

APPENDIX A

PACIFIC GAS AND ELECTRIC
GAS SAFETY PLAN

June 28, 2013
Revision 1
GP-1000

**PACIFIC GAS AND ELECTRIC
GAS SAFETY PLAN**
*GP-1000
Revision 1*

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PACIFIC GAS AND ELECTRIC GAS SAFETY PLAN

*Revision 2
June 28, 2013*

*PG&E's Safety Principle - Nothing is more important than
public and employee safety.*

I. INTRODUCTION

PG&E is working every day towards our vision to become the safest, most reliable natural gas system in the nation. We owe it to our communities—the communities that our customers and employees call home—to fulfill that commitment.

We can achieve this vision through gas safety excellence. Gas safety excellence puts safety at the heart of everything we do. This means operating our gas system safely and efficiently while encouraging employees to speak up and take action for safety. Across our vast service area, our employees are working together to drive change throughout the system.

While we still have much work to do, we are making significant progress and the change that is under way is real and measurable. PG&E's Gas Safety Plan details this progress and also highlights how PG&E plans to continue its journey to achieving Gas Safety Excellence.

Achieving excellence means rethinking every aspect of running our gas operations—from the daily maintenance of our system to the long-term management of our physical assets. The intent of PG&E's Gas Safety Plan is to provide an overarching safety strategy and framework that ensures alignment and continued improvement relative to best practices.

PG&E's Plan highlights current and committed work, and connects the dots between all of PG&E's efforts to ensure the safety of the gas system, the public, and employees. PG&E's Plan focuses on the company's culture, the policies and procedures that guide day-to-day operations, risk management, employee and contractor training, commitment to compliance, asset management and maintenance, emergency response procedures and plans, and use of records. The Plan also incorporates PG&E's extensive Pipeline Safety Enhancement Plan (PSEP) work.

PG&E's Plan has been influenced by a thorough review of external assessments, including reports by the Independent Review Panel (IRP), and the National Transportation Safety Board (NTSB). It also includes input from regulators and industry associations, including the Pipeline and Hazardous Materials Safety Administration (PHMSA), California Public Utilities Commission (CPUC) senior staff, former NTSB leadership, American Gas Association (AGA), Interstate Natural Gas Association of America (INGAA) and others.

PG&E remains steadfast in its commitment to creating a culture of safety. The unprecedented work we've already accomplished – and the work we are committed to completing – are all steps on our journey to becoming the safest, most reliable gas utility in the nation.

II. REGULATORY SUMMARY

PG&E's Gas Safety Plan is in response to the CPUC's resolution to implement Public Utilities Code (PUC) §§ 961 and 963 to address Senate Bill (SB) 705 which was signed into law on October 7, 2011. PUC § 961 requires that each gas corporation in California develop a plan for the safe and reliable operation of its gas pipeline facilities. PUC § 963 establishes that 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. As stated in SB 705, the overall safety plans of California's natural gas system operators flow from numerous Commission processes in addition to the PHMSA regulations and the gas safety plans should provide a comprehensive articulation of these components, e.g., policies, procedures, standards, and guidelines.

Pursuant to Sections 961 and 963, in D.12-04-010, issued on April 20, 2012, the Commission ordered each California natural gas corporation to develop and implement a plan for the safe and reliable operation of its gas pipeline facilities by no later than June 27, 2012.¹

In D.12-12-009, issued on December 26, 2012, the Commission accepted all gas system operators' safety plans for filing but identified deficiencies in each plan. The Commission ordered that: "Each gas system operator shall, under the direction of the Consumer Protection and Safety Division, resolve all deficiencies identified in the report approved in Ordering Paragraph 2, and each operator shall file and serve a compliance statement updating the safety plan showing how the deficiency was resolved no later than June 30, 2013." In this revised Plan, PG&E has addressed the deficiencies in its original Plan identified by Safety Enforcement Division (SED), formerly Consumer Protection and Safety Division, in its original Plan and has updated the Plan to include an overview of its many safety-related initiatives over the past year.

The Commission has organized the elements of a gas safety plan into five overall categories: (1) safety systems, (2) emergency response, (3) state and federal regulations, (4) continuing operations, and (5) emerging issues. PG&E's Plan follows the organizational structure outlined by the Commission. **Attachment 1** is a table showing how PG&E is addressing each element of PUC §§ 961 and 963 for its gas transmission and distribution facilities within this plan.

III. GAS SAFETY PLAN IMPLEMENTATION AND MAINTENANCE

Public Utilities Code Section 961 requires natural gas system operators to:

- a. Implement its approved plan,² and*
- b. Periodically review and update the plan.³*

This Plan is applicable to all PG&E employees and contractors. PG&E has taken the following steps to ensure the Plan is implemented and continuously maintained:

¹ Pursuant to the Ruling of the Assigned Commissioner Setting Schedule for Comments on Safety Plans, Granting Unopposed Motion to Move Exhibit Into Record, and Adopting Procedures for Commission Consideration of Request to Lift Operating Pressure Limitations on Line 131-30 (Ruling), issued on July 20, 2012, PG&E filed a First Amendment to its Gas Safety Plan on August 24, 2012 to address the concerns expressed by California Assembly Member Jerry Hill regarding coordination and supervision of in-line inspection contractors.

² PUC § 961(b)(3)

³ PUC § 961(b)(4)

- All new employees and contractors will be provided with a copy of the Plan upon employment
- Provided current employees with access to the plan
- The Plan will be reviewed and revised as required once per year, not to exceed 15 months
- Modified versions of the plan will be filed with the CPUC as appropriate unless otherwise directed by the CPUC.

A. Gas Safety Executive Committee

The Gas Safety Executive Committee is responsible for allocating the necessary resources to support the development, implementation and maintenance of the Plan and its components. The Executive Committee is also responsible for approval of the Plan. The Executive Committee includes the following members:

- Executive Vice President, Gas Operations
- Sr. Vice President, Gas Transmission Operations
- Vice President, Public Safety and Asset Integrity
- Vice President, Gas Transmission Maintenance
- Vice President, Gas Distribution Maintenance
- Vice President, Investment Planning
- Vice President, Standards and Policy
- Sr. Director, Gas Systems Operations
- Sr. Director, Asset Knowledge Management
- Director, Regulatory Compliance and Support
- Sr. Director, Safety

B. Gas Safety Team

The Gas Safety Team is responsible for ensuring that the Plan reflects all components accurately and in a timely manner. This includes managing processes to ensure updates to any component of the Plan. The team meets at least annually to review the current Plan and identify updates to the Plan. The team will be responsible for ensuring the Plan is updated at least once annually as required by the CPUC. This team is also responsible for ensuring appropriate communications to employees about the Plan and ensuring the Plan is available to all employees. Gas Safety Team members include a representative from the following organizations:

- | | |
|-------------------------------------|--------------------------------|
| • Distribution Integrity Management | • Investment Planning |
| • Transmission Integrity Management | • Policies and Procedures |
| • Mapping | • Maintenance and Construction |
| • Estimating/Design | • PSEP |
| • Gas Control | • Risk Management |
| • Field Service | • Technical Teams |
| • Training | • IBEW |
| • Quality and Improvement | • ESC |
| • Regulatory Compliance | • Safety |
| • Emergency Response | |

IV. SAFETY FIRST CULTURE

PG&E recognizes that building and maintaining a safety-first culture takes time and continued commitment. As stated in PG&E's Vision and Values (**Figure 1**) PG&E is committed to creating and sustaining a strong culture of safety. Employees are empowered to report and act on safety concerns, further fostering an environment of accountability and ownership where significant and essential behavioral changes can occur at all levels. These efforts include reinforcing clearly defined goals and expectations, structuring incentives to align with those goals, measuring progress using industry benchmarks, and effectively communicating with customers, regulators, and the communities we serve.

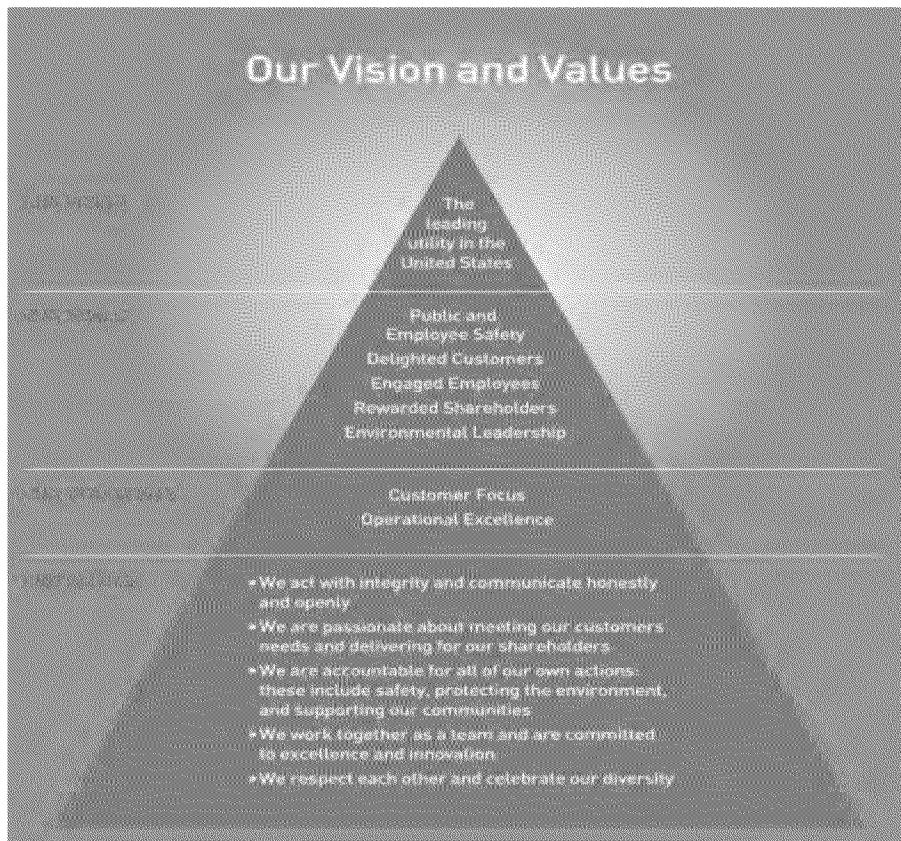


Figure 1

A. Corporate, Company and Line of Business Safety Programs

Figure 2 shows the interrelationship between PG&E's Corporate and Line of Business safety programs.



