Enterprise Corrective Action Program Standard

2.7 (continued)

- Do not enter any of the following information in an issue:
    - Inappropriate language or content [Utility Manual CDT-1001M, “Code of Conduct for Employees”]
    - Personally Identifiable Information (PII) [Utility Standard GOV-8001S “Customer Privacy Standard”]
    - Employee Record Information [Utility Standard HR-2001S, “Employee Files and Records Standard”]
    - Confidential or Restricted information [Utility Standard IT-5302S, “Information Classification and Protection Standard”]
    - Protected Health Information (PHI) [Utility Manual HR-1106M, “PG&E HIPAA Privacy Manual”]
    - Conduct Discipline [Utility Standard HR-5001S, “Conduct Discipline Standard for Support, Professional, and Leadership Employees”]

2.8 Department Owner

- Department owner responsible for reviewing all assigned issues from the CRT and either:
    - Accept the issue
        - Assign issue to an issue owner.
        - Verify and confirm assigned risk.
        - Verify and confirm assigned evaluation type.
        - Contact the LOB CAP team for changes to the assigned risk or evaluation type.
    - Request issue re-assignment
        - Provide justification for why issue does not belong to the assigned department
        - Identify the department best suited to address the issue
        - Contact the LOB CAP team for issue reassignment

Enterprise Corrective Action Program Standard

2.9 Issue Owner

- Responsible for managing day-to-day activities associated with issue.
- Manages issue in compliance with CAP standard and implementing CAP procedures
- Provides expertise and initiates actions to address issue.
- Performs evaluation PER GOV-6102S, “Enterprise Cause Evaluation Standard” and supported by GOV-6102M, “Cause Evaluation Manual.”
- Completes the “Training Needs Analysis” and submits to the PG&E Academy to address a potential training cause or solution to a CAP issue PER HR-7111P-04, “Training Needs Analysis Procedure” when appropriate.
- Assigns interim and/or mitigating actions for high risk issues.
- Assigns corrective or preventive actions when appropriate.
- Facilitates resources that will be responsible for executing actions.
- Monitors the progress of actions to ensure work is completed according to schedule.
- Updates CAP issues in CAP system with interim actions and progress.
- Ensures completion and quality of actions.
- Closes issue when all work has been completed.
- May plan and perform effectiveness reviews as needed.

2.10 Action Owner

- Executes assigned actions from the issue owner.
- Communicates status or concerns to the issue owner.
- Updates the CAP database with action status, completion date and properly documents actions taken.
- Closes action in CAP database when action is complete.

3 Required Program Elements

3.1 CAP Process

Enterprise Corrective Action Program Standard

1. This standard provides the baseline CAP process requirements to be used by LOBs to ensure consistency and standardization. LOBs may enhance the processes without detracting from the baseline process.

2. ECAP provides baseline technology to support CAP processes to be used by LOBs to ensure consistency and standardization and to support enterprise-wide reporting needs. Enhancements to the technology must be approved by the ECAP process owner.

3.2 The enterprise CAP process elements include the following:

1. Identify and report an issue

2. Review, categorize and assess risk

3. Perform issue evaluation

4. Resolve issue

5. Perform periodic review of closed issues for quality closure

6. Assess effectiveness of corrective or preventive actions (when appropriate)

7. Perform periodic analysis of issues to identify potential and/or actual trends

3.3 Identify and Report an Issue

1. The CAP process design and communication is intended to enable the following:

   a. Personnel can submit issues needing correction.

   b. Personnel are encouraged to report issues as specified in Appendix A, Examples of Issues to Report.

   c. Types of items that should be reported in other reporting solutions include, but are not limited to, the following:

      - Ethical issues
      - Injuries and motor vehicle incidents (MVIs)
      - Routine work management processes facilitated by another application
      - Routine observation processes facilitated by another application
      - Service requests, including Technical Service Center (TSC), facility issues (not related to industrial safety).
      - REFER to Appendix B, Other Reporting Solutions for more details.

2. Methods of submitting an issue include:

   a. CAP Website, “Submit an Issue” found at http://CAP/.

   b. CAP mobile solutions (CAP App and CAP full site).

   c. CAP Helpline at 1-855-85-GO-CAP (1-855-854-6227).

   d. CAP Help Desk Email (CAPHelp@pge.com)

   e. Fill out CAP issue paper submission form (See GOV-6101S, “Enterprise Corrective Action Program Standard,” Attachment 1, “Issue Paper Form”) and route through company mail to the address on the bottom of the form.

   f. SAP utilizing:

      (1) All users: "ZCAP_DESK" transaction code

      (2) Gas personnel: “ZIGAS” transaction code

      (3) Power Generation personnel: “ZHYDRO2” transaction code

3.4 Review, Categorize, and Assess Risk

1. The CRT or LOB CAP specialist must review issue submissions and edit any inappropriate information (SEE Step 2.7 above) while leaving the intent of the issue intact.

NOTE
Information that is edited from an issue is not retained, unless requested by LOB leadership or an approved PG&E program or process.

2. CRT must ensure enough pertinent, factual and descriptive information is provided so that issue owners can understand the issue and take action.

3. IF multiple submissions relating to the same issue are submitted to CAP,

   THEN the LOB CAP team and/or the CRT may recommend that the issues be combined, and subsequent issues be closed or canceled to the reference issue.

4. Each issue must be categorized and risk assessed utilizing CRT judgment and Safety or Quality Management personnel recommendation. The decision is aided by the CAP Risk Matrix tool (SEE Appendix C, Corrective Action Program Risk Matrix Tool) or another appropriate process-embedded risk determination tool at the discretion of the LOB management team.

a. The assessment process should include the determination of the need for any immediate or short-term controls or mitigation efforts to stabilize the situation or make it safe.

b. The level of response to an issue depends at a minimum on the level of associated risk to safety, reliability, financial impact, compliance, environment, and reputation.

(1) Safety personnel can recommend the risk level of issues related to safety incidents, observations or other assessments.

(2) Quality Management (QM) personnel can recommend the risk level of issues from official compliance oversight activities (i.e. audits, tests, inspections, assessments) submitted by QM.

(3) CAP issue risk may also be determined using Appendix C, CAP Risk Matrix Tool (SEE Appendix C, Corrective Action Program Risk Matrix Tool).

(4) CAP issue risk may also be determined based on another documented company program or process that establishes risk for specific program or process related issues.

5. The CRT determined business risk level may be changed based on new information from LOB program subject matter expert(s). Any of the following may recommend a change to risk:

a. CRT

b. LOB CAP process lead

c. Department owner

d. Issue owner

e. LOB leadership

6. Each issue must be assigned an evaluation type considering the level of associated risk to safety, reliability, financial impact, compliance, environment and reputation.

a. Root cause evaluations (RCEs) are required for all serious safety incidents (SSIs) and serious injury or fatality (SIF-Actuals).

b. CEs are required for all SIF potential (SIF-Potential) incidents.

c. For other issues related to safety, quality, and performance, the evaluation type is determined by the evaluation necessary for resolution. Any of the following may determine the type of evaluation necessary for issue resolution:

- CRT
- LOB CAP process lead
- LOB CAP team
- Department owners
- Issue owners
- LOB leadership

NOTE
LOB SIF review team utilizes the enterprise SIF assessment process flow to review incidents and near-hits within the LOB to determine if a SIF-Potential or SIF-Actual incident occurred and determine the cause evaluation type PER SAFE-1100S, “Serious Injury and Fatality (SIF) Program Standard.”

3.5 Perform an Evaluation

1. Issues requiring a cause evaluation (CE) must comply with Utility Standard GOV-6102S, “Enterprise Cause Evaluation Standard”.

2. All other CAP evaluations must comply with Utility Manual GOV-6102M, “Cause Evaluation Manual”.

3.6 Resolve Issue

1. Issue owners assigned to resolve an issue should develop an action plan to resolve the identified issue, as appropriate.

   a. For issues requiring a CE, actions should comply with GOV-6102S, “Enterprise Cause Evaluation Standard”.

   b. For other evaluation types, the issue owner will determine the actions necessary to address the issue.

      (1) For low risk issues that do not require additional action, issue owners may close the issue with adequate justification for closure (SEE Step 3.7).

   c. When training may be the cause or solution to a CAP issue, issue owners must complete and submit the “Training Needs Analysis” to the PG&E Academy PER HR-7111P-04, “Training Needs Analysis Procedure.”

2. Issue owners must ensure actions taken on the issue are:

a. Specific, Measurable, Actionable, Realistic, and Timely (SMART).

b. Prioritized based on importance.

c. Coordinated with the action owner for concurrence on the action to be taken and due date, if action is assigned.

d. Tracked to ensure successful implementation in a timely manner.

e. Verified as complete before the issue can be closed.

f. Completed with a statement detailing the steps taken to complete the action and supporting documentation.

3. Issue owners must provide an issue closure statement that:

a. Summarizes any actions taken to address the issue.

b. Describes how the issue was addressed.

c. Provides justification if no action was taken.

3.7 CAP Quality Closure Review (QCR)

1. For CAP issues completed each month, a minimum Quality Closure Review (QCR) of 100% high, 50% medium and 5% low risk issues must be performed to verify the following:

a. Issue is well defined.

b. Extent of condition is considered, when applicable.

c. Issue is not closed to a promise.

d. Actions taken are clearly documented.

e. Justification is provided if no action is taken.

3.8 Assess Effectiveness

1. REFER to Utility Procedure GOV-6102P-06, “Enterprise Cause Evaluation Process Procedure.”

3.9 Issue Trending

1. Issue data will be analyzed to identify positive and adverse trends. This will contribute to the determination of CAP effectiveness or the identification of an adverse trend warranting a new CAP issue.

Enterprise Corrective Action Program Standard

4 CAP Process Time Requirements

4.1 Within two business days of receipt, CRT must review CAP issues assigned to the LOB.

1. Exceptions to this requirement must be approved by the LOB CAP process owner.

4.2 Within five business days of receipt, Department owner must accept or contact the LOB CAP team for more information.

4.3 Issue owner must complete the issue by the assigned issue due date or modify the due date to allow adequate time to address the issue.

NOTE
Due date extension approvals do not need to escalate beyond the director unless required by another process.

4.4 Initial CAP issue due dates and subsequent extensions must be documented and approved as follows:

1. High and Medium Risk Issues:
   a. Due dates set 1 - 180 days from initiation require no approval.
   b. Due dates set 181 - 365 days from initiation require manager approval.
   c. Due dates requested beyond 365 days from initiation require director approval.
2. Low Risk Issues:
   a. Due dates set 1 - 365 days from initiation require no approval.
   b. Due dates set 366 - 730 days from initiation require manager approval.
   c. Due dates requested beyond 730 days from initiation require director approval.

4.5 Long Term Corrective Actions (LTCAs)

NOTE
LTCAs approval does not need to escalate beyond the director unless required by another process.

1. Long term corrective actions should be approved by the director or above in the issue owner's organization and LOB CAP process owner.
   a. Interim actions or mitigating actions must be in place and documented in the CAP issue.

b. Approval and rationale supporting the LTCA designation should be documented in the CAP issue (refer to step 2 below).

2. To be classified as an LTCA, the required completion time should be projected to exceed 180 calendar days and one or more of the following criteria should be met:

a. A system or power outage is required to implement corrective action(s).

b. A long lead time is projected to manufacture or procure parts.

c. A design change per applicable design change process is required.

d. Training will take multiple training cycles to complete.

e. A significant programmatic change is required.

f. Actions depend upon a submittal that requires government agency response or approval.

g. PG&E processes reject authorization of funds in the current fiscal year.

h. Other actions that may be designated by the LOB director or above.

3. CAP issues must be clearly designated as LTCA and, if applicable, identify the associated action as an LTCA.

5 Records

5.1 CAP issues and associated documents must be retained PER Utility Standard GOV-7101S, "Enterprise Records and Information Management Standard."

END of Requirements

DEFINITIONS

Cause Evaluation (CE): An evaluation based on readily available information that provides reasonable assurance that the cause of a problem is determined and will be corrected; used when management determines a formal but less rigorous cause determination is necessary.

Close to Trend (CTRD): An issue that does not require action. Value is in the classification data made available for analytical purposes, monitoring and determination of adverse trends.

Corrective Action: (1) A solution meant to reduce or eliminate an identified problem, including any action taken to resolve a finding or issue. (2) Restores an unacceptable or adverse condition to an acceptable condition or capability.

Extent of Condition: The extent to which the actual condition exists, or may exist, with other equipment, processes, or human performance.

Effectiveness Review Plan: A plan developed to verify that the intended or expected results were achieved after implementation of corrective actions. The plan includes the following: methods used to verify the actions met the desired outcome, attributes to be monitored and evaluated, success criteria, and expected timeline to perform the review.

Issue: An unwanted or undesired condition adverse to safety, quality, or performance

Incident: An unplanned sequence of events with the potential for undesirable consequences.

Interim Action: An action taken that is temporary in nature until final corrective actions are implemented.

Nonconformity: A deviation from a requirement of the asset management system, relevant policies, procedures, practices, work standards, legal requirements, etc.

Preventive Action: An action taken to prevent the occurrence of an issue.

Risk Assessment: The systemic evaluation of an issue to determine its probability of occurrence and the severity of the consequences of its occurrence.

Root Cause Evaluation (RCE) (sometimes referred to a root cause analysis [RCA]): A formal and rigorous investigation that uses industry-accepted 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).

Work Center: Functional department assigned to resolve the issue or action

Work Group Evaluation (WGE): A logical evaluation of an issue to identify reasonable corrective or preventive actions needed to resolve an issue. Resolution of the issue may be addressed by another process.

IMPLEMENTATION RESPONSIBILITIES

The enterprise CAP process owner will communicate this standard.

The enterprise CAP process owner will ensure distribution to appropriate line management and ensure training is provided to employees, as needed, to support the program.

Internal Audit (IA) conducts periodic reviews of the investigation process in accordance with the approved annual IA schedule.

GOVERNING DOCUMENT

GOV-03, Corrective Action Program Policy

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

NA

Enterprise Corrective Action Program Standard

REFERENCE DOCUMENTS

Developmental References:

- Department of Energy (DOE) - DOE G 414.1-5, "Corrective Action Program Guide"
- Diablo Canyon Power Plant – "OM7.ID1, Problem Identification and Resolution"
- Institute of Nuclear Power Operations – "Principles for Effective Self-Assessment and Corrective Action Programs"
- Title 50, "Code of Federal Regulations, Appendix B, QA Program"
- RISK-5001S, "Enterprise and Operational Risk Management Standard"
- PAS 55, "Optimal Management of Physical Assets (Publicly Available Speciation published by the British Standards Institution)"

Supplemental References:

- GOV-6102S, "Enterprise Cause Evaluation Standard"
- GOV-6102P-06, "Enterprise Cause Evaluation Process Procedure"
- HR-7111P-04, "Training Needs Analysis Procedure"
- SAFE-1100S, "Serious Injury and Fatality (SIF) Program Standard"

APPENDICES

Appendix A, Examples of Issues to Report

Appendix B, Other Reporting Solutions

Appendix C, Corrective Action Program Risk Matrix Tool

ATTACHMENTS

Attachment 1, "Issue Paper Form"

DOCUMENT RECISION

NA

DOCUMENT APPROVER

Director, ECAP (Executive CAP Sponsor)

Enterprise Corrective Action Program Standard

DOCUMENT OWNER

Manager, ECAP (Enterprise Corrective Action Program)

DOCUMENT CONTACT

Manager, ECAP (Enterprise Corrective Action Program)

REVISION NOTES

Where?	What Changed?
Step 2.6	Updated “close to trend” with corresponding CAP system code. Revised responsibility to assign an issue to a department. Changed cause evaluation assignment to evaluation assignment. Added reference to GOV-6102M.
Step 2.7	Provided specific guidance document references for information which should not be included in issue submissions.
Step 2.9	Added reference to Gov-6102M. Added “when appropriate” to bullet point 5 and 6. Changed CAP database to CAP System for bullet point 9.
Step 3.2.5	Added Quality Closure Review as new CAP program element.
Step 3.2.7	Added trend analysis as new CAP program element.
Step 3.3.2	Updated wording to align with GOV-6101P-08.
Step 3.4.3	Updated methods to determine risk.
Step 3.4.3.b.1	Added safety personnel as potential course for assigning risk.
Step 3.4.3.b.3	Added reference to Appendix C, CAP Risk Matrix Tool.
Step 3.4.3.b.4	Added other process-embedded risk determination tools as resources for assigning risk.
Step 3.4.4	Specified personnel that may recommend changes to risk.
Step 3.4.5	Updated to distinguish between cause evaluations and other evaluation types.
Step 3.5.12	Referenced GOV-6102M
Step 3.6.1	Change step to develop an action plan as appropriate.
Step 3.6.1.a	Reference GOV-6102S for cause evaluations.
Step 3.6.1.b	Add guidance for action plan development for other evaluation types.
Step 3.6.3	New step to require a closure statement upon issue closure.
Step 4.4	Added new approval requirements for CAP issue due dates and subsequent extensions. Approvals based on number of extensions was removed.
App. A Example of Issues to Report	Updated content to align with existing CAP issue types. Changed format from table to list. Moved table B to new appendix B.