Figure 2

PG&E’s Board of Directors established the Nuclear, Operations, and Safety Committee which is chaired by a member of the Board of Directors and has a primary focus on public and employee safety. The Committee’s charter (**Attachment 2**) lays out the Committee’s focus on public and employee safety, compliance, and risk management policies and practices (including integrity management for Gas Operations). Senior leaders, in particular those in Gas Operations, regularly engage the Board of Directors in discussions regarding safety.

The Chairman’s Safety Review Committee (**Attachment 3**), under the leadership of PG&E’s Chief Executive Officer, is responsible for reinforcing the role of safety in all aspects of operations and relationships with customers, the public, employees, and suppliers. The Committee also reviews the company’s overall safety strategy and its implementation.

The Executive Safety Steering Committee (ESSC) (**Attachment 4**) reports directly to the President of Pacific Gas and Electric company and is chaired by the Senior Vice President, Safety and Shared Services. The ESSC is responsible for guiding the formulation of PG&E’s public and employee safety and health-related philosophy, policy, strategy and practices, and oversees the implementation of associated actions that lead to a safety first climate and the elimination of safety incidents. Examples of the ESSC’s actions include leadership of a grassroots safety program for employees and introduction of Process Safety Management principles.

The Gas Operations Risk and Compliance Committee (**Attachment 5**) is chaired by the Executive Vice President, Gas Operations. This committee reviews all operations and processes within Gas Operations and the associated risks, including risks related to public safety. The committee also tracks progress and mitigation activities.

PG&E recognizes that building a safety-first organization requires clearly articulated roles and responsibilities, highly-engaged employees, a skilled workforce, sufficient resources to successfully execute on investment plans, standards and procedures written in readily understood English, a rigorous quality assurance/quality control program, and a clear understanding of regulatory and industry requirements. The company is focused on implementing safety enhancement measures to provide safe and reliable service to our customers and a safe work environment for our employees.

B. Gas Safety Excellence

Gas Operations’ vision is to be “The safest, most reliable gas company in the United States” and is focused on reaching this vision through pursuing a strategy of ‘Gas Safety Excellence’.

This strategy is about:

- Putting **safety** and people at the heart of everything
- Investing in the **reliability** and integrity of our gas system
- Continuously improving the effectiveness and **affordability** of our processes

The Gas Safety Excellence strategy has three key elements as shown in **Figure 3**:

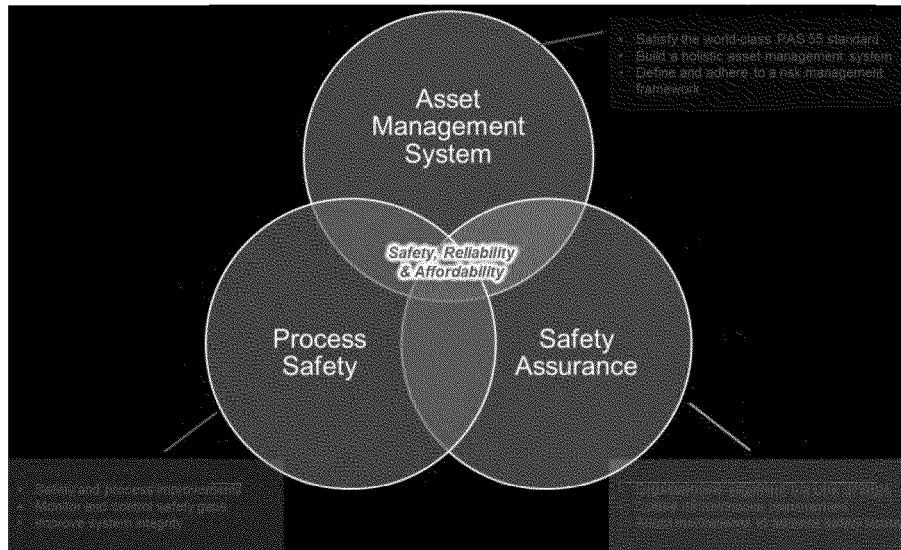


Figure 3

The first element is a comprehensive **asset management system** that provides a holistic approach to monitoring and maintaining the health of our system and assets. With better information provided by such a system, PG&E can promptly identify safety concerns, manage operational risks and make informed decisions to improve operations. We have chosen to adopt PAS55 as our asset management system. Operators of the standard are able to display the following characteristics:

- Risk based approach to managing assets
- Data-driven approach to formulating strategies and plans
- Investments focused on risk mitigating efforts

The second element is a robust plan to strengthen **process safety**. Throughout every function of the organization, PG&E is making safety and process improvements. With a focus on system integrity, PG&E continues to increase our understanding of the condition of our assets. PG&E is testing and upgrading the methods used to monitor and control our assets, while designing new programs devoted to integrity management and hazard identification.

The third element is a company culture committed to **safety assurance**. Safety assurance represents the alignment of human performance with the organizational strategy. Aligned goals help us achieve this alignment by providing employees with a clear understanding of how their work supports the goals of their department and, ultimately, the vision. PG&E has the ability to inspire a culture focused on safety and continuous improvement. To do this, PG&E must fully

understand the organizational culture through regular assessments and a holistic approach to employee engagement.

To demonstrate our achievement of Gas Safety Excellence, PG&E is working to attain a globally-recognized certification in 2014 - Publically Available Specification 55 (PAS 55). In fact, PG&E will be one of the first utilities in the United States to receive this type of certification, which is awarded by an independent, third-party auditor.

PAS 55 offers many benefits to PG&E Gas Operations. This certification will demonstrate that PG&E's operations have reached a high level of maturity, from which PG&E can build upon and improve. Other benefits include standardized procedures that integrate safety into all processes and a risk management standard for PG&E assets that allows the development of mitigation strategies for all stages of an assets lifecycle. PAS 55 also requires that initiatives be risk-based, which will focus resources toward the right threats at the right time. PG&E believes that PAS 55 certification will increase the confidence of PG&E customers and regulators in our ability to operate safely.

Receiving PAS 55 certification will be the first major milestone of achieving Gas Safety Excellence, but our work will not stop there. PG&E will need to maintain certification on an on-going basis, and PG&E's work on process safety performance and aligning organizational culture to PG&E's goals will be an on-going process (**Figure 4**).

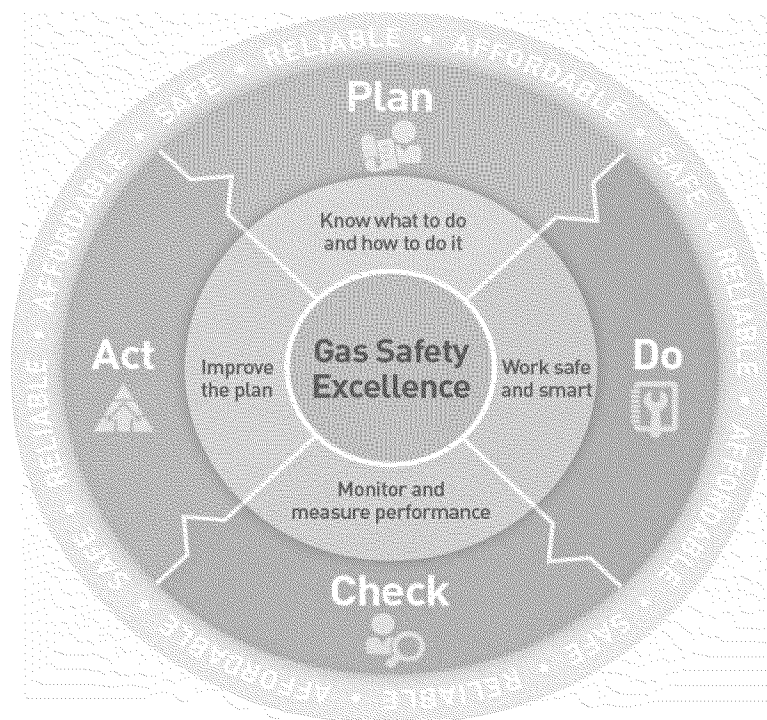


Figure 4

An important component of being able to make and sustain the changes in the organization is the ability to connect our strategies to the rest of the organization. By introducing and embedding Line of Sight goals (**Figure 5**), the connections are made clearer. Line of Sight goals

development is an annual process that highlights the key strategic actions that if delivered, will advance the strategy and performance of the business. These actions, are linked upwards to the overall strategy of the organization - being safe, reliable and affordable, and then through a cascade process, linkage to departments, team and individuals. Line of Sight goals will remain an important vehicle in delivering GSE over the coming years.



Figure 5

C. Gas Organization

PG&E's Gas Operations organization is structured around eight distinct functions and identified key processes. The eight functions with corresponding descriptions include:

- Asset Knowledge Management - Defining the assets and the associated attributes of each (data and records management) to provide and sustain real-time and accurate (traceable, verifiable and complete) gas transmission and distribution asset information
- Standards and Policies - Defining the safety requirements and standards that PG&E follows (meeting or exceeding compliance requirements)
- Public Safety and Asset Integrity - Reviewing the assets to assess their physical condition, identifying degradation threats, defining actions necessary for continued safe operation (integrity management), and emergency response planning and training
- Project Engineering and Design - Engineering and designing assets to address safety and improvements

- Investment Planning - Establishing resource plans and relative priorities
- Transmission - Executing transmission work in the field effectively and efficiently (performing construction, maintenance activities)
- Distribution - Executing distribution work in the field effectively and efficiently (performing construction, maintenance activities)
- Gas Systems Operations - Operating the facilities in a safe and reliable manner (monitoring safe system performance and operations and emergency response)

The primary processes identified for Gas Operations (**Attachment 6**) each have an accountable process owner who functions as the accountable person. The process owners are responsible for resolving issues, providing follow-up and identifying and implementing improvements.

D. Employee Engagement

Engaging the workforce means demonstrating to all employees that the company values and acts on their ideas, input and personal development, including the availability of training.

PG&E has created a strong line of sight between organizational objectives and the work performed on the gas asset system by employees. Aligning corporate strategies and work plans supports a much more fluid bottom-up flow of ideas and feedback to enable continuous improvement in the business.

Gas Operations' executive leadership team visits offices and field locations to speak directly with employees and hear firsthand their thoughts on what PG&E is doing well and where improvements are needed. However, talking to and listening to employees alone is not enough to demonstrate to employees that PG&E's leadership wants their input and ideas of how to improve. To show the focus on engagement, PG&E leadership has created specific engagement activities around key aspects of work heavily leveraging employee feedback. The selection of new gas crew trucks that are replacing the aging fleet were almost entirely led by field employees. PG&E is in the process of building a new gas training facility with extensive employee engagement around design, layout, training areas, and equipment. Additionally, course content and technology are being led by cross functional employee teams. The company is also working hard to close the feedback loop by developing easy-to-use and centralized mechanisms to obtain employee feedback (further described under the Corrective Action Program in Section X.A. Gas Operations is using this information to develop processes to ensure meaningful employee input is incorporated into operations decisions.

PG&E also has established gas technical teams and a Grassroots Safety Team which provide additional channels for obtaining input and recommendations on Gas Operations' processes.

1. Grassroots Safety Team

The grassroots safety philosophy hinges on management and union-represented employees sharing responsibility for safe practices and implementation of corrective actions. Leadership is the key to safety performance, and safety leadership comes from all levels of an organization. This team is an employee-led effort that promotes safe work habits, shares information and best practices, promotes open and honest communications, and finds innovative methods to perform work safely. Grassroots members, at all levels, have direct influence on the development and implementation of initiatives developed by the ESSC.

The companywide Grassroots Safety Team structure allows for the sharing of grassroots based ideas across all lines of business (LOB) in order to identify best practices and improve safety performance. Each LOB is committed to supporting and maintaining a functioning Grassroots Team to gather ideas and feedback from employees on safety issues. Grassroots team members discuss issues and solutions with all LOB representatives as well as senior leadership (Senior Director of Safety) for PG&E. A member of the Grassroots team serves as a liaison to the ESSC and ensures alignment across LOB Grassroots teams.

2. Gas Technical Teams

To ensure that the standards, procedures, tools, and technologies are current, PG&E maintains gas technical teams as shown in **Attachment 7**. These teams support the development, review, and updating of PG&E's gas documents. Technical team members are subject matter experts and/or stakeholders in specific areas within Gas Operations which ensures that issues and opportunities are identified and responded to quickly and effectively.

The gas technical teams provide support, recommendations, evaluations, and user feedback on the performance, operation, maintenance, development, and implementation of the following internal resources, documents, and activities:

- Materials
- Equipment
- Standards
- Construction work methods
- Maintenance and Operations (M&O) procedures
- Conduct timely reviews to ensure that company standards, tools, and procedures remain current
- Address significant changes in new tools, technologies, policies, and procedures

V. SAFETY SYSTEMS

Public Utilities Code Section 961 requires natural gas system operators to:

- (1) Identify and minimize hazards and systemic risks,⁴ and*
- (2) Identify the safety-related systems that will be deployed to minimize hazards.⁵*



Nothing is more important than public, employee and contractor safety at PG&E. PG&E has numerous programs, policies and procedures in place to identify and minimize hazards, risks, and dangerous conditions.

⁴ PUC § 961(d)(1)

⁵ PUC § 961(d)(2)

A. Risk Management

1. Enterprise Risk Management Framework

PG&E's Enterprise and Operation Risk Management (EORM) organization has developed a corporate standard (RISK-5001S) that describes the requirements for conducting effective operational risk management.

Potential key risks are identified by the line of businesses and prioritized by the senior officers to develop the enterprise-level risks as shown in **Table 1**. These enterprise-level risks are prioritized for review by the appropriate Board of Director Committee on an annual basis.

Enterprise-Level Risk	Enterprise-Level Risk Description
Gas System Safety	A system condition associated with gas facilities that could directly lead to personal injury or fatality of either the public and/or employees.
Electric System Safety	A system condition associated with electric facilities that could directly lead to personal injury or fatality of either the public and/or employees.
Nuclear Operations and Safety	A core damaging event may result in radiological release, or extended shutdown of the plant (> 3 months, >\$100M).
Hydro System Safety	The failure of a PG&E dam or other hydro facility that may result in significant damage to PG&E facilities?, third parties, and the environment.
Wildfire	PG&E assets may initiate a wild land fire that is not easily contained and that endangers the public, private property, sensitive lands, and/or leads to long-duration service outages.
Emergency Preparedness and Response to Catastrophic Events	The risk of ineffective preparation for or response to a catastrophic emergency. This risk includes business continuity and disaster recovery.
Cyber-security	An intentional/unintentional loss of control of information and systems used for gas and electric operations (e.g., SCADA, plant networks, trading, etc.) and business operations .
Regulatory Uncertainty	Unfavorable regulatory environment could result in the company being unable to provide safe, reliable and affordable service to its customers or finance its operations.
Customer Affordability	A lack of affordable service could lead to extreme adverse customer reaction.
Distributed Generation	Potential for increased levels of customer-side distributed generation adoption may result in shifting significant costs to non-adopting customers and operational issues in the distribution system.
Environmental	The risk of actual or perceived impacts to human health or the environment from past, present, or future operations.

Table 1

Gas Operations has established a Risk and Compliance Committee, chaired by the Gas Operations executive vice president. Under the guidance of the Risk and Compliance Committee, Gas Operations' risk management team with the help of industry experts has developed a granular risk scoring system, guidelines and corporate objectives to quantify likelihood and consequence of failures, resulting in risk scores for all identified operational risks. Additionally, this process is integrated with investment planning and aligned with the Enterprise Risk Management framework

Gas Operations is using the risk management framework and roadmap built by the EORM team to achieve best-in-class operational risk management. As part of the risk management framework, the inherent risk, current residual risk and the forecasted residual risk (for proposed mitigations) are calculated. The enterprise-level risk with the most significant impact on operations is Gas System Safety. Through a structured process, Gas Operations has identified the three principal, overarching risks for Gas Operations: (1) loss of containment; (2) loss of supply and service; and (3) inadequate response and recovery.

- 1) **Loss of containment:** risk that gas will escape the system. PG&E's plan to mitigate this risk is driven by its operational risk assessment and integrity management programs including Distribution Integrity Management, Transmission Integrity Management, and Damage Prevention, among others. These programs focus on identifying ways to mitigate the risks associated with identified "threats," including corrosion, natural forces, excavation damage, other outside force damage, material, weld or joint failure, equipment failure and incorrect operation.
- 2) **Loss of supply and service:** risk that PG&E will be unable to deliver natural gas to one or more customers. PG&E's plan to mitigate this risk is largely driven by Systems Operations and by the new Gas Control Center. Systems Operations is focusing on three risk mitigation drivers: (1) process; (2) visibility; and (3) control. PG&E will be instituting new processes and installing thousands of monitoring and control points to mitigate risks and improve safety. In addition to Systems Operations, PG&E's efforts to mitigate this risk include investing in capacity, including new business, investing in training so that people execute work properly and investing in technology.
- 3) **Inadequate response and recover:** risk that, if there is a loss of supply or service or a potentially hazardous leak, PG&E will not adequately respond to make the situation safe. Mitigating this risk involves proper training, a robust emergency response plan and coordination both internally as well as with outside agencies.

These risks are managed by eight asset families within Gas Operations as shown in **Figure 6**. Each asset family has an 'Asset Family Owner (AFO) who is responsible for working with subject matter experts to identify and manage risks within their asset family and develop risk-based asset management plans.

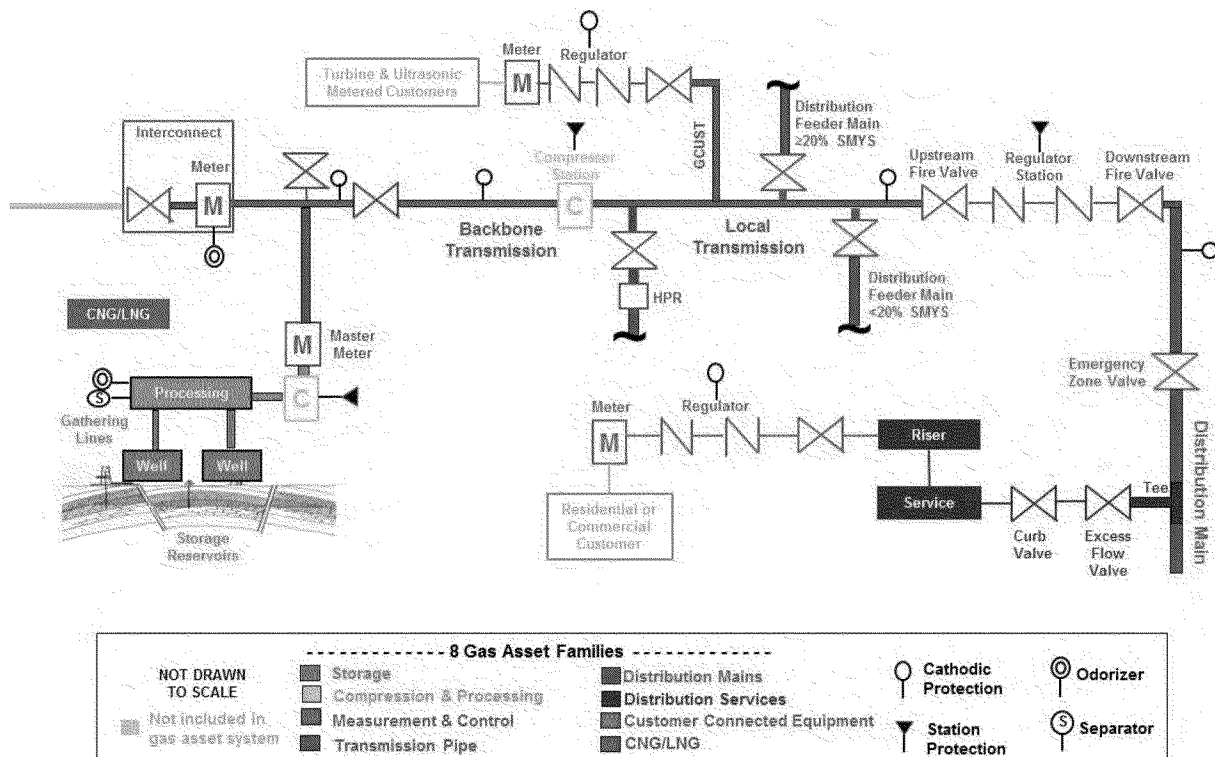


Figure 6

3. Risk Register

All identified risks for Gas Operations are recorded in a “risk register” which provides a record of what PG&E is doing to manage each risk in the field. The risk register is a mechanism for consistently capturing and scoring risks across Gas Operations.