App. B Other Reporting Systems	New Appendix B, previously found on Appendix A Table 2.
App. C Risk Matrix Tool	Changed to Appendix C.

Appendix A, Examples of Issues to Report
Page 1 of 2

CORRECTIVE ACTION PROGRAM ISSUE TYPES

The following are examples of the types of issues that should be entered in CAP:

Company Relations: Issues involving the Company Brand, or as reported in the media

Compliance: Audit, Quality Assurance, Enterprise Risk, Permit Conditions, Regulator Compliance or other Compliance-related issues

Customer Trust: Issues involving customer satisfaction

Emergency Management: Issues related to emergency management activities, including exercises

Engineering: Issues involving design, quality related engineering processes or programs, or other engineering evaluation requests

Environmental: Issues related to environmental factors and concerns including hazardous materials and handling, environmental permits, environmental compliance, or other environmental-related regulations

Equipment: Equipment issues requiring investigation, including material conditions, mobile vehicles, office equipment, tools, utility infrastructure or other equipment-related concerns

Facilities: Issues related to non-CRESS managed sites such as substations, storage fields, aviation hangers/helipads, spoils bunkers, compressor and regulator stations

Financial: Issues related to affordability, expenses, financial costs or payment services

Guidance Documents: Policies, standards, procedures, bulletins or drawings that are inadequate, unavailable, conflicting or outdated

IT: Issues beyond the normal TSC submittal process related to system technology applications, computing, IT devices/tools, hardware, software, network and transmission, telecommunication equipment, or other non-TSC supported IT issues.

Operations: Operation issues related to system or infrastructure capabilities, such as clearances, control of gas, or gas quality

Program / Process: Issues involving improvements related to people or business processes, or issues that are raised as a general concern that do not otherwise fit other issue categories.

Records: Issues that consist of inadequate, incomplete conflicting, or unavailable records; issues related to records storage, integrity, classification or storage/protection.

Enterprise Corrective Action Program Standard

Appendix A, Examples of Issues to Report
Page 2 of 2

Reliability: Issues that may impact the company's commitment to reliability, including dig-ins, unplanned outages, maintenance and asset management.

Safety & Health: Safety related issues such as: near hits, public safety, clearance issues, confined space, electrical safety, excavation safety, fire safety, industrial safety, safety at heights and vehicle safety

Security: Issues related to physical or cyber security

Supply Chain: Issues related to contract administration, warehouse management, suppliers, materials management and purchasing.

Training: Issues or concerns related to company-offered training and/or apprenticeship programs

Appendix B, Other Reporting Solutions
Page 1 of 1

Examples of other reporting solutions for issues that should not be submitted to CAP

- Compliance and Ethics Helpline
- Electric Map Correction Tool
- Facilities Management
- Federal Monitor Hotline
- Human Resource (HR)
- Here to Help Hotline
- Injury
  - 24/7 Nurse Care Line: 1-888-449-7787
  - CareOnSite: 1-888-888-8656
- IT Service / Hardware Requests (SMC)
- Material Problem Reports (MPR)
- Motor Vehicle Incident (MVI)
- Security
- Self-Care
- Spark Idea Marketplace

Appendix C, Corrective Action Program Risk Matrix Tool

Page 1 of 1

SEVERITY	(*Probability of Event Occurrence*) **FREQUENCY** →	**D** **Rare** Once every 10+years	**C** **Possible** Once every 2-10 years	**B** **Likely** 1 - 3 times per year	**A** **Almost Certain** > 3 times per year
1	One of the following occurred: 1. Serious Injury or Fatality (SIF Actual) to the public, employees or contractors or employee injury requiring 24-hour hospitalization (other than observation) 2. Catastrophic damage to critical asset(s) 3. Widespread loss of service 4. Financial loss > $250M 5. Pipeline or facility shut down by regulatory agency 6. Catastrophic environmental effect 7. Extended national / international media coverage	**High**	**High**	**High**	**High**
2	One of the following occurred: 1. Lost Time Injury or many minor injuries or SIF Potential 2. Major damage to critical asset(s) 3. Limited loss of service 4. Financial loss $7M-250M 5. Regulatory penalty/legal action results in fine within financial loss range 6. Widespread environmental effect 7. Extended state media coverage	**Medium**	**Medium**	**High**	**High**
3	One of the following occurred: 1. Recordable Injury or few minor injuries or Significant Safety Concern 2. Damage/degradation of critical asset(s) 3. Threat to continuity of service 4. Financial loss $200k-7M 5. Warning letter, notice of violation, audit results in fine within financial loss range 6. Localized environmental effect 7. Local / Limited state media coverage issue 8. Significant recurring program, process or compliance gap	**Low**	**Medium**	**Medium**	**High**
4	One of the following occurred: 1. First Aid or Safety Concern or Near Hit 2. Limited or no damage to assets 3. No threat to continuity of service 4. Financial loss <$200k 5. Self-reported Inspection, Audit, or QC Finding or Regulator identified violations with no fines or penalties. 6. Limited or no environmental effect 7. Limited local or no media coverage 8. Improvement suggestions, administrative, tracking, and similar issues.	**Low**	**Low**	**Low**	**Low**

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 5

UTILITY PROCEDURE: GOV-6101P-08, CORRECTIVE ACTION PROGRAM PROCEDURE, REV. 0

Corrective Action Program Procedure

SUMMARY

This utility procedure establishes the requirements for the enterprise-wide Corrective Action Program (CAP) process across lines of business (LOBs) at PG&E.

The purpose of CAP is to identify, evaluate, resolve, and track actual or potential issues, problems, failures, nonconformities, concerns, and opportunities for improvement (collectively, CAP issues) based on probability of occurrence. CAP is a risk-informed, risk-driven process by which the organization learns from equipment, programmatic, organizational, human performance issues and successes.

This procedure provides the framework to ensure personnel (collectively, employees and non-employees) concerns, process issues, unsafe conditions, operability issues, compliance and quality issues are promptly identified, evaluated, and either corrected or accepted as is.

The development and maintenance of the nuclear generation CAP process is governed by program guidance documents that specifically address Nuclear Regulatory Commission and nuclear insurer requirements. See Inter-Departmental Administrative Procedure (IDAP) OM7.ID1, “Problem Identification and Resolution” for specific guidance.

Level of Use: Informational Use

TARGET AUDIENCE

This procedure applies to all personnel engaged in the enterprise-wide CAP when performing work under PG&E procedures and governance processes.

See Utility Standard GOV-6101S, “Enterprise Corrective Action Program Standard”, section 4 for CAP Roles and Responsibilities.

SAFETY

Following the requirements of this procedure demonstrates each LOB’s commitment to PG&E’s goal of improving employee, contractor, and public safety.

BEFORE YOU START

COMPARE the publication date and version number on your working copy of the document against the published version in the Guidance Document Library to verify that it is current.

Corrective Action Program Procedure

TABLE OF CONTENTS

SUBSECTION TITLE PAGE

PROCEDURE STEPS

1 Identify and Submit CAP Issue

1.1. Initiator

1. SUBMIT only one issue per submission.

   a. Each submission should only address one specific topic. (SEE Appendix A, Examples of Issues to Report)

   b. Existing PG&E reporting solutions should continue to be used as intended. (SEE Appendix B, Other Reporting Solutions)

2. REPORT an issue as soon as practical.

   a. REPORT an issue, even if it is resolved, for tracking and trend analysis.

b. IF there is doubt about the need to submit an issue:

THEN SUBMIT the issue.

NOTE

CONTACT the LOB CAP team for assistance if sensitive or protected information must be included in the CAP issue.

3. Do not enter any of the following information in an issue:

   a. Inappropriate language or content [Utility Manual CDT-1001M, “Code of Conduct for Employees”]

   b. Personally Identifiable Information (PII) [Utility Standard GOV-8001S “Customer Privacy Standard”]

   c. Employee Record Information [Utility Standard HR-2001S, “Employee Files and Records Standard”]

   d. Confidential or Restricted information [Utility Standard IT-5302S, “Information Classification and Protection Standard”]

   e. Protected Health Information (PHI) [Utility Manual HR-1106M, “PG&E HIPAA Privacy Manual”]

   f. Conduct Discipline [Utility Standard HR-5001S, “Conduct Discipline Standard for Support, Professional, and Leadership Employees”]

4. REPORT the issue using one of the following methods:

   a. CAP Website, “Submit an Issue” found at http://CAP/.

   b. CAP mobile solutions (CAP App and CAP Full Site).

   c. CAP Helpline at 1-855-85-GO-CAP (1-855-854-6227).

   d. CAP Help Desk Email (CAPHelp@pge.com)

   e. Fill out CAP issue paper submission form (See GOV-6101S, “Enterprise Corrective Action Program Standard”, Attachment 1, “Issue Paper Form”) and route through company mail to the address on the bottom of the form.

   f. SAP utilizing:

      (1) All users: "ZCAP_DESK" transaction code

      (2) Gas personnel: “ZIGAS” transaction code

(3) Power Generation personnel: "ZHYDRO2" transaction code

5. IDENTIFY the organization best suited to take ownership of the issue.

6. ENTER a brief title to describe the issue.

7. ENTER a detailed description of the issue, including:

   a. What and where is the issue?

      - DESCRIBE the issue as clearly and concisely as possible, including the process of what should have occurred, any applicable guidance document(s), deviation from those document(s), and any potential or known consequences.

      - PROVIDE the location of the issue when pertinent to the issue.

   b. Who should be assigned to address this issue?

      - RECORD the department or title of the individual who should be assigned to address the issue, if known.

   c. How might this issue be avoided or solved?

      - EXPLAIN what may have caused the issue, and the basis for the assumption, and provide any suggestions or information on how the issue could be resolved, if known.

      - DOCUMENT immediate and completed actions taken, if any.

8. PROVIDE enough information to allow for appropriate issue follow up and assignment.

NOTE

SEE 1.1.3 above for guidance on information that should not be included in the CAP issue.

9. IF supporting documents or evidence such as photographs, procedures, or other documentation (i.e. gas map correction form, etc.) can provide understanding and / or assistance with resolving the issue:

   THEN ATTACH the supporting document(s) or evidence to the issue.

10. COMPLETE any additional fields if information is known (example: issue type, subtype division/district, etc.).

11. REQUEST the issue owner to contact the Initiator prior to issue closure, if desired.

NOTE
Anonymous Initiators will need to save the CAP issue number generated on submission to track submission results as they will NOT receive: status email updates, follow-up questions or access to rate their satisfaction on how the CAP issue was closed.

12. When reporting an issue anonymously, the initiator must INCLUDE enough descriptive information so that appropriate follow-up action can be taken.

2 Review, Categorize, and Risk Assess

NOTE
The LOB CAP specialist is responsible for facilitating CAP review team (CRT) meetings including; agenda and recording CRT actions. CRT members (LOB subject matter expert[s]) are responsible for executing the CRT process requirements and participating in CRT reviews.

2.1. LOB CAP Specialist

1. REVIEW CAP issue submissions within two business days of receipt.
   a. Exceptions to this requirement must be approved by the LOB CAP process owner.
2. ENSURE the issue has enough information, facts, and descriptive detail to allow reviewers to understand and follow-up on the issue.
   a. IF additional information is needed to support risk assessment or assignment of the issue:

      THEN OBTAIN the information and UPDATE the CAP issue.
   b. IF unable to obtain additional issue information:

      THEN USE LOB CAP specialist and CRT judgment for issue review.
3. IF there are multiple CAP submissions for initial identification of the same issue,

   THEN the LOB CAP team and/or the CRT may recommend that the issues be combined, and subsequent issues be closed or canceled to the reference issue.
4. IF the issue submission has any inappropriate information as defined in step 1.1.3 above,

   THEN one or more of the following may occur:

a. TRANSFER the issue to the appropriate reporting solution for disposition

(1) EDIT the information from the CAP system

(2) CLOSE the issue to the other reporting solution.

b. OR EDIT the inappropriate information while leaving the intent of the issue intact,

c. OR APPLY the “Protected” status to the issue in the CAP system.

5. PREPARE the CRT meeting agenda and CRT package.

6. DISTRIBUTE the CRT meeting agenda and CRT report to attending CRT members.

7. PUBLISH the CRT meeting agenda and CRT package to the LOB CAP website or otherwise make them available to CRT for review.

2.2. LOB CAP Specialist and/or LOB CRT Member

1. REVIEW the CRT meeting agenda and CRT Report in preparation for the CRT meeting.

2. CATEGORIZE the submitted CAP Issue.

a. REVIEW and UPDATE the CAP issue type and sub-type as appropriate.

b. DOCUMENT the recommended CAP risk level using the CAP Risk Matrix Tool found in Utility Standard GOV-6101S, Appendix B, “CAP Risk Matrix Tool.”

(1) DOCUMENT the rationale used to determine the recommended CAP risk level in the CAP issue description field.

c. DETERMINE IF the CAP issue should be evaluated for extent of condition.

d. REVIEW and UPDATE any additional fields as appropriate.

e. IDENTIFY attributes to CAP issue, if known or as applicable.

3. RECOMMEND an evaluation type considering the assignment on the level of associated risk to safety, reliability, financial impact, compliance, environment, and reputation.

Corrective Action Program Procedure

> NOTE
>
> For issues that do not meet the criteria for serious safety incident (SSI), serious injury or fatality-actual (SIF-Actual) or serious injury or fatality-potential (SIF-Potential), evaluation type is determined by LOB management, LOB CAP team, LOB CRT team or the issue owners.
>
> For specific Gas Operations CAP issues requiring a cause evaluation, refer to Appendix G.
>
> Cause evaluations are only required for issues that meet Safety criteria as described above. For all other CAP issues, including high and medium risk, a work group evaluation (WGE) or close to trend (CTRD) are acceptable evaluation types.

a. Root Cause Evaluation (RCE)

ASSIGN to all SSIs and SIF-Actual incidents PER Utility Procedure SAFE-1100S, “Serious Injury and Fatality (SIF) Standard.”

b. Cause Evaluation (CE)

ASSIGN a cause evaluation (CE) to all SIF-Potential incidents.

c. Common Cause Evaluation (CCE)

ASSIGN to identify common underlying elements between different, unique, but similar causes, issues or incidents.

d. Work Group Evaluation (WGE)

ASSIGN to an issue to perform a logical evaluation, not rising to the rigor of a CE, that requires a logical evaluation be performed to identify reasonable corrective or preventive actions needed to resolve an issue.

e. Effectiveness Review

ASSIGN only to issues created to implement an existing cause evaluation’s effectiveness review plan.

f. Close to Trend (CTRD)

ASSIGN when the issue addressed in the CAP issue does not require any additional action or response.