Using a standardized methodology, the likelihood of failure and consequence of failure are determined, and used to calculate the risk score. To ensure accuracy and consistency, the risks scoring and mitigating actions are reviewed by AFOs and subject matter experts with support from the risk management team and calibrated across the asset families.

A calibrated risk register is rolled up and compiled to identify the most significant operational risks for Gas Operations. Prioritization is based on the highest risk score. The prioritized risks are used in strategy development and investment planning.

On an ongoing basis, perceived risks are highlighted by subject matter experts and engineering specialists. Severe risks are acted upon immediately while other risks are added, scored and maintained on the asset family risk register with mitigating projects and programs considered and prioritized both within and across asset families.

The Gas Operations risk register currently identifies 85 primary operational risks. The top 20 Gas Operations risks (based on the risk register scoring) are shown in **Table 2**.

Risk #	Risk - In order of highest score
1	Transmission: Stable – Construction
2	Transmission: Stable – Manufacturing
3	Distribution: Time Dependent – Internal Corrosion
4	Distribution: Time Independent – Excavation Damage, Third Party – Rupture leading to potential impact on safety
5	Distribution: Time Independent – Excavation Damage, Cross Bore
6	Distribution: Stable – Manufacturing
7	LNG/CNG: Time Independent – Equipment Failure, CNG Fueling Station
8	Customer Connected Equipment: All – Inside meter sets
9	Transmission: Time Dependent – External Corrosion
10	Distribution: Time Independent – Third Party Excavation Damage – No rupture
11	Distribution: Time Independent – Incorrect Operations
12	Measurement & Control: Time Independent – Large High Pressure Excursion
13	Storage: Time Dependent – Internal Corrosion Erosion
14	Transmission: Time Independent – Mechanical Damage
15	Storage: Stable – Construction
16	Storage: Time Independent – Weather & Outside Forces – Flooding
17	Customer Connected Equipment: Stable – Manufacturing, meter sets
18	LNG/CNG: Time Independent – Third Party Damage
19	Customer Connected Equipment: Stable – Manufacturing, regulators
20	Compression & Processing: Time Independent – Incorrect Operations

Table 2

C. Process Safety

Process Safety is a comprehensive, risk-based approach based on fully identifying, understanding and mitigating risk. The goal of process safety is to develop effective processes and ensure employees fully understand the implications of what they are doing. Process Safety provides value to external and internal stakeholders including the public and customers, regulators, and employees in a variety of other industries.

Process Safety requires understanding hazards and risks, planning and implementing layers of mitigating strategies that help manage risk, and learning from experience. The fundamental benefit of Process Safety is a safer business.

Key activities that PG&E will evaluate for risks include facility design and modification, operational procedures, workforce competence, human factors, emergency arrangements, protective devices, instrumentation and alarms, inspection and maintenance, permit to work, asset records and data quality, and third party activities.

An example of applying Process Safety is the Pre Start-up Safety Review (PSSR) implemented by PG&E. A PSSR helps ensure that risks have been identified and addressed; that there is agreement on all start-up requirements including training, drawings, spare parts and operating procedures before starting new equipment; and that there are alternatives to address problems.

D. Standards, Policies and Procedures

PG&E's gas standards, including O&M procedures, are developed to comply with federal and state pipeline safety regulations. The Gas Operations Compliance department monitors and tracks changes to legislation and regulatory requirements and ensures implementation. The Codes and Standards department is responsible for documenting them so that policies, standards, practices, and training materials are updated, as appropriate.

PG&E has numerous standards, policies and procedures in place to support Gas Operations and to ensure work performed by employees and contractors is done safely and consistently. A list of PG&E's active and proposed gas guidance documents as of June 24, 2013 is included in **Attachment 8**.

The company's gas guidance document development and update process follows the requirements and steps described in the corporation's GOV-2001 series and Gas Operation's TD-4001 series of standards and procedures. Each existing published document has assigned subject matter experts that perform assessments of guidance documents to determine the need for developing or altering the document. PG&E's gas guidance documents are defined as follows:

- **Policy** - Provides high-level, broad instruction about a significant business operation, subject or function, consistent with laws and regulations, the company's vision, values, and goals, and any direction from the Boards of Directors.
- **Standard** - Describes the major steps of a work process and/or major internal or external compliance requirements, and the roles and responsibilities of those involved. A standard may involve one or more organizations, departments, job functions, or compliance requirements. A standard can be a stand-alone document or incorporated in a manual with implementing procedures and other related information, e.g., forms, drawings, or specifications.
- **Procedure** - Detailed, step-by-step instruction that describes the functions, tasks, and expectations of employees who are responsible for performing a specific function or task. A procedure includes or refers to all safety, health, and environmental instructions that an employee needs to perform the work correctly. A procedure can be a stand-alone document or incorporated in a manual with governing standards and other related information, e.g., forms, drawings, or specifications.
- **Bulletin** - A brief, interim, and temporary guidance document designed to heighten awareness of a particular issue, usually one or more of the following: an immediate change in how business is done and/or information about a safety,

health or environmental incident or issue and resulting required actions, and/or information about a new mandatory compliance requirement, and/or a clarification of a previous instruction (“how-to” instruction often is included). As soon as practicable, the document owner incorporates the bulletin information into the parent policy, standard, or procedure and cancels the bulletin.

The company also has gas technical teams comprised of cross-functional representatives that assure the standards, procedures, tools, and technologies used in their specific area remains current and updated. Major duties include:

- Identifying issues and resolutions
- Identifying documents
- Writing and/or revising guidance documents
- Approving documents
- Approving products
- Identifying training.

Work quality field assessments are conducted using published work procedure documents to ensure the document is being followed and to identify further areas of opportunity. Findings and identified deficiencies in the documents are provided to the appropriate technical team for evaluation and revisions.

E. Pipeline Safety Enhancement Plan (PSEP)

PG&E’s PSEP is one of the most aggressive and comprehensive gas transmission pipeline modernization programs in the United States which will enhance safety and improve operations by fundamentally changing the way PG&E manages its gas pipeline assets. Ultimately, PG&E will comprehensively assess all of its natural gas transmission pipelines. The PSEP is part of a broader Gas Operations strategy and includes improvements PG&E is making to its existing pipeline replacement and maintenance, risk mitigation and integrity management programs. PSEP compliance reports, including a broad range of program information and progress, are provided to the CPUC on a quarterly basis and are available to the public via PG&E’s website.

PG&E has completed an unprecedented amount of work since the PSEP began in 2011. PG&E has: validated 456 miles of transmission pipeline, including 358 miles validated through hydrostatic pressure testing; installed 76 automatic and remote control valves that will automatically shut off gas in an emergency; validated the safe operating pressure for all 6,750 miles of its gas transmission pipelines; replaced 55 miles of transmission pipeline; and collected and digitized more than 3.7 million pipeline records as we implement an advanced records and information management system with next-generation technology and tools

The main components to PG&E’s PSEP are described below.

1. Pipeline Modernization

PG&E is establishing a known margin of safety on every gas transmission pipeline segment and ensuring pipeline integrity through strength testing, pipeline replacement, and pressure reductions. Work during 2011-2014 addresses pipeline segments located in highly populated areas, with certain manufacturing threats that have not been previously pressure tested. PG&E’s 2015 Gas Transmission and Storage Rate Case will address pipeline segments in less populated areas or retest pipeline that has not been pressure tested to modern standards.

Additionally, as part of pipeline modernization, PG&E is retrofitting specific pipelines to accommodate the use of In-Line Inspection (ILI) tools.

2. Valve Automation

PG&E is installing automated valves in highly populated areas and where pipelines cross active seismic faults to enable PG&E to remotely or automatically shut off the flow of gas in the event of a pipeline rupture. Under the design criteria for the program, actuated valves are spaced so that in the event of a full pipeline rupture, pressure in the pipe will dissipate in minutes following valve closure. The Valve Automation Program will also replace valves where needed to assure “pig-ability” in the pipeline system.

The Valve Automation Program will be implemented in a phased approach. During Phase 1 (2011-2014), PG&E will replace, automate and upgrade approximately 210 isolation valves resulting in approximately 410 miles of gas transmission pipeline in Class 3 and 4 areas being equipped with actuated isolation valves, typically at 5-8 mile intervals, and automatic shut-off valves being installed at active earthquake fault crossings. Phase 2 will include the automation of roughly 300 additional valves.

PG&E will also evaluate new pipeline projects and replacement pipeline projects for valve automation based upon the decision-making criteria in this program.

In addition, PG&E is upgrading its Supervisory Control and Data Acquisition (SCADA) system to allow operators in its Gas Control Center to identify and respond quickly to isolate sections of pipeline if a line rupture occurs. The valve station where RCV and ASV valves are installed will have pressure conditions and valve position transmitted to the SCADA system increasing the visibility of pipeline conditions by PG&E’s Control Room Operators.

3. Pipeline Records Integration

PG&E is transitioning away from reliance on traditional paper records and implementing fully integrated electronic asset management systems. By having both asset and associated future maintenance information in an integrated system, engineers can more effectively evaluate system conditions, identify system component performance trends, enable timely preventative maintenance, reduce corrective maintenance and improve the overall safety and reliability of the system. These efforts will provide a seamless data model and will allow for traceability that can be used to isolate issues in a more efficient and timely manner.

a. Gas Transmission Asset Management Project (Mariner)

PG&E is consolidating pipeline data and records systems, collecting and verifying all pipeline strength tests and pipeline features data necessary to calculate the MAOP for all gas transmission pipelines and associated components. Mariner will substantially enhance and improve:

- The amount and the types of information that PG&E collects and maintains electronically about its transmission pipeline system;
- The business processes for collecting, validating and retaining pipeline systems and maintenance data;
- The traceability of materials used in the construction and maintenance of PG&E’s natural gas pipelines; and
- PG&E’s ability to assess and mitigate potential public safety risks.

The system consists of the following components:

- 1) Collect, digitize, validate, and migrate pipeline data into integrated electronic information management systems, SAP and GIS (Geographic Information System)
- 2) Upgrade the existing GIS system to track component-level information;
- 3) Upgrade the interfaces among information management systems; and
- 4) Develop and implement mobile technology

To date, the Mariner project has made progress in several functional areas by providing new mobile devices to field personnel, replacing outdated hardware, providing access to electronic maps, and converting records as part of the MAOP Validation Project. Mariner is also progressing toward deploying integrated risk management tools, integrating work management and asset systems, and mobilizing corrective and preventative maintenance processes.

F. Transmission Integrity Management Program

All pipeline operators are required by 49 CFR, Part 192, Subpart O – Pipeline Integrity Management, to implement a Pipeline Integrity Management Program to assess and manage the integrity of all gas transmission pipelines in High Consequence Areas (HCAs). HCAs are based on the population density and types of critical facilities (such as schools and hospitals) around the pipeline. The Transmission Integrity Management rule has been implemented through PG&E's Transmission Integrity Management Program (TIMP). The TIMP is a mature, well-defined program for assessing the risk related to different segments of pipe on the system and taking the appropriate action to prevent or mitigate these risks. While the TIMP risk management process contains many elements that overlap with risk assessment processes within the risk register, it is a separate process that considers threats to individual segments of pipe, as opposed to the system as a whole.

The integrity management risk process within the operation and maintenance of transmission pipeline is specified within a set of Risk Management Procedures (RMP-01 through RMP-13) as shown in **Attachment 9**. These procedures outline a set calculation of risk within a relative risk model on each segment of pipe within the transmission system.

The approach for assessing risk is based on an assessment of likelihood and consequence of a leak or rupture, and uses the nine threats listed in the threat matrix (**Attachment 10**) to identify high-risk segments. The risk process gathers reviews and integrates data to calculate risk, prioritizes preventive and mitigative measures, and monitors for operational changes that may require additional actions. The output of the risk model and threat algorithm is a prioritized list of integrity assessment plans.

Threats to the transmission pipeline system are analyzed by risk engineers and additionally reviewed with Integrity Threat Steering Committees. HCA assessment plans are reviewed and modified annually as necessary. The risk analyses for both HCAs and non-HCAs are based on data that includes cathodic protection history, leak survey results, knowledge of encroachments and damages, GIS-based data containing pipeline attributes and the proximity population along the pipeline.

Three methods of integrity assessment are allowed under Subpart O: In Line Inspections (ILI), strength testing and direct assessment. PG&E uses a combination of all three federally approved integrity assessment methods depending on the threats identified on a pipeline segment. In addition to these assessment methods governed by regulation, PG&E continues to reduce risk both in HCAs and non-HCAs using a host of additional monitoring and assessment

methods and technologies, such as leak survey, radiography, cathodic protection monitoring, aerial patrol, fault crossing pipe replacements and monitoring, pipeline surveillance, and geotechnical monitoring.

Approximately 20 percent of PG&E's gas transmission system is located in HCAs and subject to the associated TIMP requirements. The remaining 80 percent of the gas transmission system is located in non-HCAs and part of PG&E's existing integrity risk management processes, which include the risk analysis to determine where certain improvements are necessary to maintain compliance or reduce risk.

G. Distribution Integrity Management Program

PG&E's Distribution Integrity Management Plan (DIMP) governs how we inspect and maintain more than 42,000 miles of pipe, 3.3 million gas service connections and other gas distribution assets. It is a core foundation of PG&E's ongoing efforts to provide safe and reliable service consistent with industry best practices and is based on the federal DIMP regulation as set forth in 49 CFR 192.1007⁶. The DIMP applies to all gas distribution assets and facilities and the program requirements are addressed within RMP-15 (**Attachment 11**). PG&E's DIMP evaluates the risks to PG&E's gas distribution system and proposes mitigations to address those risks. PG&E's DIMP risk algorithm relies on leak history as a proxy for pipeline performance and for determining prioritization of pipeline replacement work. RMP-15 has an annual review process to identify required changes considering previous year's findings. Additionally, a re-evaluation is performed every five years to look at roles and responsibilities, work flows, reporting criteria, definitions, data sources communications plans, contact information and documentation.

A list of data sources currently utilized in PG&E's DIMP risk algorithm is listed in PG&E's RMP-15.

PG&E's Threat Committees⁷ identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to the company's gas distribution pipeline system. Potential and existing threats to the distribution system are evaluated as part of a risk assessment process for the company's distribution facilities utilizing leak information. Areas identified as high risk with negative leak trends are evaluated for root cause and mitigations are recommended.

Once methods for managing and mitigating risks are identified, process specialists (cathodic protection, leak survey, leak repair, valves and meters, pipeline patrol, locate and mark and damages) are responsible for monitoring the impact of the risk management initiatives to determine their effectiveness in minimizing risk to the distribution system. Threat committees are responsible for reevaluating the risk and its root cause to determine a more effective approach.

In addition to the annual review and the five-year re-evaluation, at least one quality assurance audit will be completed each year. At a minimum, a quality assurance audit is

⁶ 49 Code of Federal Regulation (CFR) 192, Subpart P, published on December 4, 2009 at 74 FR 63929.

⁷ In consultation with the Supervising Engineer of Risk Management, members are appointed by the Manager of the Distribution Integrity Management Program. While these committees often include members with gas transmission and gas distribution backgrounds, members have at least two years' experience in the area of expertise of their committee.

performed on the following programs: corrosion control, damage prevention, leak management, regulation maintenance and valve maintenance.

H. Distribution Pipeline Replacement

An important element of providing safe gas distribution service is replacing aging assets. PG&E's historical rate of pipeline replacement is about 30 miles per year. As our infrastructure continues to age, PG&E needs to pick up the pace significantly to maintain the integrity of the system and to promote public safety. PG&E uses age, materials, seismic factors, and gas leaks to identify and prioritize gas mains for replacement. In addition to gas main replacement, the program covers related service replacement and meter relocation work.

PG&E prioritizes all gas pipeline replacement projects based on a risk determination that includes the probability of a leak on each section of pipe and the potential consequences of that leak. Each section of pipe is assigned a priority value corresponding with this probability and consequence of a leak. The company maintains a database of GPRP pipe and updates the priority values at least annually.

In addition to the Gas Pipeline Replacement Program, PG&E has initiated two other replacement programs to improve distribution safety. In 2006, PG&E recognized an increased risk associated with copper services. Beginning in 2007 PG&E initiated the system wide replacement of copper services replacing approximately 37,000 services. PG&E is targeting the completion of copper service replacements by the end of 2013.

PG&E has also initiated the replacement of Aldyl,-A distribution pipe. Certain vintages of Aldyl-A plastic have shown a susceptibility to cracking creating the potential for gas leaks. As a result, PG&E inventoried the gas distribution system to identify the location and vintages of Aldyl-A plastic pipe and initiated a replacement program in 2012. Approximately 26 miles were replaced in 2012 and 50 miles are targeted for 2013. By 2014, PG&E plans to replace approximately 100 miles annually on a going forward basis. In total, PG&E is planning to replace approximately 1,500 miles of the approximately 5,725 miles of Aldyl-A pipe over the next 15 years.

I. Gas Distribution Asset Management Project (Pathfinder)

The Pathfinder Project is enhancing and converting PG&E's gas distribution asset data into an integrated GIS/SAP system and will provide analytical and visualization tools to enhance gas distribution asset management. This project will enhance the safety of the gas distribution system by improving the accuracy and accessibility of gas distribution asset data. This project will enable PG&E to provide better service to customers by improving the safety and reliability of the gas distribution system and by making gas distribution system information more accurate and accessible for internal work planning and execution, and external communications.

The Pathfinder Project is enabling improvements to PG&E's asset management technology tools in the following ways:

- **Integrated Asset Management** – master database of asset records and best-in-class commercial applications to support decision making
- **Improved Integrity Management** – complete gas distribution geospatial connectivity model and data set to feed and enable integrity management solution for distribution integrity management programs

- **Improved System Planning** – provide system planners and engineers with a single source of data about the underlying assets pertaining to the gas distribution system

Implementation of Pathfinder began in PG&E's Peninsula Division with the conversion of maps to the new GIS in February 2013 and Pathfinder is now live in this division. The next phase of the project is in process and includes conversion and data acceptance for Sacramento, San Francisco and East Bay locations. These locations are expected to go live in November 2013. System-wide deployment is expected to be completed by the end of 2015 with phased deployment on a division by division basis.

J. Transmission and Distribution System Controls

PG&E's Transmission and Distribution Gas Control Centers monitor and control the flow of gas across our system 24 hours a day, 365 days per year, to ensure that it is received and delivered safely and reliably to customers. PG&E utilizes an operational manual that contains the necessary documents for control room personnel to manage and operate the gas transmission and distribution systems, in accordance with the requirements outlined under 49 CFR 192.631, Control Room Management (CRM). PG&E's CRM manual contains the standard (TD-4436S), procedures, plans, and processes that collectively address how the gas control room personnel conduct their work activity under normal, abnormal, and emergency operating conditions. The CRM manual has six over-arching procedures: 1) Information Management, 2) Fatigue Mitigation, 3) Alarm Management, 4) Management of Pipeline Changes, 5) Evaluating Operational Experience, and 6) Gas Control Training Program.

1. Transmission Control Center

The Transmission Gas Control Center monitors and controls system pressure, flow and operation status utilizing approximately 10,000 SCADA points, providing oversight of all compressor stations, storage fields, pipeline interconnections, and other key pipeline facilities. Gas Transmission Control operators can control system flows and pressures utilizing approximately 800 supervisory control points. In addition, the SCADA system continually provides calculated data for approximately 3,000 other points representing system inventory, supply and demand information on the transmission system.

The SCADA system utilizes alarms to warn Gas Transmission Control of changing conditions that could escalate to abnormal or emergency conditions and provides prioritization functionality. The system provides alarm filtering based on priority, data type, and geographic location to facilitate appropriate operator action upon alarm activation. Alarm priorities are configured based on four categories: Emergency, High, Medium, and Low. PG&E also has a geographical based operating process which allows for assignment of operator responsibilities based on "north" and "south" service territory assignments.

2. Distribution Control Center

PG&E's gas distribution system covers an area of 58,000 square miles, with 826 hydraulically independent systems. Real-time distribution oversight is provided by Gas Distribution Control at approximately 292 continuously monitored distribution locations at district regulator stations and pipelines. In addition, some local distribution oversight is enabled by approximately 350 electronic recording devices which alert local on-call distribution supervisors if pressure set points are exceeded. Should an electronic recording activate, the local distribution supervisor is responsible for assessing the nature of the alert and, if appropriate,

dispatching PG&E personnel to address the situation. To monitor the balance of the distribution system, local offices collectively deploy more than 500 permanent and temporary chart recorders⁸ to record pressure data.