CLOSE issue and DOCUMENT basis for closure or allow the issue owner to validate as CTRD and close.

4. IDENTIFY potential trends.

5. IDENTIFY potential Eagle Eye Award candidates.

2.3. CRT Meeting

1. MEET on a basis defined by the LOB CAP process owner to review CRT packet.

2. GAIN CONSENSUS on pre-identified information from steps 2.2.2 – 2.2.5.

2.4. LOB CAP Specialists Post-CRT

1. UPDATE CAP issues reviewed during CRT meeting with any changes recommended by CRT.

2. IF the CRT has recommended that the CAP issue should be evaluated for extent of condition THEN:

   a. INCLUDE in the CAP issue Description

   b. AND/OR CREATE an extent of condition action assigned to the identified department owner.

3. IF during the CRT meeting the CRT members are unable to establish ownership of a CAP issue within the LOB organization, THEN:

   a. PLACE the issue on hold for further follow-up.

   b. INITIATE an issue transfer between LOB (See section 2.5), as needed.

4. DISTRIBUTE the CRT materials, as needed.

2.5. LOB CAP Specialist – Transfer Issue to another Organization (LOB)

1. IF the CRT recommends that an issue be owned by a different organization:

   a. DOCUMENT the organization that should own the issue.

   b. EXPLAIN why the organization suggested should own the issue.

   c. INITIATE an organization transfer in the CAP system.

2. IF the transfer request is not accepted:

   a. CONSULT with the LOB SMEs and other LOB CAP teams to identify appropriate ownership AND

   b. INITIATE a new transfer in the CAP system, if needed.

c. OR PLACE the issue on hold pending additional information

2.6. Transfer Issues to other reporting solution

1. Issues that will be transferred to another reporting solution should first be transferred to the organization that owns the other reporting solution.

2. The LOB CAP specialist, issue owner or process designee will PERFORM the following:

   a. INFORM the CAP initiator of the status of the CAP issue.

   b. SUBMIT the issue from CAP into the appropriate reporting solution to address the issue.

   c. ENSURE the issue is traceable in the new reporting solution.

   d. CHANGE status of the CAP issue to “Other Reporting Solution”.

   e. CLOSE the CAP issue.

2.7. Escalation Process

1. IF the CRT team is unable to establish ownership of a CAP issue within the LOB organization or another LOB via the transfer process within two weeks following the CRT review.

   a. PLACE the issue on hold.

   b. NOTIFY the LOB CAP process owner.

NOTE
The decision to escalate the issue ownership discussion to the executive leadership team is based on agreement between the LOB CAP Process Owner, associated LOB management team member(s) and/or enterprise CAP director.

2. ESCALATE issue ownership agreement discussion to the LOB management team.

   a. SCHEDULE discussions or meetings with managers, directors, CAP initiator and any company officer (as needed) that is associated with the issue.

   b. INCLUDE stakeholder procedures related to the issue.

   c. CONSIDER including the enterprise CAP manager or director in discussions or meetings to achieve final ownership.

   d. DETERMINE ownership for the CAP issue.

3. IF issue ownership is not achieved by the LOB management team, ESCALATE issue ownership discussion to the LOB executive leadership team.

   a. SCHEDULE discussion or meeting with the executive leadership team or designated alternates.

   b. ESTABLISH ownership for the CAP issue.

3 Accepting and Assigning the CAP Issue

3.1. Department Owner

NOTE
IF the issue is not accepted in five business days, THEN the issue will be automatically accepted, and the department owner will become the issue owner.

1. REVIEW the issue within five business days of the CRT assignment.

2. IF the issue was assigned to the appropriate department:

   a. REVIEW the existing issue owner assignment

      OR ASSIGN the CAP issue to the appropriate issue owner by entering the LAN ID of the CAP issue owner.

   b. ACCEPT the issue.

3. IF the CAP issue requires a change in risk level THEN:

   a. NOTIFY the LOB CAP team process owner for approval to adjust the risk level.

   b. DOCUMENT the justification as to why the CAP issue risk level needs to change and recommended risk level within the CAP issue.

4. IF the CAP issue requires a change in evaluation type,

   THEN REFER to Utility Standard GOV-6102S, “Enterprise Cause Evaluation Standard”

   AND Utility Standard SAFE-1100S, “Serious Injury and Fatality (SIF) Standard.”

5. IF the CAP issue assignment is not accepted,

   THEN DOCUMENT the justification as why the CAP issue does not belong to the department

   AND NOTIFY the LOB CAP team for reassignment.

3.2. Issue Owner

1. REVIEW the issue.

   a. IF additional information is required

      THEN CONTACT the initiator, if known.

2. VALIDATE the CRT assigned evaluation type.

   a. IF the assigned type of evaluation should be modified:

      THEN CONTACT the issue department owner to request an evaluation change (SEE step 3.1.4 above).

3. REVIEW the issue due date.

4. CHANGE the due date to an appropriate date to address the issue, if needed.

NOTE
Due date extension approvals do not need to escalate beyond the director unless required by another process.

5. Extensions to the CAP issue due date must be APPROVED AND DOCUMENTED as follows:

   a. **High and Medium Risk Issues:**

      (1) Due dates set 1 - 180 days from initiation require no approval.

      (2) Due dates set 181 - 365 days from initiation require manager approval.

      (3) Due dates requested beyond 365 days from initiation require director approval.

   b. **Low Risk Issues:**

      (1) Due dates set 1 - 365 days from initiation require no approval.

      (2) Due dates set 366 - 730 days from initiation require manager approval.

      (3) Due dates requested beyond 730 days from initiation require director approval.

6. IF the assigned issue should be close to trend:

   THEN ENSURE the following steps are performed and recorded in the CAP system:

a. DOCUMENT the basis for close to trend

b. COMMUNICATE the decision to the issue initiator.

c. CONTACT the LOB CAP team to request a status change.

4 Perform an Evaluation

4.1. Issue Owner

1. CREATE and IMPLEMENT interim or mitigating actions for all high risk issues.

   a. DOCUMENT the action(s) in the CAP issue.

2. IF an RCE, CE or CCE has been assigned:

   a. THEN REFER to Utility Procedure GOV-6102P-06, “Enterprise Cause Evaluation Process Procedure.”

   b. DOCUMENT the findings, causes, and corrective or preventive actions as required by the CE procedure, in the CAP issue.

3. IF a WGE has been assigned:

   a. THEN PERFORM a WGE PER Utility Manual GOV-6102M, “Cause Evaluation Manual.”

4. IF close to trend is assigned:

   a. VERIFY that no further action is required to address the issue.

   b. COMPLETE issue per step 3.2.6 above.

5. IF an effectiveness review is assigned

   a. THEN PERFORM an effectiveness review evaluation as described in Utility Procedure GOV-6102P-06, “Enterprise Cause Evaluation Process Procedure.”

6. IF an extent of condition has been recommended by the CRT, or at the department owner, issue owner, or LOB leadership’s direction:

   a. EVALUATE the extent of condition to determine if the identified issue exists, or may exist, with other processes, human performance or equipment as described in Utility Manual GOV-6102M, “Cause Evaluation Manual.”

   b. DOCUMENT the findings, causes, and corrective or preventive actions as required by Utility Procedure GOV-6102S, “Enterprise Cause Evaluation Standard.”

5 Resolving an Issue

NOTE
SEE step 1.1.3 above for guidance on information that should not be included in the CAP issue.

5.1. Issue Owner

NOTE
Low risk issues that do not require additional action can be closed by the issue owner with justification for closure.

1. DEVELOP and IMPLEMENT reasonable action(s) to resolve the issue proportionate to the risk level of the issue.

   a. IF CE is for a SIF-Actual or SIF-Potential:

      THEN SEE GOV-6102P-06, “Enterprise Cause Evaluation Process Procedure”.

   b. ENSURE the corrective action(s) for resolving the issue are specific, measurable, actionable, realistic, and timely (SMART).

   c. ENSURE the schedule for implementing the action(s) are appropriate and realistic for the risk presented by the issue.

   d. COORDINATE with the action owner for concurrence on the action to be taken and the action due date.

   e. ENSURE that the use of resources is commensurate with level of risk.

   f. IF training may be the cause or solution to resolve the CAP issue:

      THEN COMPLETE and SUBMIT the “Training Needs Analysis” to the PG&E Academy PER Utility Procedure HR-7111P-04, “Training Needs Analysis Procedure.”

   g. DOCUMENT the action(s) in the CAP issue

2. IF actions are generated

   THEN ENSURE each action includes:

   a. Action title and the detailed description.

   b. Action owner’s LAN ID and department.

   c. Planned start date and planned finish date.

3. VERIFY the issue's due date is realistic and achievable for the developed action plan(s).

    a. Action due dates can NOT exceed the issue due date.

    b. UPDATE the issue due date as necessary PER step 3.2.5 above.

5.2. Action Owner

1. COMPLETE the actions assigned by the issue owner.

2. IF the agreed action due date needs to be extended:

    THEN CONTACT the issue owner to AUTHORIZE the extension.

3. DOCUMENT the actions taken in the CAP system.

    a. ENSURE that the documentation is detailed enough to provide justification of completion. INCLUDE:

        - A detailed closure statement of the actions taken to address the issue.

        - The date the action was completed.

    b. PROVIDE a reference to any documents that detail the actions taken, when applicable. For example, when the action is for a new or revised procedure, INCLUDE the following information:

        - Procedure number.

        - Revision number.

        - Publication date.

        - A brief description of the change.

        - A description of how the change addresses the issue.

4. REVIEW action taken with the issue owner for agreement.

5. COMPLETE the action.

5.3. Issue Owner - Verify Completion of Corrective Actions

1. REVIEW the action(s) completed by the action owner.

2. VERIFY that the action(s) are complete and appropriately documented,

3. ENSURE inappropriate information is not included in the action (SEE step 1.1.31.1.3 above).

4. VERIFY that supporting references such as photographs, revised procedures, or other documentation are attached to the issue, or otherwise traceable.

5. IF the action does not meet action assignment requirements,

   THEN INITIATE a new CAP action.

5.4. Issue Owner – Complete the Issue

NOTE
CAP issues cannot be closed until all CAP Actions have been completed.

1. ENSURE justification is documented if no action is taken, and/or if the issue owner determines that the issue will not be resolved at this time.

2. ENSURE there are traceable references that can be retrieved by others for high and medium risk issues.

3. ENSURE inappropriate information is not included in the action (SEE step 1.1.3 above).

4. CONTACT the initiator to discuss the closure and actions taken, if requested.

5. CLOSE the CAP issue in the CAP system.

6 Long Term Corrective Actions (LTCAs)

6.1. To be classified as an LTCA, the required action completion time to resolve the CAP issue should be projected to exceed 180 calendar days and one or more of the following criteria must be met:

1. A system or power outage is required to implement corrective action(s).

2. A long lead time is projected to manufacture or procure parts.

3. A design change per applicable design change process is required.

4. Training will take multiple training cycles to complete.

5. A significant programmatic change is required.

6. Actions depend upon a submittal that requires government agency response or approval.

7. PG&E processes reject authorization of funds in the current fiscal year.

8. Other actions that may be designated by the LOB director or above.

> **NOTE**
>
> LTCAs approval does not need to escalate beyond the director unless required by another process.

6.2. LTCA should be approved by the director or above in the issue owner's organization and LOB CAP process owner.

1. Interim actions or mitigating actions must be in place and documented in the CAP issue.

2. DOCUMENT approval and rationale supporting the LTCA designation in the CAP issue (REFER to step 6.1 above).

6.3. IF a CAP issue has been recommended for LTCA designation:

THEN CONTACT the LOB CAP team.

7 Quality Closure Review (QCR)

7.1. LOB CAP Team

1. REVIEW CAP issues completed each month for quality.

> **NOTE**
>
> Any portion of CAP issues not predesignated for QCR by the review minimum and other management review process will be randomly selected.

a. REVIEW, at a minimum:

- 100% high risk issues
- 50% medium risk issues
- 5% low risk issues

2. VERIFY issues meet quality closure review criteria (REFER to Appendix C, Quality Closure Criteria for CAP Issues).

a. Issue is well defined.

b. Extent of condition is considered, when applicable.

c. Issue is not closed to a promise.

d. Actions taken are clearly documented.

e. Justification is provided if no action is taken.

3. DOCUMENT QCR results by adding the appropriate attribute code(s) to the CAP issue.

4. IF closure is not satisfactory:

   a. INFORM the issue owner that closure was unsatisfactory.

   b. RE-OPEN the CAP issue, if required.

   c. EXTEND the issue due date to allow issue owner to take necessary action as needed.

8 Effectiveness Review

8.1. REFER to Utility Procedure GOV-6102P-06, "Enterprise Cause Evaluation Process Procedure."

9 Trending

9.1. LOB CAP Team

1. PERFORM periodic review of CAP issues on a frequency defined by the LOB CAP process owner.

2. PROVIDE results to management, which should include the following information:

   a. The time frame being reviewed.

   b. A list of potential or actual adverse trends that warrant attention.

   c. A summary statement documenting the results of the review.

3. INITIATE a new CAP issue if needed to address potential adverse trends.

END of Instructions

DEFINITIONS

Refer to the "Definitions" section of Utility Standard GOV-6101S, "Enterprise Corrective Action Program Standard" and Utility Standard GOV-6102S, "Enterprise Cause Evaluation Standard."

IMPLEMENTATION RESPONSIBILITIES

ECAP manager ENSURES this procedure complies with Utility Standard GOV-6101S, "Enterprise Corrective Action Program Standard."

LOB CAP process owners ENSURE that their employees are aware of and comply with the requirements of this procedure.

Employee(s) identified and held accountable by the organization for fulfilling specific responsibilities described in this procedure may DELEGATE their responsibilities to others; however, they are accountable for the final results.

GOVERNING DOCUMENT

Utility Standard GOV-6101S, “Enterprise Corrective Action Program Standard”

Utility Standard GOV-6102S, “Enterprise Cause Evaluation Standard”

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Kern OII Decision Approving Settlement Agreement, Decision 15-07-014 July 23, 2015

REFERENCE DOCUMENTS

Developmental References:

- Corporation Policy GOV-01, “Records Management Policy”
- Utility Standard GOV-6101S, “Enterprise Corrective Action Program Standard”
- Utility Standard GOV-6102S, “Enterprise Cause Evaluation Standard”
- Utility Standard SAFE-1004S, “Serious Incident Investigation Standard”
- Utility Standard SAFE-1100S, “Serious Injury and Fatality (SIF) Program Standard”
- Utility Procedure GOV-6102P-06, “Enterprise Cause Evaluation Process Procedure”

Supplemental References:

- Utility Standard GOV-8001S, “Customer Privacy Standard”
- Utility Standard IT-5302S, “Information Classification and Protection Standard”
- Utility Manual GOV-6102M, “Cause Evaluation Manual”

APPENDICES

Appendix A, Examples of Issues to Report

Appendix B, Other Reporting Solutions

Appendix C, Quality Closure Criteria for CAP Issues

Appendix D, Closure Documentation Guidance for Corrective Actions

Appendix E, Gas Operations Minimum Requirements for Cause Evaluation

ATTACHMENTS

N/A

DOCUMENT RECISION

This utility procedure cancels and supersedes the following LOB CE procedures:

- Utility Procedure GOV-6101P-01, "Safety and Corporate Services Corrective Action Procedure," 07/20/2017, Rev.3
- Utility Procedure GOV-6101P-02, "Power Generation Corrective Action Program (CAP) Procedure," 07/21/2016, Rev.0
- Utility Procedure GOV-6101P-03, "Electric Corrective Action Program (CAP) Procedure," 06/25/2018, Rev.1
- Utility Procedure GOV-6101P-06, "IT/Supply Chain Corrective Action Program (CAP)," 06/22/2017, Rev.0
- Utility Procedure GOV-6101P-07, "Customer Care Corrective Action Program (CAP)," 06/22/2017, Rev.0
- Utility Procedure TD-4020P-01, "Gas Corrective Action Program," 01/01/2017, Rev.4a

DOCUMENT APPROVER

Director, ECAP (Executive CAP Sponsor)

DOCUMENT OWNER

Manager, ECAP (CAP Process Owner)

DOCUMENT CONTACT

Manager, ECAP (CAP Process Owner)

REVISION NOTES

Where?	What Changed?
N/A	Created new Enterprise CAP procedure consolidating all LOBs CAP procedures to clearly define the PG&E CAP process required elements for consistent application.

Corrective Action Program Procedure

Appendix A, Examples of Issues to Report
Page 1 of 2

CORRECTIVE ACTION PROGRAM ISSUE TYPES

The following are examples of the types of issues that should be entered in CAP:

Company Relations: Issues involving the company brand, or as reported in the media

Compliance: Audit, quality assurance, enterprise risk, permit conditions, regulatory compliance or other compliance-related issues

Customer Trust: Issues involving customer satisfaction

Emergency Management: Issues related to emergency management activities, including exercises

Engineering: Issues involving design, quality related engineering processes or programs, or other engineering evaluation requests

Environmental: Issues related to environmental factors and concerns including hazardous materials and handling, environmental permits, environmental compliance, or other environmental-related regulations

Equipment: Equipment issues requiring investigation, including material conditions, mobile vehicles, office equipment, tools, utility infrastructure or other equipment-related concerns

Facilities: Issues related to non-CRESS managed sites such as substations, storage fields, aviation hangers/helipads, spoils bunkers, compressor and regulator stations

Financial: Issues related to affordability, expenses, financial costs or payment services

Guidance Documents: Policies, standards, procedures, bulletins or drawings that are inadequate, unavailable, conflicting or outdated

IT: Issues beyond the normal TSC submittal process related to system technology applications, computing, IT devices/tools, hardware, software, network and transmission, telecommunication equipment, or other non-TSC supported IT issues.

Operations: Operation issues related to system or infrastructure capabilities, such as clearances, control of gas, or gas quality

Program / Process: Issues involving improvements related to people or business processes, or issues that are raised as a general concern that do not otherwise fit other issue categories.

Records: Issues that consist of inadequate, incomplete conflicting, or unavailable records; issues related to records storage, integrity, classification or storage/protection.

Appendix A, Examples of Issues to Report
Page 2 of 2

Reliability: Issues that may impact the company's commitment to reliability, including dig-ins, unplanned outages, maintenance and asset management.

Safety & Health: Safety related issues such as: near hits, public safety, clearance issues, confined space, electrical safety, excavation safety, fire safety, industrial safety, safety at heights and vehicle safety

Security: Issues related to physical or cyber security

Supply Chain: Issues related to contract administration, warehouse management, suppliers, materials management and purchasing.

Training: Issues or concerns related to company-offered training and/or apprenticeship programs

Appendix B, Other Reporting Solutions
Page 1 of 1

OTHER PG&E REPORTING SOLUTIONS AND PROCESSES

Examples of other reporting solutions for issues that should not be submitted to CAP

- Compliance and Ethics Helpline
- Electric Map Correction Tool
- Facilities Management
- Federal Monitor Hotline
- Human Resource (HR)
- Here to Help Hotline
- Injury
  - 24/7 Nurse Care Line: 1-888-449-7787
  - CareOnSite: 1-888-888-8656
- IT Service / Hardware Requests (SMC)
- Material Problem Reports (MPR)
- Motor Vehicle Incident (MVI)
- Security
- Self-Care
- Spark Idea Marketplace

Appendix C, Quality Closure Criteria for CAP Issues
Page 1 of 2

QUALITY CLOSURE CRITERIA FOR CAP ISSUES

Each month, 100% of high risk issues, 50% of medium risk issues and 5% of low risk issues at a minimum are reviewed for quality closure by the LOB CAP teams. The following section describes the criteria utilized by CAP team members to determine quality CAP issue closure. The criteria are specified in GOV-6101S, "Enterprise Corrective Action Program Standard."

1. Issue is well defined.

   The issue being resolved is clearly stated in the issue description/long text.

2. The extent of condition is considered, if applicable.

   For issues where there is a reasonable probability that the issue exists and poses a risk in other areas, an extent of condition analysis should be performed.

   The extent of condition examines the extent to which the actual condition exists, or may exist, with other equipment, processes, or human performance. The results of this analysis should be documented in the issue description/long text. Justification should be provided if an extent of condition analysis is not conducted.

NOTE
Issues being documented, tracked and managed in another recognized program can be closed to another reporting solution. Closure documentation of the issue should include the name of the program the issue is being tracked in, as well as a traceable reference number generated from the new reporting solution.

3. The issue is not closed to a promise.

   Corrective actions cannot be closed to a future completion target. Actions are considered outstanding until the action has been performed. All corrective actions must be completed at time of issue closure. Completed issues in CAP documenting another company approved solutioning process and unique identifier for tracking is acceptable.

4. Actions taken are clearly documented.

   Actions taken to address the issue should be clearly documented in either the action description field, or in the issue description/long text field. This includes a description of the action, the outcome upon action completion, the position title of the individual performing the action and the date the action was completed. Supporting evidence such as photographs, revised procedures, or other documentation should be attached to the issue.

Appendix C, QUALITY CLOSURE CRITERIA FOR CAP ISSUES
Page 2 of 2

5. Justification is provided if no action is taken.

   If the conclusion of the issue evaluation is that the issue cannot or will not be addressed, provide a detailed explanation and supporting evidence for how this conclusion was reached.

Corrective Action Program Procedure

Appendix D, Closure Documentation Guidance for Corrective Actions
Page 1 of 1

CLOSURE DOCUMENTATION GUIDANCE FOR CORRECTIVE ACTIONS

Closure documentation of corrective actions should have a closure statement that explains what action was taken, and how that action meets the intent and requirement of the corrective action. Document only the actions taken to address the corrective action, DO NOT include information such as additional enhancements not related to the actual corrective action description.

References to records archived should have the complete unique document number of the record in the closure documentation for traceability so it can be retrieved by the reviewer. The closure statement should identify the specific plan, standard, procedure or work order step that implements the corrective action.

Closure documentation, including attachments, entered in CAP should not contain personal or confidential information.

- IF identified, such information will be redacted
- OR the issue marked as "protected" in the CAP system

NOTE

When reviewing the issue or actions for closure, the issue owner should include the CAP issue initiator, if possible, as part of the process to ensure that the actions taken have addressed the issue.

RECOMMENDED OBJECTIVE EVIDENCE FOR CORRECTIVE ACTION CLOSURES

There can be supporting documentation that provides objective evidence that the action was completed as written such as roster sheets, training materials, email communications, project records, procedure excerpts, etc.

Documents provided as objective evidence can be attached in.pdf format to the specific action they satisfy. Documents as objective evidence should contain the following:

- A file name or document title
- Issue number so it is traceable to the issue.
- A scanned copy of the document page(s) with the information highlighted or bubbled.
- Final signatures, approvals and dates.

A draft document is not evidence of closure.

Corrective Action Program Procedure

Appendix E, Gas Operations Minimum Requirements for Cause Evaluations

Team Responsible for Identifying	Gas Operations Minimum Requirements for Cause Evaluations
Safety	• Significant safety observation or finding as deemed by safety leadership
Process Safety	Gas asset damaged or degraded such that it may not meet specifications or fulfill intended purposes, including but not limited to: • At-fault dig-in with gas release • Strength test leak or rupture • Large over-pressurization • Pipeline rupture • Pipeline leak as deemed by Integrity Management leadership • Unplanned loss of gas supply that has significant operational or customer impact • Unintentional gas release resulting in fire or explosion and asset damage (excludes events caused by third party) • Other significant process safety events as deemed by Process Safety Management leadership
Compliance	• Significant compliance concern or environmental impact as deemed by compliance leadership
Quality Management	• Significant quality finding as deemed by Quality Management leadership

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 6

UTILITY PROCEDURE: TD-4014P-04, CHANGE CONTROL PROCESS FOR GAS ORGANIZATIONAL CHANGES, REV. 0B

Minor Revision Guidance Document Analysis (GDA)
Change Control Process for Gas Organizational Changes
TD-4014P-04, Rev: 0b

1. Document Coordinator:	Lily Gharib	**2. Date of Request:**	05/21/2019
3. Change Details			
Section/Step	**What to Change/Add/Delete**		
Effective Date	Update to 08/20/2019.		

4. Reason for the Change
Main drivers and considerations: Align effective date for minor revision with major revision. **Additional info for leadership awareness:** NA
5. Implementation Plan
NA

6. Stakeholder Reviewers		
Name	**Department/Role**	**Review Date**
NA – stakeholder review not needed to correct oversight.		

Schedule & Priority	
7. Priority: ☐ **Regular** *(monthly publication)* ☒ **High** *(Publish within 24 hours of EDRS approval)* Reason (for *High* priority only): Correcting an oversight.	
8. New Effective Date: Align effective date for minor revision with major revision, Rev. 0, 08/20/2019.	
9. EDRS Sequential ☐ **or Concurrent** ☒	
Approvers: Lily Gharib, Kevin Akey, Jerrod Meier, Monica Yankowski	
10. Minor Revision Request Reviewed By	
Supervisor: Jerrod Meier	**Date:** 05/21/2019
11. Document Category	
☐ **Engineering** ☐ **Construction** ☐ **Maintenance & Operations** ☒ **Emergency/Admin**	

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 7

UTILITY PROCEDURE: TD-4014P-05, FIELD DESIGN CHANGE PROCESS FOR DISTRIBUTION LINES AND DUAL-ASSET FACILITIES, REV. 1

Guidance Tailboard

DOCUMENT NAME: Field Design Change Process for Distribution Lines and Dual-Asset Facilities

DOCUMENT NUMBER: TD-4014P-05, Rev. 1

TAILBOARD ISSUED: 10/04/2019 TAILBOARD BY: 11/15/2019

What is changing?

Utility Procedure TD-4014P-01, "Field Change Control Process," has been split into two separate procedures, Utility Procedure TD-4014P-05 and Utility Procedure TD-4014P-06, "Field Design Change Process for Transmission Pipelines and Transmission Station Designs." This new utility procedure describes the process Pacific Gas and Electric Company (PG&E or Company) uses to initiate, assess, evaluate, and document field changes to distribution lines and dual-asset designs issued for construction.

This utility procedure supersedes Utility Procedure TD-4014P-01 and has been revised to provide clarity for personnel in the field, in engineering, in quality management/quality control, and as-builts personnel on requirements to initiate, evaluate, approve, and document field changes to designs for gas distribution and dual-asset facilities during construction.

Why does it matter?

Adherence to the process and documentation of field design change requests, including after the fact (ATF) changes, are an inherent risk. Process controls are administrative and thus rely on the behavior of employees and contractors to ensure the process is followed. Failure to follow the process could lead to unapproved changes to designs and introduction of risk into the system. Adherence to the processes for quality assurance and quality control mitigate this risk by conducting periodic audits of the process to ensure adherence.

Key changes from Utility Procedure TD-4014P-01 include:

- Differentiates document scope for distribution and dual-assets for clarity and ease of use.
- Clarifies requirements for the initiation of the Field Design Change process.
- Clarifies for field personnel the risk and consequences of implementing design changes in the field prior to engineering review and approval.
- Clarifies the requirements for engineering to evaluate, approve/disapprove, and document requested field changes to approve design documents.
- Clarifies how ATF changes (changes requiring engineering review after those changes have been implemented in the field) are documented.
- Integrates field design change into the current work process. Field design changes are now documented in the SAP work order system. Form TD-4014P-01-F01, "Field Change Control Form," and emails to ChangeControl@PGE.com will no longer be used for this purpose.
- Sets requirement to verify that the field design change documentation is in an electronic system for the as-built quality review process.

PG&E

Guidance Tailboard

- Provides information to improve the adherence for monitoring the process, and to track and trend field changes by the as-built process to address internal audit findings.
- Revises process flowchart.

Required Action

This procedure applies to the following personnel; gas distribution engineers and estimators, service planning and design estimators, including applicant design, maintenance and construction coordinators and crew leads, general construction field engineers and crew leads, new business inspectors, and construction management personnel and inspectors.

Tools and Training

Directors of engineering, field construction, and construction management must ensure that this utility procedure is communicated and implemented in their area.

Managers or supervisors of engineering, field construction, and construction management must implement this utility procedure and support their personnel in applying the field design change process.

Timeline

Date	Activity
10/04/2019	Publication date.
11/15/2019	Tailboard by date.
12/15/2019	Effective date.

CPACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 8

UTILITY PROCEDURE: TD-4014P-06, FIELD DESIGN CHANGE PROCESS FOR TRANSMISSION PIPELINES AND TRANSMISSION STATION DESIGNS, REV. 1

Guidance Tailboard

DOCUMENT NAME: Field Design Change Process for Transmission Pipelines and Transmission Station Designs

DOCUMENT NUMBER: TD-4014P-06, Rev. 1

TAILBOARD ISSUED: 10/07/2019 TAILBOARD BY: 11/15/2019

What is changing?

Utility Procedure TD-4014P-01, "Field Change Control Process," has been split into two separate procedures, Utility Procedure TD-4014P-05, "Field Design Change Process for Distribution Lines and Dual Asset Facilities" and Utility Procedure TD-4014P-06, "Field Design Change Process for Transmission Pipelines and Transmission Station Designs." This new utility procedure describes the process Pacific Gas and Electric Company (PG&E or Company) uses to initiate, assess, approve, and document field changes to transmission pipelines and transmission station designs issued for construction.

This utility procedure supersedes Utility Procedure TD-4014P-01. It has been revised to provide clarity for personnel in the field for the process PG&E uses to initiate, assess, approve, and document field changes to transmission pipelines and transmission station designs issued for construction.

Why does it matter?

Adherence to the process and documentation of field design change requests, including after the fact (ATF) changes, are an inherent risk. Process controls are administrative and thus rely on the behavior of employees and contractors to ensure the process is followed. Failure to follow the process could lead to unapproved changes to designs and introduction of risk into the system. Adherence to the process quality assurance and quality control mitigate this risk by conducting periodic audits of the process to ensure adherence.

Key changes from Utility Procedure TD-4014P-01 include:

- Differentiates document scope to transmission pipelines and transmission station facilities for clarity and ease of use.
- Clarifies requirements for the initiation of the field design change process.
- Clarifies for field personnel the risk and consequences of implementing design changes in the field prior to engineering review and approval.
- Clarifies the requirements for engineering to evaluate, approve/disapprove, and document requested field changes to approve design documents.
- Clarifies how ATF changes (changes requiring engineering review after those changes have been implemented in the field) are documented.
- Integrates field design change into the current work process. Field design changes are now documented in the Unifier system using the request for information (RFI) work flow. Form TD-4014P-01-F01, "Field Change Control Form," and emails to ChangeControl@PGE.com will no longer be used for this purpose.