PG&E has created a new Gas Distribution Control Center in San Francisco that is one step in moving PG&E towards a predictive and proactive approach to system operations. In 2013, this facility will be co-located with the existing Gas Transmission Control Center, and Gas Dispatch in San Ramon to facilitate communication and information sharing, and will be staffed with full time employees. The Distribution Control Center will utilize existing SCADA capabilities and functionalities of the distribution system initially, with increasing functionality as new control room technologies are deployed and the planned SCADA system replacement goes into operation during the 2014-2015 timeframe.

PG&E plans to install approximately 700 monitoring and control devices across the service area by the end of 2013 and 3,200 devices from 2014 through 2016, for a total of 3,900 devices. Over time, the number of field monitoring locations will provide 95 percent visibility, 20 percent control of the distribution network.

3. Enhancements to Transmission and Distribution Control Centers

PG&E has significantly enhanced and expanded its SCADA visibility and control capabilities to assist in predicting and proactively managing abnormal events on the transmission and distribution system. The Automated Valve Program Implementation (described in Section V.E.2) and the creation of the Distribution Control Center are significant enhancements along with the integration of Data Historian with SCADA and GIS. These three projects are foundational to the broad initiative PG&E has undertaken to build a comprehensive controls framework implementing a control room strategy to move from a monitor and react operational philosophy to one that is increasingly predictive and proactive. With the implementation of these projects, PG&E will have the following assets and capabilities (progress on each as of May 30, 2013 is provided):

- Additional SCADA monitoring points for pressures and flows to enhance understanding of pipeline dynamics. For gas distribution, PG&E has established instrumentation (visibility) standards and has begun work on a multi-year program to meet those standards. For gas transmission, PG&E is assessing the current state of visibility while developing new standards for visibility to greatly improve operations. Subsequently, PG&E will begin work on increasing levels of instrumentation to meet the new instrumentation standards.
- Detailed SCADA viewing tools that provide a comprehensive understanding of individual pipeline conditions in real-time and the potential effects (e.g., downstream pressures and flows) if a pipeline segment is isolated, as well as provide increased understanding of pipeline configuration and constraints. PG&E is currently examining and designing new graphical display methods to indicate real-time pipeline conditions such as system inventory and pressures. Additionally, PG&E is establishing an asset framework to organize data and allow better association of data with pipeline segments. Specifications for a new SCADA system are in development and will include functionality to support this deliverable.

⁸ A chart recorder uses paper charts to record system pressures over time; typically 30 days. These are then used by engineering personnel to analyze historic usage and to forecast future capacity needs.

- Specific pipeline segment shutdown protocols to provide clear instructions on actions to be taken to quickly and effectively isolate a segment. A shutdown protocol template has been developed as well as a draft protocol for a section of pipeline with automated mainline control valves. Production of protocols for other pipeline sections will begin in June 2013 and will continue for all pipelines that will have automated or remote control mainline valves.
- Situational awareness tools, which utilize advanced composite alarming, and best practice alarm management methodology to highlight issues requiring immediate Gas Operator action. Currently, PG&E is conducting a feasibility study using data from the new Data Historian to establish process correlations and algorithms for calculating predictive indicators of pipeline problems. PG&E is also developing new techniques for aggregating and displaying alarms and alerts to allow gas operators to better recognize, analyze and respond to abnormal operating conditions before alarms occur.
- Interactive tools that will allow gas operators to quickly access GIS physical pipeline information in relationship to SCADA points, and to geographically locate SCADA points. PG&E is currently implementing a GIS application to show physical pipeline locations which includes capability to overlay alarm locations in relationship to the pipeline. Physical data are being collected for all pipeline assets and will be fully incorporated into the GIS system as improvements to the GIS system are made. GIS system improvements will be under development through 2014, and once improvements are completed, GIS-based pipeline information will begin to be available to the control center.
- Training simulation tools to prepare gas operators for potential pipeline rupture scenarios. PG&E is developing an on-line simulator to provide training scenarios based on actual operating conditions. Training scripts based on actual occurrences of abnormal and emergency operating events, including line rupture scenarios are also being developed. Metrics for analyzing operator responses to events are being developed.

PG&E has also conducted a best practice review of SCADA systems throughout the industry. PG&E hired an external consultant to review and compare its SCADA system to other gas pipeline company SCADA systems. Some key takeaways were: (1) upgrade our SCADA system to take advantage of expanded functionality of newer systems; (2) the company's Valve Automation program is a good starting point for leak/rupture detection and should be further enhanced with investigation of online simulator tools and expanded rate of change alarming (ROC); and (3) move towards SCADA displays that improve operator situational awareness by focusing operator attention on developing abnormal situations. PG&E is implementing these takeaways in addition to other recommendations from the review. PG&E will continue to assess the effectiveness of its SCADA and control systems, including the new tools and system modifications listed above, and make improvements to ensure that operators can make informed operating decisions.

In the 3rd quarter of 2013, PG&E plans to open a new state-of-the-art gas control facility to monitor and manage its entire gas system. The co-located facility will combine Gas Transmission Control Center, Gas Distribution Control Center and Gas Dispatch functions into a single facility operating 24 hours a day. The co-location of these three functions will enable the company to increase system knowledge and situational awareness to provide superior

emergency response coordination and facilitate better communication, information sharing and monitoring.

The control centers are planned to have sufficient physical infrastructure redundancy such that no single point of infrastructure failure will affect operations. Key features of the facility design include:

- Backup power supplied by a second service line to provide two independent paths for power to critical systems
- Standby power supplied by two diesel generators outside of the facility
- Two uninterruptible power systems to provide protection from electrical faults
- An independent Heating, Ventilation and Air Conditioning (HVAC) system for the control room, with the building's HVAC serving as backup
- A "hot" backup facility in San Francisco such that control of the gas system can be maintained in the event of a catastrophic failure at the primary Control Center in San Ramon. PG&E will begin work to scope and design the final back up after transition to the San Ramon facility.

4. Operations Clearance Procedures

An important part of public safety is ensuring that the company uses a clearance procedure for gas operations. Clearance procedures are an added safety step to confirm that a plan and procedure is in place before work is performed.

The Transmission Clearance Procedure is used for work that impacts gas flows, pressures, or gas quality. If a transmission facility is to be taken out of service for repairs, a plan and procedure ("clearance") must be formalized in writing and reviewed by the field and engineering personnel scheduled to perform the work. Transmission system clearances are managed and approved by Gas Transmission Control.

For distribution, PG&E is in the process of developing the Distribution Clearance Procedure which will help eliminate work performance errors, unplanned outages, and at-fault dig-in events through a centralized review of pending work. In essence, all work associated with gas distribution facilities will require approval and/or situational awareness from the Distribution Control Center for activities impacting the gas network. Field personnel will call the control room to report a clearance and technology will be used for situational awareness of employees performing non-clearance activity.

Industry best practices are being adopted for both the Distribution Clearance Procedure and the Transmission Clearance Procedure. PG&E has developed an electronic tool to administer its clearance procedures. The electronic tool has been designed to insure the clearance process is executed in a thorough, consistent, and visible manner. The electronic tool is currently in the pilot phase in six field locations. Rollout of the electronic clearance tool will begin in June 2013 and continue for the next 12 months to all field locations.

VII. CONTINUING OPERATIONS

Public Utilities Code Sections 961 and 963 require that natural gas system operators:

- (1) Make safety of the public and gas corporation employees the top priority;⁹*
- (2) Provide adequate storage and transportation capacity to reliably and safely deliver gas to all customers;¹⁰*
- (3) Provide for effective patrol and inspection to detect leaks and other compromised facility conditions and to make timely repairs;¹¹ and*
- (4) Ensure an adequately sized, qualified, and properly trained gas corporation workforce.¹²*

PG&E has numerous programs, policies and procedures in place to identify and minimize hazards, risks, and dangerous conditions, including the following:

A. Damage Prevention

Pursuant to CFR 49, § 192.614, PG&E is required to have a Damage Prevention Program. Damage Prevention is an end-to-end process that includes the field location of underground facilities as requested through the USA One-Call system, USA ticket management, investigations associated with dig-ins, and damage claims. The marking of underground utilities is governed by California Government Code 4216 and the process is driven by industry best practices.

Damage Prevention consists of multiple processes working together to help prevent damages from third party excavation activities as described below. PG&E's Damage Prevention processes are reviewed annually.

1. Public Awareness

Public Awareness is another key process and consists of educating customers and other key audiences regarding excavation rules, laws and best practices. Efforts include, but are not limited to, sending bill inserts in the mail, making education links available on email bill pay, sending individual separate mailers, running ads in newspapers and on the radio, conducting companywide campaigns for Call 811 Before You Dig and attending USA S.A.F.E. events that involve educating excavator companies of safe digging practices and recommendations. **Attachment 12** shows the various Public Awareness outreach efforts and the modes of outreach used for each.

PG&E's Public Awareness Plan (PAP) (Utility Standard TD-4003S) includes performance metrics and guidelines for evaluating the plan and for continuous program improvement.

⁹ PUC § 963(b)(10)

¹⁰ PUC § 961(d)(3)

¹¹ PUC § 961(d)(4)

¹² PUC § 961(d)(10)

The primary objectives of the PAP include awareness, damage prevention and emergency response readiness. On an annual basis the Public Awareness Administrator or designated resource conducts a review and develops a written report that summarizes program implementation details and outreach efforts and provides an assessment of message comprehension and understanding and a summary of stakeholder feedback collected during the year. The report also provides details regarding any notable fluctuations compared to previous years. Stakeholder feedback may include:

- Survey data collected at meetings from emergency responders and excavators
- Stakeholder feedback collected through business reply cards
- Stakeholder feedback collected through phone surveys, mail surveys, online surveys, focus groups or stakeholder interviews
- Pre-Testing —reports from focus groups, employee interviews or online panels conducted to gauge message clarity and understandability of program materials.

The results will document the number of third-party incidents during the previous year, near hits and any additional data tracked by Damage Prevention that is helpful in understanding excavator needs, issues and trends. Planned program changes for the upcoming year based on recommendations provided by the Public Awareness Program Committee, employees or vendors that support the program will also be included.