PG&E

Guidance Tailboard

- Sets requirement to verify that the field design change documentation is in an electronic system for the as-built quality review process.
- Provides information to improve adherence, to monitor the process, to track, and to trend field design changes by the as-built process to address internal audit findings.
- Revises process flowchart.

Required Action

This procedure applies to the following personnel; gas transmission pipeline and facility engineers, gas quality control personnel, project engineers, project managers, general construction superintendents, field engineers, foremen, crew leads, construction management employees and inspectors.

Tools and Training

Directors of engineering, field construction, and construction management must ensure that this utility procedure is communicated and implemented in their area.

Managers or supervisors of engineering, field construction, and construction management must implement this utility procedure and support their personnel in applying the field design change process.

Timeline

Date	Activity
10/07/2019	Publication date.
11/15/2019	Tailboard by date.
12/15/2019	Effective date.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 9

GAS DESIGN STANDARD: A-38, PURGING GAS FACILITIES,

REV. 1C

Minor Revision Guidance Document Analysis (GDA)
Purging Gas Facilities
A-38, Rev: 1c

1. Document Coordinator:	Payam Shekari	2. Date of Request:	06/27/2019

3. Change Details

Section/Step	What to Change/Add/Delete
Purge Routing and Segmentation 1 & 2	Changed, "'networked grids, multi legged assemblies, or long laterals **must** be separated / isolated" to "looped networked grids **must** be separated / isolated and multi legged assemblies or long laterals **should** be separated / isolated"
Purge Driving 3 A	Replaced, "If purging through Save-a-Valve, the fitting may be 1/6 of mainline pipe if purge pressure is boosted by 20 psig and if purging plastic pipelines, the inlet/outlet may be ¼ the size of the mainline if purge pressure is boosted by 15 psig." with three new tables that provide information for purging through ½ inch and 1 inch pigtails and 1 & 2 inch save-a-valves.
Attachment 1 Purge Plan Checklist and Examples	Updated to reflect the changes made to the procedure.
A-38-F01 Purge Calculation Worksheet	Updated to reflect the changes made to the procedure.
A-38-JA01 Purge Calculation Worksheet Instructions	Updated to reflect changes made to A-38-F01

4. Reason for the Change

Main drivers and considerations: To allow greater flexibility purging gas systems where the ideal isolation locations are not accessible, and to provide more guidance on purging through save-a-valves and pigtails when the recommended inlet/outlet is less than the recommended 1/3 of the main pipeline.

Additional info for leadership awareness:

5. Implementation Plan

Document coordinator will communicate changes to leadership and transmission clearance teams. Gas Control has 15 webinar workshops scheduled for creating distribution purge plans.

6. Stakeholder Reviewers

Name	Department/Role	Review Date
Tim Scheele	Pipeline Services	06/2019
Jerrod Meier	Standards Engineering	06/2019
Matteo Rossi	DIMP Engineering	06/2019
Roberto Quijalvo	Gas Clearance Coordinators	06/2019
Tony Kennerly	Gas Clearance Coordinators	06/2019
John Gaffney	Gas Clearance Coordinators	06/2019
Benjamin Campbell	GC Transmission	06/2019
Josh Kirtley	GC Transmission Pipeline Field Services	06/2019
Ross Leverett	GC Distribution South	06/2019
Steven Fischer	GC Distribution North	06/2019
Michael Seitz	Asset Knowledge Management (AKM)	06/2019
Erik Kurtz	M&C / Leak / Corrosion- South	06/2019
Ty Turner	M&C / Leak / Corrosion- North	06/2019
Clark Wilmer	Service Planning - Diablo Division	06/2019
John Klavdianos	Service Planning - Bay Region	06/2019

Minor Revision Guidance Document Analysis (GDA)

Purging Gas Facilities

A-38, Rev: 1c

Kevin Salazar	T&D Gas Inspection - Central Coast	06/2019
James Rechtin	Corrective & Compliance	06/2019
Roger Williams	Abandonments	06/2019
Dan Baldwin	CM North Reg GD Inspection	06/2019
Pierre Bigras	Construction Management	06/2019
Ed Wong	WRO Intake	06/2019
Jonathan Collaco	Abandonments	06/2019
Jeff Gravelle	Distribution Portfolio Management & Eng	06/2019

Schedule & Priority
7. Priority: ☒ **Regular** *(monthly publication)* ☐ **High** *(Publish within 24 hours of EDRS approval)* Reason (for *High* priority only):
8. New Effective Date: 07/26/2019. The changes are not adding any new requirements; the changes in this revision are providing more flexibility and guidance.
9. EDRS Sequential ☐ **or Concurrent** ☒
Approvers: Payam Shekari, Tim Scheele, Jerrod Meier
Reviewers (if any):
Cc (if any beyond the default): Lily Gharib, Roberto Quijalvo,

10. Minor Revision Request Reviewed By	
Supervisor: Lily Gharib	**Date:** 06/26/2019

11. Document Category			
☒ **Engineering**	☒ **Construction**	☒ **Maintenance & Operations**	☒ **Emergency/Admin**

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 10

UTILITY PROCEDURE: SAFE-3001P-07, CONTRACTOR SAFETY OVERSIGHT PROCEDURE – GAS OPERATIONS, REV. 5

Pacific Gas and Electric Company®

Contractor Safety Oversight Procedure – Gas Operations

SUMMARY

This utility procedure establishes Pacific Gas and Electric Company (PG&E or Company) gas operations processes for managing the safety of contractors performing work on PG&E natural gas facilities and other applicable standards and procedures referenced in this document. This procedure does not cover the following key elements of contractor oversight:

- Specification adherence
- Quality control
- Final documentation

Level of Use: Informational Use

TARGET AUDIENCE

PG&E personnel who manage and oversee contracted and subcontracted work at PG&E Gas facilities, including work supervisors, inspectors, contract administrators, engineers, and other employees responsible for contractor oversight.

SAFETY

Every PG&E employee is responsible for maintaining the safety of the public, of PG&E team members, and contractors. This utility procedure supports and is governed by SAFE-3001S, "Contractor Safety Standard." Adherence to this standard improves safety by ensuring the following:

a. Contractors and subcontractors are prequalified before performing work and must maintain ISN eligibility (A or B grade) throughout the duration of the project.

b. Contractor safety requirements have been included in the contract.

c. An executed contract is in place before starting work.

d. Safety hazards have been identified, planned for, and mitigated.

BEFORE YOU START

Compare the publication date and version number of this utility procedure with the most recently published electronic version to verify that it is current.

Before completing the instructions and tasks in this procedure, PG&E personnel must read and understand SAFE-3001S and the other reference documents listed.

Read this entire procedure before implementing it.

Contractor Safety Oversight Procedure – Gas Operations

TABLE OF CONTENTS

PROCEDURE STEPS

1 Overview

- This Contractor Safety Oversight Program for gas operations is scalable according to project size and risk.
- Each gas leader must assess the project risk before hiring the contractor and determine the suitable level of oversight.
- Large projects are typically those which are greater than $1 million in contractor costs, more complicated than routine work, or high and medium risk projects.
- Section 7 provides guidance on smaller high or medium risk projects ($1 million or less in contractor costs).
- This procedure is applicable only to contractors performing high and medium risk field work as matrixed in SAFE-3001S.
- Contractors and subcontractors performing low risk work are exempt from this procedure.
- More communication regarding safety concerns is better than less communication.
- See Table 1, "Risk and Oversight Matrix" to analyze differences between work risk levels.

Contractor Safety Oversight Procedure – Gas Operations

Table 1. Risk and Oversight Matrix – Publication Date 8/05/2016

Risk Category	Examples of Work Scopes or Work Activities	Primary Triggers
Low Risk	• Consulting, classroom training • Office engineering, design, inspection (limited to no direct exposure to site hazards) • Project Management Office (PMO) services • Basic landscaping services such as lawn mowing, trimming, and pruning (no trenching) • Material delivery off PG&E premises (Shipping) • Transportation of materials (limited to Material Handling off-site to PG&E premises) • Unarmed security services • DOT Regulated Services • Surveying, field inspections, construction management, engineering, design services that DO NOT include the primary trigger events for higher risk work	• Performs NO work activities covered in the Medium/High risk definitions • Does NOT require ANY of the pre-requisites covered in the Medium/High risk definitions • Does NOT require Occupational Safety and Health Administration (OSHA) safety and health programs to address specific criteria identified below under high and medium risk definitions, including any OSHA required training, to mitigate task and location specific hazards
Medium Risk	• Excavating and trenching under 4 feet (excluding hand digging within 2 feet of depth) • Geotechnical investigation, potholing, drilling, boring, horizontal directional drilling (HDD) • Surveying, field inspection, construction management, engineering, design services that require specialized PPE • Material Handling (on/off loading materials using mechanical electric or pneumatic equipment) • Bulk hazardous chemicals transport and handling • Compressed natural gas (CNG) / liquefied natural gas (LNG) handling	• Requires OSHA safety and health programs, including OSHA required training, to mitigate task and location specific hazards • Work requires advanced or specialized PPE, beyond hard hat, safety boots, safety glasses and reflective vest (Examples: personal fall arrest/restraint system, respirator, SCBA, rubber gloves, ear plugs/hearing protection, Flame Resistant (FR) clothing, Electrical Hazard (EH) boots, Energy Control Locks, Tyvek suit, etc.) • Work requires specialized training, formal training, licensing, certification or qualification (Examples: HVAC, Industrial Lift Truck, Permit Required Confined Space Training, Fall Protection Training, Crane Operator certification, pest control applicators license, FERC/NERC training, HAZWOPPER, etc.) • Work directly exposes contract employee(s) to the hazards associated with the other work
High Risk	• Excavation and trenching beyond 4 feet (includes hand digging) • Heavy equipment operation (crane, fork lift, front loader, backhoe, bobcat, bucket truck, aerial lift, boom lift, skidder) • Underwater diving operations • Aviation operations (helicopter, fixed wing) • Demolition / blasting / explosive work • Utility tree trimming, clearance work, vegetation management • Environmental remediation work, asbestos abatement, hazardous material disposal/treatment/transportation, contaminated soil • General construction activities such as framing, sawing, cutting, welding, boring, blasting, coating, grinding, roofing, commercial painting using specialized equipment, electrical/gas	

	installation, scaffolding, civil • Traffic control flagging • Pesticide, herbicide application • Armed security services • Welding and/or hot tapping of gas lines • Electrical work • Conductor stringing / sagging removal • Fault protection / grounding • Radiological handling activities	(Examples: Suspended load spotters, aggregate haulers where delivery of materials requires material handling or site hazard exposure, heavy equipment is in operation, traffic control flaggers)

2 Roles and Responsibilities

This section describes the roles and responsibilities for the Contractor Safety Oversight Program.

Table 2. Contractor Safety Oversight Program Responsibilities

Table 2 describes PG&E Competent Site Representatives and Qualified Site Representatives.

Personnel	Description	Qualifications	Typical Job Titles	Responsibilities

Contractor Safety Oversight Procedure – Gas Operations

Competent Site Representative	• Personnel filling this role may include, but are not limited, to construction manager, lead inspector, construction supervisor, or construction working foreman.
	• Directors and managers may authorize others (delegates), such as project managers or engineers, to fill the role of a PG&E site representative
	• Ensures that PG&E-specific safety considerations have been communicated to the contractor before implementing the contract work.
		• Capable of identifying existing and predictable hazards in the surroundings or working conditions that are unsanitary or dangerous
		• Has training, knowledge, or experience related to the work to be performed and knowledge of the appropriate mitigation measures for the associated hazards.
		• May have formal training to identify and mitigate hazards associated with specific high-risk activities.
		• Familiar with managing contractor safety for operations
		• Familiar with SAFE-3001S
		• Familiar with SAFE-1005S, "Personal Protective Equipment (PPE) Standard"
		• Familiar with RISK-1002S, "Visitor Access Control Standard"
		• Familiar with Cal/OSHA safety regulations and requirements
			• Inspector (including contract inspectors)
			• Construction and/or maintenance crew lead
				• SELECTS the project team
				• DETERMINES the level of contractor oversight needed. This process includes the:
				  ◦ Scope of work and associated risks
				  ◦ Potential for hazard exposure to anyone on or near the job
				  ◦ Conditions required by SAFE-3001S.
				  ◦ Worksite location
				  ◦ Site access
				  ◦ Environmental stewardship
				  ◦ Available local knowledge regarding operational issues
				  ◦ Other site-specific information
				• In conjunction with the resource manager, the regional construction manager, or supervisor,
				• DETERMINES the size and make-up of the field oversight staff according to the project size and risk level of the project hazards
				• PROMOTES a safe work environment by ensuring that the contractor and the project team, at a minimum, clearly understand the roles and responsibilities related to:
				  ◦ Reviewing drawings
				  ◦ Identifying known hazards
				  ◦ Communicating policies, standards, and procedures applicable to the work
				• PROVIDES timely notification to management and the safety team about any safety issues
				• ENSURES that a thorough initial tailboard is conducted by the contractor using the Site Specific Safety Plan (SSSP) and Job-site Safety Analysis (JSSA)
				• Performs periodic safety observations
				• As a Point of Contact, enters post project or at a minimum annual safety performance evaluations in ISN

Qualified Site Representative	• Same as Competent Site Representative	• Has formal training to identify and mitigate hazards associated with specific high-risk activities • Has formal training in risk evaluation, safety management, and incident cause evaluation per Utility Standard GOV-6102S, "Enterprise Causal Evaluation."	• Inspector (including contract inspectors)	• Same as Competent Site Representative

Contractor Safety Oversight Procedure – Gas Operations

Table 3. Contractor Representatives and PG&E Safety Representative

Table 3 describes the roles and responsibilities of Contractor Representatives and PG&E Safety Representatives

Representative	Description / Responsibilities
Contractor Representative and Contractor Safety Representative	• Safety representative is anyone the prime contractor appoints as responsible for the health and safety of all personnel within the contractor's area of control. • Either representative ensures compliance with PG&E and regulatory requirements specific to a facility, location, and site. • Contractor must review and understand the roles and responsibilities outlined in the contract documents and the contractor's safety plan.

PG&E Safety Representative	• Typically, a member of the Corporate Safety and Health organization or Gas construction organization, (e.g. safety specialist)
	• Responsibilities are outlined in SAFE-3001S and include:
	  • Ensuring required conditions for contractors/subcontractors are communicated to the project team.
	  • Compliance measures are in place.
	  • Support for this activity is typically provided by corporate contractor safety, Gas operations contracts, and/or sourcing.
	• Responsible for performing additional field safety observations independent of the LOB observations as deemed appropriate between the LOB and Corporate Safety and Health
	• Perform assessments on contractors that have been in business less than three years and those that have a significant increase in headcount. Refer to the Contractor Safety Management and Organization process for additional information.

2.1 Project Team

1. The project team may consist of personnel from operations, maintenance, engineering, project management, transmission and distribution (T&D) construction, inspection, or others as needed.

2. ANYONE working on the site has the authority and responsibility to stop work if unsafe conditions develop.

    a. All project team members may view Construction Onboarding Modules 1, 2, and 3 in Veriforce.

3. The project team:

    a. Identifies institutional knowledge of the facilities related to the work.

    b. Provides input in identifying the risks associated with the specific project work.

    c. Identifies applicable PG&E-specific policies and procedures to follow.

    d. Provides engineering review to support safe project implementation.

e. Responds in a timely manner to requests and is accountable for their commitments and deliverables.

f. Clarifies PG&E versus contractor scope.

g. Conducts safety observations in the field.

h. Inputs post project or at a minimum annual safety performance evaluations in ISN.