2. Dig-In Mitigation

Dig-In Mitigation consists of determining the root causes of excavation damage to PG&E's facilities, identifying process improvements to reduce damages, and actively pursuing cost recovery for damage from responsible excavators through the claims and other enforcement processes. Process improvements currently underway include:

- Integration of “caution tape” into PG&E’s construction standards, which provides excavators with a tell-tale sign that gas facilities are below;
- Training of internal excavators to conduct a “pre-sweep” prior to excavation, ensuring that all structures are identified;
- Rewriting of PG&E’s “Damage Prevention Manual” to provide clearer instruction around critical steps, including troubleshooting of “difficult to locate” facilities;
- Benchmarking PG&E’s Damage Prevention program against the Common Ground Alliance (CGA) “Best Practices Guide”;
- Conducting a Lean Six- Sigma analysis of PG&E’s claims process to ensure recapture of costs associated with third-party dig-ins is one timely and in an effective manner.

3. Locate and Mark

Federal pipeline safety regulations¹³ and California state law¹⁴ require that the company belongs to, and shares the costs of, operating the regional “one call” notification system. Builders, contractors and others planning to excavate use this system to notify underground facility owners, like PG&E, of their plans. The company then provides the excavators with information about the location of its underground facilities. Information is normally provided by

¹³ 49 C.F.R. §192.614

¹⁴ Gov. Code §4216

having company personnel visit the work site and place color coded surface markings to show where any 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, three digit "811" telephone number. The California one call systems are commonly referred to as Underground Service Alert (USA).

4. Pipeline Patrol and Monitoring

Pipeline Patrol and Monitoring consists of patrolling transmission pipelines to provide continuing surveillance including evaluating any significant activities on or near the pipeline and within the right-of-ways. One of the important patrol activities is monitoring that there are no unauthorized excavations taking place close to transmission pipelines. Patrols are performed on all Class 1 through Class 4 pipelines with a mix of fixed-wing aerial, helicopter aerial and ground patrol methods on a quarterly basis at a minimum, which exceeds the federally mandated patrol standards¹⁵. PG&E also performs patrols on its backbone transmission pipelines on a monthly basis to help protect these vital infrastructures that import most of the gas into California and provide it to population centers around Central and Northern California. Patrols may also be performed by maintenance personnel working on the pipelines when they observe sensitive activities. Special patrols may be requested after natural disasters or major incidents to confirm the conditions of PG&E assets.

As per the Root Cause Recommendations made by the CPSD as part of the Class Location OII (I.11-11-009) in early 2012, most of these recommendations were incorporated into PG&E's Patrol Work Procedure and a new version was distributed on August 3rd, 2012. Many of the recommendations were used in their entirety and all patrollers were retrained and their Operator Qualifications were renewed starting in fourth quarter 2012.

All pipeline operators are required by 49 CFR, Part 192.613 to have a procedure for continuing surveillance of their facilities to determine and to take appropriate action for safe operations and changes in class location. The surveillance of pipeline facilities include pipeline patrolling as described in this plan, and in PG&E's procedure TD-4412P which requires an annual class location review of gas transmission and gathering pipelines (see Section VIII.G for Class Location).

PG&E's recent accomplishments in the area of Pipeline Patrol and Monitoring include improving class location verification by conducting an annual system-wide review of transmission pipeline class location designations; updating the digitized structural layer based on aerial photography; reviewing the results and finalizing map updates. Additional accomplishments include revising the standards and procedures for pipeline patrolling and continuous surveillance of class locations; implementing new guidelines for aerial patrols and reporting; and increasing and enhancing employee training on all class location procedures and reporting methods.

5. Pipeline Markers

CFR 192.707 requires PG&E to provide line markers and warning information for gas facilities. Procedure TD-4412-P09 outlines PG&E's process for installing and maintaining pipeline markers in compliance with federal requirements.

¹⁵ 49 C.F.R. §192.705 – Class 1 and 2 must be patrolled at least annually; Class 3 must be patrolled at least two times per year; Class 4 must be patrolled at least quarterly.

Pipeline markers are used to indicate the approximate location of the respective pipeline along its route. The markers are signs on the surface above or near the natural gas pipelines located at frequent intervals along the pipeline right-of-way. The markers can typically be found at various points along the pipeline route including highway, railway or waterway intersections and other such prominent locations. These markers display the name of the operator and a telephone number where the operator can be reached in the event of an emergency.

B. Supplier Quality

The purpose of Supplier Quality Assurance (SQA) is to establish procedures, practices and expectations pertaining to the quality of Transmission and Distribution products purchased by PG&E. The requirements set forth assure consistent quality based on processes for supplier approval, product approval, receiving inspection, supplier audits, product nonconformance resolution, and supply base scorecards for key suppliers.

The programs that comprise the overall quality system are varied, inter-related and generally involve engagement activity from materials personnel, field personnel, standards engineering, purchasing personnel as well as quality engineers and inspectors.

1. Distribution Gas Products

For the distribution system, PG&E maintains a database of all products that have been identified by standards engineering as safety significant. These products have inspection plans that are routinely reviewed for updates based on revisions to the associated engineering standards. All products that require inspection are inspected according to the documented inspection plan. No nonconforming product is allowed into stock.

If a product fails at receiving inspection or in the field and that failure appears to be part of a trend or may be repetitive, PG&E Supplier Quality Engineers work directly with the manufacturer to resolve the issue through root cause analysis and corrective action plans. The nonconformance issues are identified and documented in the Material Problem Reporting (MPR) system. SQA manages the MPR system which is available to all personnel at PG&E to allow employees to document any defective or suspect defective material including tools and gas carrying products.

The MPR allows trends to be identified in a timely manner so that actions can be taken with emerging material problems. The system is used by field employees and receiving inspection personnel. Each write up is fully reviewed and responded to by an engineer. The submitter of the MPR and the writer receives feedback from that engineer in written form.

If it is determined the nonconformance issue may be related to the supplier, then a Supplier Corrective Action Request (SCAR) is issued requiring product containment and a corrective action plan. A Supplier Quality Engineer will determine if the supplier's response and corrective actions are adequate. All key suppliers have their quality performance measured on a continuous basis. The measurement process is an industry recognized system called Defective Parts Per Million (DPPM). All new suppliers, production products, and tooling must first be approved by a team review of their quality processes per PG&E's standard TD4001P-04.

2. Transmission Gas Products

The SQA procedures and systems for procured transmission products is the same as for distribution products except in the area of inspections. Transmission products do not pass through a PG&E receiving location and therefore a receiving inspection is not performed.

Instead, all transmission products undergo source inspection at the supplier's site. Due to the difference in the inspection location, a DPPM score is not produced because is not accessible from the inspection site.

C. Odorization

All gas entering PG&E's transmission and distribution systems is odorized to meet the standards set forth by CFR 49 Part 192.625 which requires that gas is odorized such that it can be readily detected by a person with a normal sense of smell. PG&E operates and maintains numerous odorizers throughout the system to inject the proper amount of odorant into the gas system.

To confirm that the gas is properly odorized PG&E conducts periodic odor intensity (sniff) tests at key points in the system (Standard TD-4570S). In addition, online sulfur analyzers continually monitor the gas at critical locations to ensure there is sufficient odorant in the gas stream.

All deviations in odor intensity are quickly addressed to ensure the safety of PG&E's customers.

D. Pipeline Pathways

PG&E is also implementing the Pipeline Pathways program with the objective of reducing pipeline risk through the following:

- **Pipeline Centerline Survey**
Involves conducting a centerline survey of all 6,750 miles of transmission pipeline in 2013 using precise mapping tools with Global Position System (GPS) coordinates and entering the GPS coordinates into a new Geographic Information System
- **Encroachment Clearance**
Locating, staking, and mapping the center of the pipeline and checking the area above the pipeline for any structures or vegetation that could interfere with PG&E's ability to maintain, inspect and safely operate the pipeline. This is followed by remediation of any such encroachments deemed unacceptable for the safe maintenance and operation of the pipeline
- **Vegetation Management**
Keeping PG&E's right-of-way open and free of "non-compatible vegetation" and along with structure clearing, improving our ability to respond in emergency situations
- **Pipeline Marker Installation**
Increasing the number of pipeline markers on transmission pipelines to enhance public awareness and damage prevention while increasing safety activities around pipelines by providing a clear line of sight

These efforts will strengthen PG&E's ongoing pipeline safety programs, improve the ability to identify and prevent risks to our pipelines, and give PG&E better access to inspect, test and maintain pipelines.

E. Cathodic Protection

Buried carbon steel facilities including PG&E's steel gas pipe have a natural tendency to corrode. Corrosion on gas piping systems can contribute to leaks and catastrophic pipe failures.

Leaks caused by corrosion decrease system reliability, increase maintenance, shorten the useful service life of pipe and create public health and safety risks. In the case of steel gas lines, the pipe is coated or wrapped before installation, and then cathodic protection is applied in order to prevent corrosion of the metal surface in soil by applying a direct current from an anode to the facility being protected.

PG&E sends corrosion mechanics to physically visit each “pipe-to-soil” location at least six times per year to identify and repair cathodic protection areas (CPA) that are not working properly (Standard O-16).

PG&E also began installing devices to allow remote monitoring of the cathodic protection systems. This will allow for continual visibility into cathodic protection systems and alerts will be sent to the corrosion mechanic(s) within three days of a “down area.” Additionally, this technology, through its database properties, will allow PG&E to become more informed of system and local trends, both in general as well as for specific CPAs.

F. Seismic Considerations

Where appropriate, seismic or geotechnical conditions are considered as part of the design of a particular pipeline, and PG&E employs licensed engineering professionals with the appropriate knowledge and experience to perform the design. PG&E incorporates ground movement information into GIS and that information is used to identify if there is a "potential for ground movement". This information is updated annually to ensure it is up to date. Risk mitigation for transmission pipelines may include reroutes, installation of isolation valves, and automated or remote control valves.

G. Leak Survey

Pipeline safety regulations require PG&E to conduct periodic or routine leak surveys on its distribution and transmission systems to find gas leaks. The frequency depends on the local conditions where the pipe is installed and the material or operating condition of the pipe itself. Leak surveys are conducted at regular intervals throughout the gas transmission and distribution systems. Standard TD-4110S outlines PG&E’s requirements for the leak survey and detection program and summarizes the standards and guidelines for leak survey work.

Surveyors conduct gas leak surveys on groups of transmission pipeline facilities with a common purpose or geography, as opposed to surveying facilities according to geographic locations and maps. Surveyors in the field check gas facilities line by line, from one end of a pipeline facility to the other, on regular intervals. PG&E’s current leak survey cycles are shown in **Table 3**.