2.2 Management

1. Gas operations directors, managers, and supervisors in each organization utilizing contractors endorse and support gas operation's application of this utility procedure as well as SAFE-3001S.

2. Additional specific responsibilities include:

   a. Participating in pre-construction safety meetings as appropriate.

   b. Providing an avenue for escalation of safety issues.

2.3 Contractor

1. PG&E contractors are responsible for their Site-Specific Safety Plans (SSSPs) or Programmatic Safety Plans (PSPs) and safety processes.

2. Safety may not be compromised for any reason at any time.

3. Contractors shall appropriately identify, analyze and communicate known or potential hazards to their employees, other potentially impacted workforces, and the public (when present), prior to commencing work.

4. Contractors must maintain effective oversight of work crews, including performing safety observations to ensure compliance with PG&E and regulatory safety requirements for their employees and subcontractor work forces under their direct control.

   a. Ensure that all of their subcontractors (at any tier) meet PG&E pre-qualification criteria and have achieved a pre-qualification status through ISN prior to performing any PG&E work.

   b. Perform safety observations, at a minimum of one per week, and document for all crews or projects working for PG&E. For work occurring more than one week, observations should be performed on a weekly basis. For work occurring less than one week, observations should be performed on an as-needed basis as determined by the Line of Business representative.

   c. Ensure all identified safety deficiencies are corrected and properly tracked to closure in a timely manner.

   d. Ensure all safety incidents, including Serious Safety Incidents or Serious Injury and Fatality (SIF) incidents are reported to PG&E immediately.

5. Contractor must aim for zero safety-related incidents, including, but not limited to the following:
   a. Zero Notices of Violations (city, county, state or federal environmental regulations)
   b. Zero motor vehicle incidents
   c. Zero public safety-related incidents
   d. Zero injuries to personnel working at the site that result in a Recordable Incident or Lost Work Day
   e. Zero gas dig-ins, gas releases, or interruptions of service
6. Contractors must ensure all their employees and subcontractor personnel understand that they:
   a. Have the authority to “Stop Work” due to any unsafe work processes or hazards or sub-standard quality work.
   b. Will not, in any way, adversely affect the requestor’s work status or job security (i.e., they will be protected from any/all potential retribution) for stopping work.2.6 (continued)
7. The contractor’s SSSP or PSP must fulfill PG&E safety program requirements cited in the Master Service Agreement and CWA Safety Documents, including, but not limited to:
   a. MSA Specification #13024 (March 15, 2009)
   b. MSA Attachment 2-General Conditions (June 22, 2009)
   c. Safety document titled “Excavation Procedures for Damage Prevention – TD-4412P-05” (if excavating)
   d. Safety document titled “Site-Specific Safety Plan” or “Programmatic Safety Plan”
8. A SSSP or PSP must be completed by High Risk Contractor. SSSPs are for large contractor projects with limited PG&E oversight. PSPs are for contractors typically working as a sub-contractor to a PG&E crew performing routine tasks.
9. All contractors are required to provide training to their employees and subcontractors on the approved safety plan.
   a. Validate workers have completed the Contractor Safety Program Orientation SAFE-0101 and any specific LOB required safety orientations before performing work for PG&E.

10. Perform safety observations, at a minimum of one per week, and document for all crews or projects working for PG&E.

11. Contractor may only mobilize or start work until AFTER:

    a. Submitting an SSSP or PSP to the appropriate PG&E construction or maintenance and construction (M&C) and to the Gas construction safety department management teams per instructions in the "Submittals" paragraph of the Project Specific Information section of the contract

    b. The SSSP or PSP has been reviewed and approved by PG&E's construction or M&C and safety department management teams.

12. Should a safety incident occur, the contractor must notify PG&E staff **in the following order:**

    a. Construction manager/On-site PG&E Person in Charge (Supervisor or Foremen)

    b. Regional construction manager (if applicable)

    c. Gas division safety manager

    d. Safety Specialist

    e. Project manager

13. IF the contractor has any questions regarding PG&E safety procedures and/or safety requirements, THEN the contractor must contact the PG&E construction or M&C representative for guidance and clarifications.

14. PG&E's primary point of contact (POC) for both technical and safety-related matters must be the PG&E construction manager, or the appropriate general construction (GC) or M&C representative.

15. The contractor must maintain records at the job site as described in the SSSP.

16. SSSP Submittal Requirements:

    a. SSSP must be submitted and approved prior to start of the work in the field.

        - Instructions for uploading safety plans and downloading PG&E safety requirement documents from the Unifier system are defined in PSI Attachment entitled "Access Instructions for PG&E Unifier Document Management System."

    b. Contractors will brief all their personnel and sub-contractors on the SSSP and required mitigation methods, including updating same personnel on all plan changes.

    c. Continuously update the SSSP throughout the course of the project, as required, to identify new hazards and incorporate new safety-related activities.

d. All costs associated with mitigating site safety hazards and implementing required safety requirements per the SSSP must be included in the contractor's project proposal price.

17. PSP Submittal Requirements:

a. PSP must be submitted and approved prior to start of the work in the field.

- ISN will send all High-Risk Contractors a PSP template that must be uploaded to ISN for PG&E review.

b. PSP will include Leadership commitments, contact information; typical hazards associated with their work and mitigation measures to address the hazards.

c. PSP must be reviewed and approved on an annual basis by the department that uses the contractor the most.

18. The PG&E Safety Department staff will:

a. Periodically check to ensure job sites are safe and to verify that the contractors are adhering to their approved SSSP or PSP.

b. PG&E Safety Representative shall audit at least 20% of the current High Risk contractors annually to ensure their SSSP or PSP is approved and work being performed is covered in the document under hazard mitigation section.

c. Provide the contractor's management team with a site inspection summary that includes a list of any safety program shortcomings noted during the site check.

d. The summary will include guidance regarding corrective and preventive actions the contractor must immediately implement to correct noted shortcomings.

19. The contractor must:

a. Include comprehensive incident analysis with corrective and preventive action report.

b. Notify the PG&E Safety Management team, in writing, when all required actions have been completed.

c. Contractors' required reporting of significant safety-related incidents/events is shown in Table 4.

Table 4. Safety-Related Event Reporting Timelines

○ Safety-Related Event	○ Verbal Reporting Time Deadline	○ Written Report Deadline
Death/Injury of site workers or public person	Immediately	24 hours
Near-Hit Incidents	24 hours	24 hours
Gas Line Strike or Damage	Immediately call Gas Control [redacted]	24 hours

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	[redacted]	
○ Discovery and Mitigation Methods of Newly Identified Site Hazards	72 hours	5 work days
Damage to Public or Private Property	Immediately	24 hours

20. The prime contractor is responsible for any work done over due to contractor or sub-contractor negligence, unsafe work procedures, or faulty materials/workmanship.

21. The contractor must write emergency plans, if applicable to the work, to cover actions required for:

    a. Emergency Medical Care
    b. Excavation/Trench Rescue (i.e., “Cave-Ins”)
    c. Confined Space Plan
    d. HAZMAT Spill Response Plan

22. Each of above emergency plans must meet federal, state, and local requirements.

23. Emergency plans for items (b), (c), and (d) above will be kept at the contractor’s on-site office for review by PG&E management staff.

24. Site emergency plans must include the names and contact information for key contractor and PG&E personnel as shown in the PG&E site safety plan format.

25. Stop Work Authority

    a. Any PG&E or contractor employee on any project site is granted the right to stop any unsafe or sub-standard quality work.
    b. This stop work authority must be clearly communicated to every worker via the onboarding process.

> NOTE
>
> Contract Precedence—Conflict in Safety Requirements.
>
> Any PG&E safety requirements cited in the Project-Specific Information sheet or Unifier System Safety Requirement documents supersede those in the MSA agreements.

2.4 Line of Business

1. For work performed by a contractor, the LOB shall:

a. Require the contractor provide a safety plan for high risk work (and some LOB-identified medium risk work) that fully addresses the scope-specific work to be performed.

b. Monitor the work and conduct safety observations entering them into the SafetyNet tool (frequency defined in the LOB oversight procedures).

2. PG&E LOB contractor oversight procedures will:

a. Provide guidelines for: determining the level of contractor oversight; establishing the frequency of safety observations; and, entering observations into SafetyNet.

b. Ensure a schedule is developed for safety observations prior to beginning medium and high-risk work activities.

c. Ensure that contractors provide the appropriate levels of safety oversight for their work and that of their subcontractors at any tier.

d. Ensure that PG&E will provide the appropriate level of safety observations for all contracted work including subcontracted work that is geographically remote from their primary contractor.

e. Address when PG&E will assign its own onsite safety personnel.

f. Require annual (at minimum) Contractor Safety Forums with their prime contractors that have active multi-year agreements. Agenda must include PG&E specific safety topics, sharing lessons learned, and performance feedback.

g. Be approved by the respective LOB Director Sponsor for Contractor Safety and the Corporate Contractor Safety team initially, and for any procedure revisions to ensure alignment with the requirements herein.

h. Define the process for the LOB to actively monitor the ISNetwork (ISN) status for contractors and subcontractors, including verification that primes and subcontractors are ISN prequalified prior to the commencement of work.

- Define the process for contractor performance evaluations submitted into ISN for every contractor that is performing active work during the course of the given year.
- Define the process for the LOB to actively monitor the ISN status of their contractors and subcontractors that ensures compliance with ISN badging requirements.
- Define requirements for scanning ISN badges to field-verify contractor prequalification and required employee training, including how the LOB will utilize the ISN badge scanning to field-verify contractor prequalification and required employee training.

i. Define a process for providing contractor work schedules to Corporate Contractor Safety.

3. LOB Operations Field Personnel

    a. Perform and document field safety observations to verify contractor compliance with PG&E and regulatory standards, rules, and codes.

        - Field safety observation frequencies shall be determined by the LOB based on the risks associated with the SOW.

    b. Perform additional field safety observations independent of the LOB observations as deemed appropriate between the LOB and Corporate Safety and Health.

4. Coordinate with Corporate Safety and Health, which perform additional field safety observations independent of the LOB observations as deemed appropriate between the LOB and Corporate Safety and Health.

3 Managing Contractor Safety on Larger Projects (> $1M in Contractor Costs)

3.1 Pre-Construction

1. Contract management (CM) (see SAFE-3001S, Sections 2.2. through 2.26)

    a. Creates a well-defined scope of work to aid with job hazard assessments.

    b. Supports supply chain personnel OR an authorized PG&E procurement representative to evaluate and select contractors, based on pre-qualification requirements in SAFE-3001S.

    c. Partners with safety representative OR a third-party expert to establish PG&E requirements, regulatory requirements, and control measures to eliminate or mitigate hazards specific to the job before starting work.

    d. Verifies that contractors have:

    e. Completed PG&E's pre-qualification process before starting work. In emergency/emergent work situations (see SAFE-3001S, Section 4).

    f. Established criteria to meet or exceed PG&E's minimum field oversight expectations (see SAFE-3001S, Appendix A, "Risk and Oversight Matrix") and have also completed PG&E's pre-qualification process before starting work.

    g. Partners with supply chain personnel OR authorized PG&E procurement representative to submit a Governance Request for contractors/subcontractors that **do not** meet PG&E's pre-qualification safety criteria (see SAFE-3001S).

2. Gas Operations PMO, Construction Management (CM), and Contracts in collaboration with sourcing ASSIST in determining the type of contract, identifying vendors, scheduling, and developing the contract package.

NOTE
The steps required to ensure a safe work environment vary depending on the unique circumstances of each job. Factors to consider include: Work scope Location Available knowledge Potential exposure and risk associated with the work and PG&E assets

3. The project team completes the following pre-construction activities:

   a. Defines the scope of work and the applicable PG&E policies, procedures, standards, permits, and drawings for inclusion in the contract package.

   b. Issues and utilizes the following documents to oversee the contract work:

   c. Discipline-specific "Contractor Safety Checklists" (Attachments 1 – 6)

   d. Confirms if any proposed contractors or subcontractors have conditional approval to perform work per SAFE-3001S .

   e. Provides applicable conditions for approval per SAFE-3001S to site representative before starting work.

   f. Ensures an SSSP is developed and available to the site representative before starting work.

NOTE
Items (1) and (2) below are not all-inclusive nor do they replace the contractor's own safety program. PG&E may share safety information with a contractor to protect PG&E personnel, contractor employees, the general public, and property from injury and damage. Contractors are independent agents and must plan and conduct the work to safeguard persons and property.

   g. The discipline-specific JSSA/SSSP must be filled out and communicated at a tailboard with the contractor and PG&E employees involved in the work before starting physical work.

   h. The SSSP identifies potential hazards or issues that could be encountered in performing the work.

4. Contractors are responsible for the following:

   a. Safely performing work.

      PG&E remains responsible at all times for ensuring compliance with applicable California Public Utilities Commission safety rules and regulations.

b. Before contractors or subcontractors start work on PG&E facilities, the PG&E site representative must confirm that the contractor and subcontractors have completed the following:

- All contractor employees and their sub-contractors have completed and passed Contractor Onboarding Modules 1.0, 2.0, and 3.0 in Veriforce.
- A contractor SSSP has been submitted to and accepted by PG&E, which includes, at a minimum, the following:
    - Plan to implement all work in accordance with all local, state, federal, and PG&E-specific safety regulations.
    - Before starting work, contractors must identify work tasks, associated hazards, and actions to be taken by the contractor to prevent injuries.
    - Contractor is required to communicate and ensure adherence to applicable policies, standards, procedures, specifications, drawings, and conditions of the contract.
    - Plan to immediately notify the PG&E site representative of any injury or medical emergency that occurs while on PG&E property.
    - Contractor must provide a written incident report within 24 to 72 hours including a causal analysis as defined in this document.
- Prior to commencement of work, the PG&E safety representative and PG&E site representative:
    - Review the adequacy of the safety plan, including contractor safety personnel qualifications where applicable.
        - The safety plan approver should have a minimum of 5 years of experience with the scope of work to be performed, their hazards and controls; AND the minimum of Cal/OSHA 10-hour Construction Industry training course.
    - Perform a safety assessment to evaluate whether additional safety mitigations are required.
    - IF the project team determines that additional expertise is required,
    - THEN PG&E will engage third-party experts to perform the analysis.

5. Hazard Communication – Work-site Awareness

a. All visitors, contractors, sub-contractors, PG&E employees and members of the public shall be informed of hazards before the commencement of work.

3.2 Pre-Construction Safety Meeting/Safety Kick-Off

1. For all major construction projects that are led by an outside contractor, the PG&E site representative will participate in the pre-construction safety meeting before a contractor mobilizes to the project site.

   a. Meeting includes the PG&E project team that is responsible for contractor oversight.

   b. Contractor keeps and manages sign-in sheets for this kick-off meeting. The attendees for this meeting include the following:

      - Contractor and their sub-contractors
      - Project manager
      - PG&E site representative
      - PG&E safety specialist
      - Area project engineering supervisor
      - Representative from PG&E's Corporate Contractor Safety group (optional)
      - Director of project execution and the manager of project engineering (optional)

   c. The agenda for the kick-off meeting must include, but is not limited to:

      - Reviewing the daily JSSA requirements.
      - Discussing roles and responsibilities for each team member.
      - Discussing construction safety risks and how they will be mitigated.
      - Reviewing and verifying a communication plan relative to safety.
      - Creating field work notifications and an emergency response plan.

4 Construction

4.1 Construction Oversight

1. The PG&E site representative:

   a. Observes the contractor's adherence to contractor's safety plan, daily JSSA, and general safe practices.

   b. IF the PG&E site representative OBSERVES unsafe practices or a violation of the contractor's safety plan or JSSA, THEN the PG&E site representative STOPS the activity or all work on the project if necessary, until the contractor develops and implements corrective actions and communicates corrective actions to the on-site team.

NOTE

It is everyone's responsibility to escalate a safety concern if they believe corrective actions have not properly addressed safety concerns.

c. Communicates the safety issue per PG&E's safety reporting requirements.

d. Actively participates in the daily tailboard meetings led by the contractor to ensure that:

- Safety is planned for the day.
- The contractor's JSSA addresses all foreseeable hazards associated with the activities planned for the day.
- The discipline-specific SSSP is used as a reference to identify potential hazards that must be addressed.
- Changed conditions are identified and addressed in the contractor's safety plan.
- Best practices are discussed and incorporated.

e. Acts as the sole representative of PG&E on site in relation to all matters of public and worker safety, as well as quality of work.

f. Interfaces with agencies, government representatives, other utilities, local communities, businesses, institutions, customers, first responders, and law enforcement representatives.

g. Ensures compliance with all permit conditions.

h. Can be a PG&E employee or consultant/contractor hired by PG&E to represent PG&E on site.

i. In a case of an emergency arising on site, the PG&E site representative immediately assumes command of the incident and becomes the incident commander (IC) managing the incident until relieved by Operations Emergency Center (OEC) personnel. As such, the PG&E site representative will initiate all appropriate actions listed in the Gas Emergency Response Plan (GERM) to ensure workers' and public safety.

j. Wears PG&E branded Personal Protective Equipment (PPE) at all times to ensure they are easily and readily identifiable by first responders, law enforcement agencies, other utilities and local government as the PG&E representative on site. This requirement applies to PG&E employees and consultants/contractors (i.e. inspectors or construction managers) hired to represent PG&E on site.

4.2 Field Safety Observations

1. The worksite team participates in periodic field safety observation to be supported by the PG&E safety representative.

2. The PG&E site representative notifies the PG&E safety representative of the project construction schedule before construction begins.

3. The PG&E safety representative:

    a. Develops the field safety observation criteria.

    b. Ensures observations are performed in accordance with the set frequency. Refer to the table below:

Field Safety Observations – Frequency Requirements		
Risk	**Work Description**	**How Often?**
High*	• Tasks that meet the criteria for high risk per Table 1 Risk and Oversight Matrix.	1 per week
Medium**	• Tasks that meet the criteria for medium risk per Table 1 Risk and Oversight Matrix.	1 per month

* A minimum of ONE observation per week will be required for ANY (not each) of the High-Risk Gas Contractors for a total number of documented safety observations on High Risk Contractors of 52 per year.

** A minimum of ONE observation per month will be required for ANY (not each) of the Medium Risk Gas Contractors for a total number of documented safety observations on Medium Risk Contractors of 12 per year.

Gas will therefore perform and document a minimum total number of safety observations of 64 per year as detailed above.

4. After completing the field safety observation, the PG&E site representative and the PG&E safety representative REVIEW the results of the field safety observation with contractor's site representative.

5. PG&E may require the contractor to develop an action plan to address any field safety observation issues, especially if they are significant or systemic issues.

6. The contractor site representative CAPTURES best practices and SHARES them with the contractor team for implementation.

7. The PG&E safety representative DOCUMENTS the contractor's completion of action items resulting from the field safety observation.

5 Post-Construction

1. The PG&E site representative ENSURES that the Contractor Performance Evaluation Form is completed for major projects and is uploaded to Unifier.

    a. The form must be completed in a timely manner at the completion of construction activities on major projects, or annually for multi-year projects.

2. Post-construction lessons learned meeting is conducted and documented in Unifier on major projects.

3. All contractor performance must be entered into ISN. The frequency is determined by the business unit, but must be done annually at a minimum.

6 Documentation

1. The PG&E safety representative collects all safety related documentation and includes it in the final inspection report to be filed on the shared drive and Unifier.

2. The final safety-related documentation must include, but is not limited to, the following:

   a. Site Specific Safety Plan
   b. Documentation of all certifications and qualifications for site personnel
   c. Safety incident analysis reports
   d. Safety Quality Good Catch Forms (near- hit)
   e. Daily tailboards and JSSAs
   f. Field safety observation documentation
   g. Contractor Project Specific Performance Evaluations (see Attachments 5, 6)

3. The PG&E safety representative ENSURES that the appropriate safety-related documentation is properly filed.

4. Recordkeeping

   a. Retain records per the record retention schedule.

7 Monitoring ISN Status and Scheduling Requirement

The process for the LOB to actively monitor the ISN status of contractors and subcontractors, and for sharing schedules, is as follows:

7.1 Active Contractors/Vendor Determination

1. A Purchase Order (PO) report is requested by the LOB.

2. The Master Compliance Report Status Excel is updated, adding a new row for the date of the most recent PO.

3. In the new PO column, dates are updated for all contractors listed on that recent PO.

   a. Contractors that have not been listed on a PO for over 18 months are no longer considered “Current Gas Ops Vendors” and are screened and removed from weekly review.

b. Contractors that directly respond and say they are no longer performing work for PG&E, or do not expect to perform work in the next 18 months, are also manually removed from the "Current Gas Ops Vendors" list.

7.2 ISN Grade

1. A custom report, named "Contractor Update – GAS," is run through ISN. The report pulls all Gas High Risk and Medium Risk contractors in ISN.

2. The Master Compliance Report Status Excel is updated, adding a new row for the most updated grades.

3. Grades from the previous report are compared for each contractor. Contractors with grade changes (drops) are monitored on a weekly basis or until they return to an "A" or "B" grade.

4. If a contractor loses their pre-qualified status (i.e., their ISN grade drops below a "B") during the course of the contract, the LOB representative will evaluate if the contractor can return their grade to an acceptable status. If not, then the contractor's work must be completed within 30 days of the negative grade change, or an approved variance must be granted as is required in the Contractor Safety Standard SAFE-30001S and the Contractor Safety Variance Procedure SAFE-3001P-11.

5. A LOB representative receives daily emails from ISN containing push reports. These reports outline changes in contractor grades and the reason behind the grade change. The LOB representative then directs this information to the Contractor Management Team.

7.3 ISN Badging

1. A report named "PG&E ISN ID Card Report" is generated by the LOB, distinguishing data for prime contractors and all contractors.

2. A pivot table is used to edit this report and show active contractors that have not requested ISN ID cards.

3. The Master Compliance Report Status Excel is updated, adding a new row for the most updated badging status.

4. Badging statuses from the previous report are compared for each contractor, with noted variances adjusted for contractors utilizing printed and laminated badges. Contractors with status changes (to Not Submitted) or that have not requested badges are monitored on a weekly basis or until they return to a completed status.

7.4 ISN Training (SAFE-0101)

1. An Online Training Report is ran separately for Gas High Risk and Medium Risk contractors in ISN for the following SAFE-0101 Trainings:

   a. Corporate Contractor Safety Orientation (SAFE-0101)

b. Esp Corporate Contractor Safety Orientation (SAFE-0101)

c. Updated Esp Corporate Contractor Safety Orientation (SAFE-0101)

2. The reports are combined to one report with all High and Medium Risk contractors. A pivot table is used to edit this report and calculate the percent completion of each individual contractor.

3. The Master Compliance Report Status Excel is updated, adding a new row for the most updated completion percentages.

4. Percentages from the previous report are compared for each contractor. Contractors with percentage changes (drops) or those that remain at below 100% completion are monitored on a weekly basis or until they return to 100% completion.

7.5 Completed Programmatic Safety Plans (PSPs)

1. A custom report, named “Gas – High Risk PSP Report” is run through ISN. The report pulls all Gas – High Risk contractors in ISN.

2. The Master Compliance Report Status Excel is updated, adding a new row for the most updated PSP status.

3. PSP statuses from the previous report are compared for each contractor. Contractors with status changes (to Expired or Rejected) are monitored on a weekly basis or until they return to an Accepted status.

7.6 Uploading of Project Schedules to Corporate Contractor Safety Sharepoint

1. Schedules are uploaded by a project team member from GPOM and LNG/CNG through the LOB Project Schedule link on the Corporate Contractor Safety Sharepoint no later than the 5th business day of each month.
   a. Instructions for uploads can be found here.

2. P6 Schedules are shared directly to Corporate Safety for Reservoir Engineering, Distribution, and Transmission projects.

8 Managing Contractor Safety on Smaller Projects (< $1M in Contractor Costs) or Sub-Contractors supporting Maintenance and Construction Operations

8.1 Minimum Requirements

1. On smaller projects, the Gas responsible leader (director, manager, superintendent, and supervisor) overseeing the work ensures the following minimum requirements are met:

   a. The scope of work is clearly defined for all parties through the Contract Work Authorization (CWA) or Blanket Purchase Order (BPO).

   b. Qualified, trained contractors are selected.

c. Safety hazards are identified and communicated effectively between all parties involved through a tailboard or review of the contractor's PSP.

d. Contractors develop, implement, and adhere to comprehensive safety plans that address the unique challenges of working on PG&E's natural gas facilities.

e. Proper job safety oversight is provided.

8.2 Specific Requirements

1. The responsible Gas leader reviews each project to determine the specific level of oversight according to project risk.

> NOTE
>
> All of the processes and forms used for larger projects may also be used for smaller projects. Variations of these forms may be used to document risk identification and mitigation measures and to demonstrate that all of the above minimum requirements (Section 6.1, 1 through 5) have been met.

2. At a minimum, the responsible Gas leader ensures the following:

   a. The job scope is understood by all parties.

      - The contractor's scope of work is clearly defined, including distinguishing between contractor's responsibilities and PG&E's responsibilities.
      - The contractor's field supervision clearly understands this scope of work prior to start of contractor field activities.
      - The scope of work must be clearly communicated and understood as part of project kick off meeting if one occurs or at a minimum as part of the JSSA.

   b. Qualified, trained contractors are selected.

      - Only PG&E approved contractors may perform the work.
      - This requirement specifically includes contractors with an acceptable status in ISN and Gold Shovel Program (if contractor performs excavation activities).
      - Governance may be required for contractors with sub-par grades in ISN or Gold Shovel.

   Safety hazards are identified and communicated effectively to all parties involved. This includes specifically holding a project kick off meeting or, at a minimum, a JSSA and tailboard, to review:

      - The project scope of work.
      - All hazards associated with the work.
      - Permit conditions.

- Applicable PG&E safety policies.
- The PG&E SSSP, if one has been prepared for the project.
- The emergency response plan

c. Place special emphasis on:

- The right and obligation to stop unsafe work.
- Requirements for completing and documenting a JSSA and holding safety tailboards with the entire job crew on a daily basis, at the start of the shift, or more frequently whenever conditions change. **NOTE**: For contractors transporting hazardous materials (for example, LNG/CNG), refer to attachment 7 for guidance.
- The requirement to keep records of all projects and JSSA/safety tailboards and make them available to PG&E if requested.
- An emergency response plan for each project, including providing closest medical facility and jobsite address. This notification may take the form of a white board placard on the back of a crew truck.
- The obligation to report all safety incidents as outlined in Table 3 above including Attachment.4, “Incident Report Form.”
- The requirements of the “Emergency Notification,” process (Table 4) and the communication of Gas Control Emergency phone numbers for reporting any dig -ins or gas leaks.
- The requirement that appropriate personnel on-boarding is completed and documented as determined by the responsible Gas leader. This can include a kick-off project tailboard to on-board contractors. On-line on-boarding, a video or job-walk prior to the start of work are all acceptable means of on-boarding a contractor to discuss the specific hazards associated with the project or task.

d. Contractors:

- Develop, implement, and adhere to comprehensive safety plans that address the unique challenges of working on PG&E’s natural gas facilities.
- Conduct a JSSA and safety tailboard with all construction personnel at a minimum once daily at the beginning of every shift or whenever conditions change.
- Retain all projects’ JSSAs/safety tailboards onsite during the project and for a minimum of 36 months after the project is completed. These records will be made available to PG&E personnel whenever requested.

3. Ensures proper job safety oversight is provided.

a. The responsible Gas leader:

- Provides adequate job safety oversight depending on project risk and duration
  - This oversight may include, as needed, full time safety oversight or may include regular, spot, or random individual jobsite, job bundles, or program visits as determined on a case by case basis.
- Visits worksites and performs regular or randomized safety observations suitable for the work performed. At a minimum, these observations ensure:
  - Adequate JSSAs are completed daily/per shift and are followed by the contractor(s). **NOTE**: For contractors transporting hazardous materials (for example, LNG/CNG), refer to attachment 7 for guidance.
  - All applicable safety policies are being followed, including Cal/OSHA and PG&E policies as well as the SSSP if one exists.
  - An excavation competent person is on site 100% of time anytime excavation work is being performed or personnel are working inside excavations.
  - The field visit and safety observation is documented in a suitable tool. PG&E Guardian tool, Attachment 4, or other suitable tools may be used for this purpose.
  - A suitable Contractor Performance Evaluation (Attachment 5) is conducted, documented, and shared with the contractor at the end of each project or group/bundle of small jobs or other suitable interval.
  - For groups of smaller jobs, one contractor evaluation per region per quarter is suggested.
- Verifies an adequate emergency plan exists.
- Confirms that field employees understand the emergency plan

9 Managing Transportation of LNG/CNG or other Hazardous Materials

1. Projects over or under $1M apply to LNG/CNG operations. Section 8 pertains to the oversight requirements related to transporting LNG/CNG to worksites and other locations.

2. Requirements for completing and documenting a JSSA and conducting a tailboard are required for all transport operations. For more details refer to attachment 7 – JSSA Matrix for LNG/CNG transportation operations.

END of Instructions

DEFINITIONS

3. **Causal Analysis** – An evaluation of all factors that contributed to an incident. There may be one or more causal factors, and each factor must be analyzed to determine why that causal factor occurred. Elements that may be considered include, but are not limited to the following: personnel/staffing, leadership, equipment, environment, policies, and procedures. A causal analysis does not necessarily lead to a single root cause, but should generate corrective actions to address each causal factor.
4. **Competent Site Representative –** A designated individual, typically a supervisor or regional construction manager, authorized to make decisions impacting safety, schedule, production, and project costs.
5. **Contractor –** A company directly hired by PG&E to complete a specific scope of work or service. Throughout this document, references to contractor include all subcontracted resources.
6. **Contractor Site-Specific Safety Plan (SSSP) –** Detailed safety plan created by the contractor to eliminate or mitigate specific job site environmental, health, and safety hazards associated with the scope of work. In this document, the SSSP is referred to as the "contractor safety plan."
7. **High Risk Contractors –** Contractors or subcontractors performing work that directly exposes their employees to PG&E systems, assets, or processes associated with Power Generation, Gas or Electric transmission or distribution operations. This term also includes contractors whose work requires any of the following:
   - Bodily entry into a confined space or hazardous environment.
   - Applying lockout/tagout (LOTO) devices as part of hazardous energy control
   - Working at a height that requires the use of fall arresting equipment
   - Entering an excavation greater than 4 feet deep
   - Demolition activities
   - The use of explosive devices
   - Commercial diving
   - Aviation services
   - Vegetative management beyond weed control
   - Handling or transporting hazardous chemicals.
8. **Job-Site Safety Analysis (JSSA)** – Identifying hazards, evaluate and prioritize the hazards for control, select appropriate controls, and evaluate the controls for any given job task to improve work practices and promote a safe work environment.

   Low-Risk Contractor – Contractors or subcontractors NOT working on or exposed to any hazards associated with Power Generation, Gas or Electric transmission or distribution processes or process-related equipment or working within designated construction areas. These contractors are exempt from this utility procedure and its standard. Work requires minimal planning, preparation, formal training, or work controls.

9. **Medium Risk Contractor–** Contractor whose work requires advanced planning, preparation, formal training, work controls, and audit/oversight, or specialized personal protective equipment (PPE) beyond hardhat, safety glasses, safety toed footwear or high visibility vests. Contractors or subcontractors that do NOT meet the definition of high or low risk

10. **Near-Hit –** An unplanned event that did not result in injury to employees, contractors, or the public, and did not result in damage to Company assets
11. Examples of near hits include potential
    - Disruption of service
    - Personal safety or hazardous conditions, such as driving
12. **PG&E Safety Representative –** PG&E individual recognized by degree, certification, knowledge, or experience as a health and safety subject matter expert (SME) who has decision-making authority for ensuring safety compliance.
13. **Responsible Gas Leader –**The PG&E Gas director, manager, superintendent, supervisor, or his delegate who the work is being performed for and/or who has been appointed to oversee the work.
14. **Safety and Quality Good Catch –** A proactive approach to identify safety or quality issues that include stopping any unsafe or non-quality work or activity and coaching a fellow team member
15. **Safety Prequalification Contracted Administrator -** ISNetwork is the contracted vendor that was previously referred to as a third-party vendor
16. **Stop Work –** Deliberate act of stopping work to eliminate or effectively control unsafe work or sub-standard quality work, practice, or behavior.

IMPLEMENTATION RESPONSIBILITIES

17. Directors and managers/ superintendents in Gas operations are responsible for communicating and implementing this procedure within their respective organizations and for ensuring it is being adhered to going forward.

GOVERNING DOCUMENT

18. SAFE-3001S, "Contractor Safety Standard"

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

19. Cal/OSHA Title 8 Regulations

REFERENCE DOCUMENTS

20. **Developmental References:**
21. Cal/OSHA Form 301, "Injury and Illness Incident Report"
22. LAW-2001S, "Contracting Requirements Standards"
23. PG&E's *Code of Safe Practices*
24. PG&E's Hazard Reference Guide for Contract Work
25. PG&E's *Procurement Manual*
26. SAFE-1001S, "Safety and Health Program Standard"

Contractor Safety Oversight Procedure – Gas Operations

27. TD-4412P-05 – Excavation Procedures for Damage Prevention
28. **Supplemental References:**
29. N/A

APPENDICES

30. Appendix A, "Process Map"

ATTACHMENTS

31. Attachment 1, "Site Specific Safety Plan Template"
32. Attachment 2, "Incident Report Form
33. Attachment 3, "Good Catch/Quality Catch/Near Hit"
34. Attachment 4, "Sample Safety Checklist/Observation Form"
35. Attachment 5, "Sample Contractor Project Specific Performance Evaluation in Unifier"
36. Attachment 6, "Job Aid for Completing Gas Contractor Safety Evaluation in ISN"
37. Attachment 7, "Sample Lessons Learned Form"
38. Attachment 8, "JSSA Matrix for LNG/CNG transportation operations"

DOCUMENT RECISION

39. NA

DOCUMENT APPROVER

40. Kcammee Vreman – Director, Safety, Quality and Contracts

DOCUMENT OWNER

41. John Gilginas, Manager – Gas Workforce Safety

DOCUMENT CONTACT

42. Pierre Bigras, Director – Construction Management
43. John Gilginas, Manager – Gas Workforce Safety

REVISION NOTES

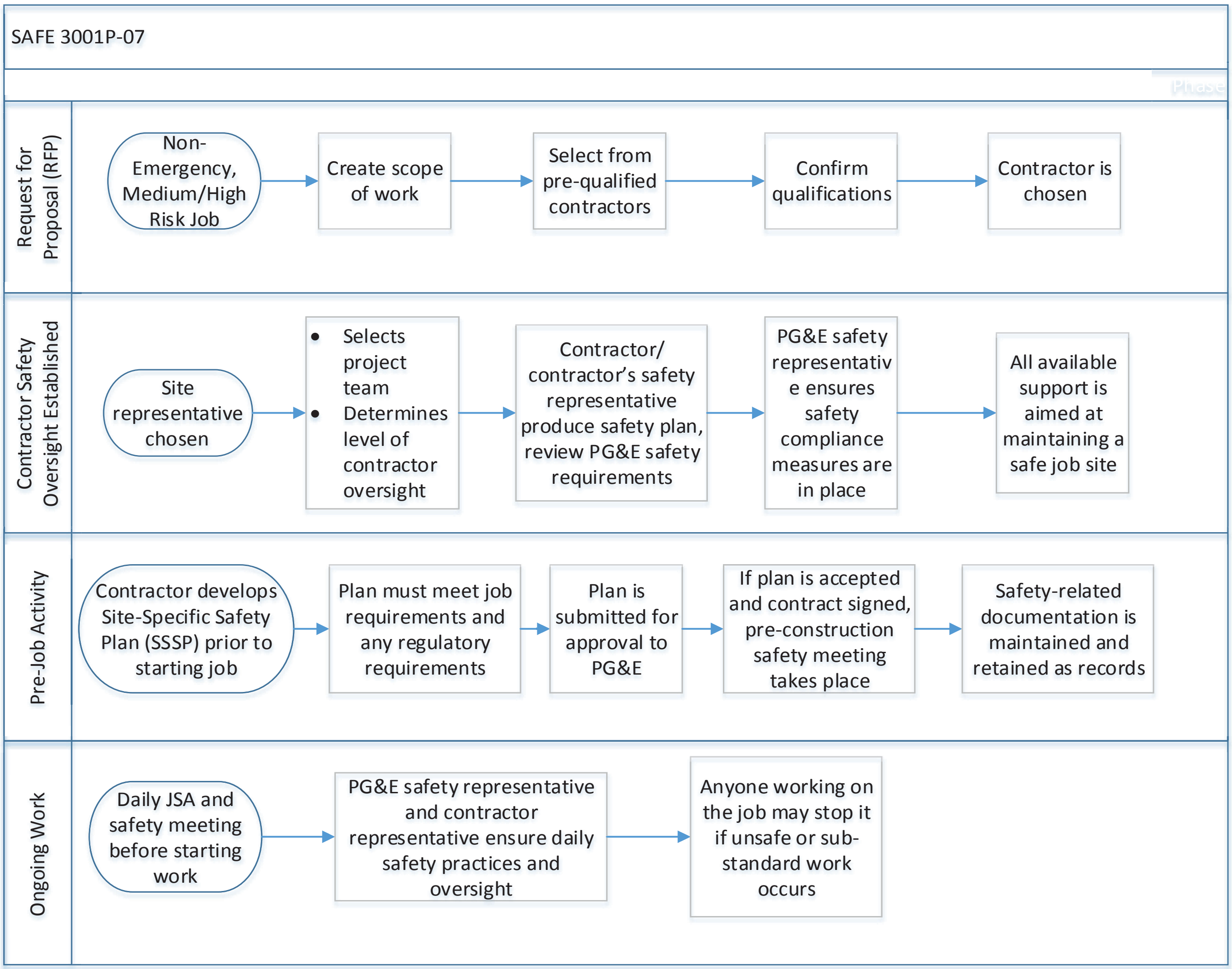
Where?	What Changed?

Contractor Safety Oversight Procedure – Gas Operations

Table 2	Added to the list of responsibilities of the Competent Site Representative
Section 2.4, number 3	Added to the list of project team responsibilities
Section 4.2	Updated contractor safety observations criteria
Attachments	Added attachment 6 for contractor safety evaluations in ISN
Section 4.1	Added requirements for PG&E Safety Representative
Section 7	Added section to include ISN Monitoring and Schedule Sharing

Contractor Safety Oversight Program - Gas Operations

APPENDIX A, PROCESS MAP



PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 11

CHANGE LOG FOR 2020 GAS SAFETY PLAN

Attachment 11
Change Log for 2020 Gas Safety Plan

This attachment lists changes in both the report narrative and the attachments between PG&E's 2019 Gas Safety Plan and 2020 Gas Safety Plan.

Section	Change Log	Change Description
I.3.b	Workforce Safety	Added graphic showing Reduction in Injury Severity/Cost per Claim
I.4	Rewarding Safety Excellence	Added 2019 Caught Being Safe Program Metrics
I.5	Natural Gas Leak Abatement	Added description of Natural Gas Leak Abatement mandate on developing and providing the biennial Leak Abatement Compliance Plan as an attachment to the Gas Safety Plan.
II	Safety Culture	Added description of 100-Day Gas Safety Plan and 2019 milestones resulting from partnerships with leadership, Grassroots teams and the Union.
II.1	Employee Engagement	Enhanced discussion and added Safety Leadership Development and Leader in the Field.
II.1.a	Corrective Action Program	Adding detailed description of the Corrective Action Program lifecycle and the number of cause evaluations completed in 2019.
II.2	PG&E Corporate and Gas Safety Committees	Added Subsection a) Gas Operations Safety Council and b) Gas Operations Grassroots Safety Teams and additional description of each team.
III	Process Safety	Expanded Management of Change (MOC) discussion to include MOC process graphic and listing procedures developed as part of MOC effectiveness review and gap analysis. In addition, expanded Learn from Experience discussion to highlight key milestone of being in compliance with AP 754, Process Safety Performance Indicators (PSI) and included graphic of Pyramid Framework for PSI.
IV.2.a	Gas Storage	Added discussion of the Natural Gas Storage Strategy.
IV.2.h	Data	Added Table summarizing the Data Asset Family Strategic Objectives and Progress to Date
IV.3	Risk Management Process	Added language about the Enterprise Risk Committee of VPs from each LOB and its monthly meetings to discuss risk management program strategies and challenges for top risks. Updated 2019 Gas Operations Enterprise Risks and Enterprise Risk Management: Cross-cutting Factors.

Attachment 11
Change Log for 2020 Gas Safety Plan

This attachment lists changes in both the report narrative and the attachments between PG&E's 2019 Gas Safety Plan and 2020 Gas Safety Plan.

Section	Change Log	Change Description
IV.5.m	Community Pipeline Safety Initiative	Added description of ongoing operation and maintenance activities once the Community Pipeline Safety Initiative has been completed.
IV.6.c	Supplier Quality Assurance (SQA) for Distribution and Transmission	Removed graphic.
V.2	Workforce Safety Projects	Removed table and provided discussion on other ongoing initiatives along with their progress.
VII.2	Lean Capability Center	Adding discussion on total number of huddles established in Gas Operations and Lean Sustainability Reviews.
VII.3	Process Management	Condensed section but enhanced discussion on the 25-step approach to Process Management and added figure that outlines the 25-steps.
Attachment 1	2020 Leak Abatement Compliance Plan	New attachment.
Attachment 2	Change Logs for Asset Management Plans, Emergency Response Plans, Gas Control Center Standard	Updated attachments.
Attachment 3	Document Number: GP-1109, Data Asset Management Plan, Rev. 1	New attachment.
Attachment 4	Utility Standard: GOV-6101S, Enterprise Corrective Action Program Standard, Rev. 10	New attachment.
Attachment 5	Utility Procedure: GOV-6101P-08, Corrective Action Program Procedure, Rev. 0	New attachment.
Attachment 6	Utility Procedure: TD-4014P-04, Change Control Process for Gas Organizational Changes, Rev. 0b	New attachment.
Attachment 7	Utility Procedure: TD-4014P-05, Field Design Change Process for Distribution Lines and Dual-Asset Facilities, Rev. 1	New attachment.
Attachment 8	Utility Procedure: TD-4014P-06, Field Design Change Process for Transmission Pipelines and Transmission Station Designs, Rev. 1	New attachment.
Attachment 9	Gas Design Standard: A-38, Purging Gas Facilities, Rev. 1c	New attachment.
Attachment 10	Contractor Safety Oversight Procedure – Gas Operations; Utility Procedure: SAFE-3001P-07 Rev. 3	Updated attachment.
Attachment 11	Change Log for 2020 Gas Safety Plan	New attachment.
Attachment 12	Table of Concordance	New attachment.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 12

TABLE OF CONCORDANCE

2020 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.	V. 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 2020 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 2020 Gas Safety Plan provides a view into the safety activities PG&E pursues every day and highlights the specific safety work performed in 2019.
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.

PUC Section	Section Location(s) in Gas Safety Plan
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. b. Workforce Safety I. 4. Rewarding Safety Excellence II. Safety Culture III. Process Safety IV. 2. d. Measurement and Control (M&C) IV. 3. Risk Management Process IV. 5. a. iv. Pipeline Patrol and Monitoring IV. 5. b. Pipeline Markers IV. 5. f. Vintage Pipe Replacement IV. 5. h. Corrosion Control IV. 5. j. Leak Survey IV. 5. l. Overpressure Elimination Initiative IV. 6. b. Operations Clearance Procedure

PUC Section	Section Location(s) in Gas Safety Plan
	IV. 7. Mitigating the Risk of Inadequate Response and Recovery IV. 7. b. Cyber Security IV. 7. c. Valve Automation V. 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.	IV. 4. Records and Information Management IV. 5. e. Strength Testing VI. Compliance Framework VII. 4. Quality Management
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.	IV. 2. a. Gas Storage IV. 2. c. Transmission Pipe IV. 2. d. Measurement and Control (M&C) IV. 2. e. Distribution Mains and Services IV. 2. f. Customer Connected Equipment IV. 2. g. Liquefied Natural Gas and Compressed Natural Gas IV. 5. c. Distribution Pipeline Replacement IV. 5. f. Vintage Pipe Replacement IV. 5. h. Corrosion Control IV. 5. m. Community Pipeline Safety Initiative IV. 6. a. System Pressure and Capacity IV. 7. a. Gas Systems Operations and Control VII. 4. Quality Management

PUC Section	Section Location(s) in Gas Safety Plan
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.	IV. 5. a. Damage Prevention IV. 5. a. i. Public Awareness IV. 5. a. iii. Locate and Mark Program IV. 5. a. iv. Pipeline Patrol and Monitoring IV. 5. d. Cross-Bore Mitigation IV. 5. g. In-Line Inspection IV. 5. j. – Leak Survey IV. 5. k. – Leak Repair VI. 4. Supportive Controls
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.	II. 1. c. Material Problem Reporting III. Process Safety IV. 2. e. Customer Connected Equipment IV. 2. g. Liquefied Natural Gas and Compressed Natural Gas IV. 5. l. Overpressure Elimination Initiative IV. 7. Mitigating the Risk of Inadequate Response and Recovery IV. 7. a. Gas System Operations and Control IV. 7. b. Cyber Security IV. 7. c. Valve Automation V. 3. Workforce Training V. 4. Gas Operator Qualifications V. 5. Contractor Safety and Oversight

PUC Section	**Section Location(s) in Gas Safety Plan**
	VII. 7. Benchmarking and Best Practices
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. 3. a. Public Safety IV. 5. k. Leak Repair IV. 7. a. Gas Systems Operations and Control IV. 7. c. Valve Automation IV. 7 d. Emergency Preparedness and Response
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.	IV. 5. e. Strength Testing IV. 5. l. Overpressure Elimination Initiative
961 (d) (8): Prepare for, or minimize damage from, and respond to, earthquakes and other major events.	IV. 5. i. Earthquake Fault Crossings IV. 7. d. 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.	IV. 1. Asset Management System
961 (d) (10): Ensure an adequately sized, qualified, and properly trained gas corporation workforce to carry out the plan.	V. Workforce
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	II. Safety Culture V.6. Partnership with Labor Unions

PUC Section	Section Location(s) in Gas Safety Plan
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.	
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 2019. 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.