Leak Survey Cycles	
Six Months	Three Years
Substations	Copper services
Annual	Cast iron mains
Business districts	Unprotected steel mains
High public assemblies (e.g. schools)	Five Years
Atmospheric exposed mains	All others
Bare steel mains	

Table 3

PG&E has proposed through the General Rate Case (2014-2016) implementing several leak survey initiatives that will result in more leaks being identified. These initiatives include:

- Testing the Picarro Surveyor™ (described below) in one division in 2013, and depending on the pilot results, three divisions in 2014, six divisions in 2015 and 10 divisions in 2016;
- Moving from a 5-year to a 3-year survey cycle starting in 2014;
- Using the Picarro Surveyor to perform annual surveys of high-risk pipe starting in 2014; and
- Repairing, instead of rechecking all above ground Grade 3 leaks.

PG&E has acquired new technology to more efficiently conduct leak surveys. Multiple Leak Survey Detection Equipment and Survey Grading Equipment have been upgraded with an all-in-one Heath Detecto Pak-Infrared (DP IR)™ instrument that self-calibrates, detects gas leaks with fewer false positives, grades leaks, and has wireless communication ability to transfer information. This instrument is also more sensitive to the presence of gas and performs a higher level of on-board analysis to determine severity/grade of a gas leak, leading to a more accurate survey and associated grading of gas leaks.

PG&E is the first in the gas industry to investigate the use and integration of a state-of-the-art gas leak detection analyzer, The Surveyor™, developed by Santa Clara based company Picarro, Inc. This equipment is installed in a vehicle and is 1,000 times more sensitive than incumbent leak survey/detection equipment. It uses cavity ring down spectroscopy, distinguishes between natural occurring gases to that of PG&E gas, and has the potential to not only increase the efficiency of leak survey, but to find gas leaks at a greater rate than incumbent equipment. Unlike incumbent leak detection instruments, The Surveyor™ picks up trace molecules while driving through neighborhoods and analyzes them for detection of natural gas.

H. Leak Repair

All gas leak indications are graded based on a number of factors, including the amount of gas present, the proximity to structures, whether the below ground leak is covered wall-to-wall by concrete or other permanent covering, and whether or not the leak is above- or below-ground. PG&E personnel classify leaks into four grades based on the severity and location of the leak, the hazard the gas leak presents to persons or property, and the likelihood that the leak will become more serious within a specified amount of time.

- **Grade 1** leaks (also referred to as “hazardous” leaks) represent existing or probable hazards to persons or property and require immediate repair or continuous action until conditions are no longer hazardous.
- **Grade 2+ (Priority Grade 2)** leaks fall below Grade 1 criteria and above Grade 2 criteria. These leaks are non-hazardous to persons or property at the time of detection, but still require a scheduled priority repair within 90 days or less.
- **Grade 2** leaks are non-hazardous to persons or property at the time of detection, but still require a scheduled repair because they present probable future hazards. Grade 2 leaks must be repaired within 15 months, and rechecked every six months until repaired.
- **Grade 3** leaks are non-hazardous at the time of detection and can reasonably be expected to remain non-hazardous. They are re-surveyed and monitored annually, or no later than 15 months, but historically not scheduled for repair (unless leak

indications change which qualifies the leak as a Grade 1, Priority Grade 2 or Grade 2 leak).¹⁶

PG&E's grading rules exceed industry standards, as set by the ASME GPTC Guide for Gas Transmission and Distribution Piping systems, in that PG&E uses a Grade 2+ category with a scheduled priority repair within 90 days.

PG&E has a trained and operator qualified workforce that finds and repairs leaks using acceptable industry repair methods and procedures. While some leak repair work is completed on above ground facilities, many leak repairs require excavation to below the surface infrastructure facilities. All work performed is documented for completeness.

PG&E is now responding to leaks faster than ever before – and surpassing industry averages. In March of 2013, PG&E's average response rate to calls from customers reporting gas odors was 19 minutes, compared to an average response time of more than 30 minutes in 2012. Benchmarking against the industry shows that PG&E has moved from the bottom of the pack to one of the top responders in the country.

I. System Pressure and Capacity

PG&E designs and operates its gas system to ensure safe pressure regulation and adequate gas supplies. A focused plan for pressure regulation includes extensive data gathering, root cause analysis of any over pressure event, and a corrective action and improvement plan that includes evaluating equipment set points and SCADA alarm points. (An over pressure event is defined as a validated pressure increase of any amount above Maximum Allowable Operating Pressure.

PG&E's pipeline capacity is sized to provide all core customers with uninterrupted service on a one-day-in-90-year cold temperature design day referred to as an Abnormal Peak Day (APD) and to provide all customers, including noncore, with uninterrupted service on a one-day-in-two-year design day referred to as a Cold Winter Day (CWD). APD and CWD are based on conditions that have actually occurred on PG&E's system.

Customers value service reliability and there can be significant public health and safety risks associated with insufficient capacity. 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 such as outdoor grills and barbecues. 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 can affect electric generation, which during very hot weather can also result in safety concerns.

PG&E's pipeline capacity planning requirements are outlined in Standard TD-5429S (Gas Transmission and Distribution Systems Capacity Planning Requirements). The standard is supported by a companion document, TD-5429P-01 (Gas Transmission and Distribution Systems Capacity Planning Procedures).

Under the framework provided in these documents, PG&E routinely and systematically studies its storage, transmission, and distribution systems to ensure capacity is adequate to meet design day criteria. PG&E's Gas System Planning Department (GSP) obtains information from a variety of sources, including operational data, other PG&E departments, government agencies, planning commissions, regulatory proceedings, and news reports to determine

¹⁶ As discussed below, one of PG&E's new leak repair initiatives is to repair, rather than resurvey, leaks on above-ground services.

possible load growth and other potential changes that may affect system capacity requirements. In addition, systems are studied as needed to ensure that planned pipeline operations such as in-line inspection, pressure-testing, maintenance, and repair are managed for minimum impact on capacity.

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

As part of PG&E's Pipeline Safety Enhancement Plan (PSEP) and efforts to reduce overpressure events, PG&E analyzed its transmission systems to determine the feasibility of reducing normal operating pressure on systems identified by the PSEP Pipeline Modernization Program Decision Tree by as much as 20.0 pounds per square inch gauge (psig) below the Maximum Operating Pressure (MOP), and reducing over-pressure protection by as much as 5.0 psig below MOP, to create a margin of safety against overpressure events. Pressure is a significant driver of pipeline capacity, so it is necessary to conduct hydraulic studies on each system to ensure that design day criteria can be met at the proposed regulator set point. Consistent with the objective of safety, as of January 2013, pressure has been reduced in gas transmission lines to the extent design day criteria can still be met. Similarly, PG&E has evaluated and reduced pressures in its gas distribution systems where possible to provide increased separation between pressure control set points and MOPs.

In 2013, Gas System Planning (GSP) launched its Network Investment Plan program. Under this multi-year program, GSP will analyze PG&E's many gas systems in a long-term, holistic manner to optimize system design. The objective is to ensure that the various safety-related pipeline efforts including pipe replacement, in-line inspections, hydrotests, valve automation, and station work are incorporated efficiently into design work driven by other factors such as future growth over a 10- to 20-year time horizon. This long-term planning effort is also intended to wring out any existing design inefficiencies such as multiple short-run diameter changes that inhibit pigability and potential safety risks such as excessive manual winter operations and operating with little margin of safety against overpressure events. GSP identified ten distribution systems and four transmission systems as priorities for study in 2013.

J. Workforce Size

Having an appropriately sized workforce and access to qualified contractors is key to performing work safely and ensuring the safety of our gas system. The size of the workforce is determined by the work needed to address public safety, asset reliability, priority and risk. All proposed projects or programs are risk ranked and prioritized. Once approved, funding and resources, i.e., employees and contractors, are deployed to perform the works. A high level process flow is shown in **Figure 7**.

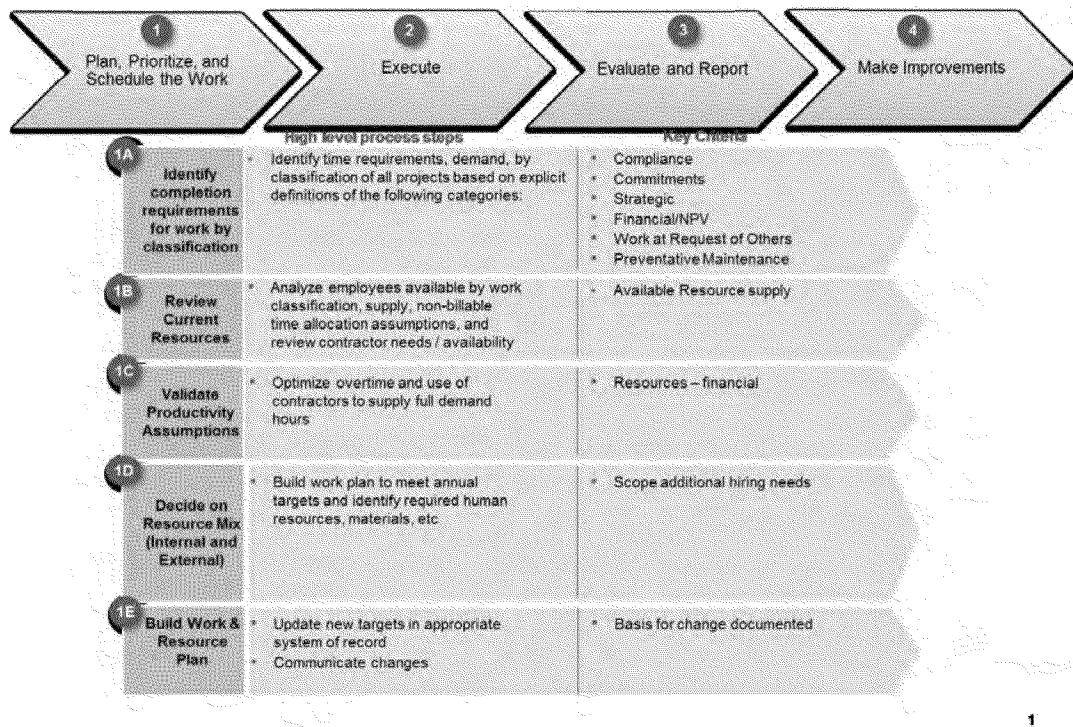


Figure 7

PG&E continually works to identify resource needs, and recruits, hires and trains professionals from throughout the industry. PG&E's gas workforce strategy is shown in Figure 8.

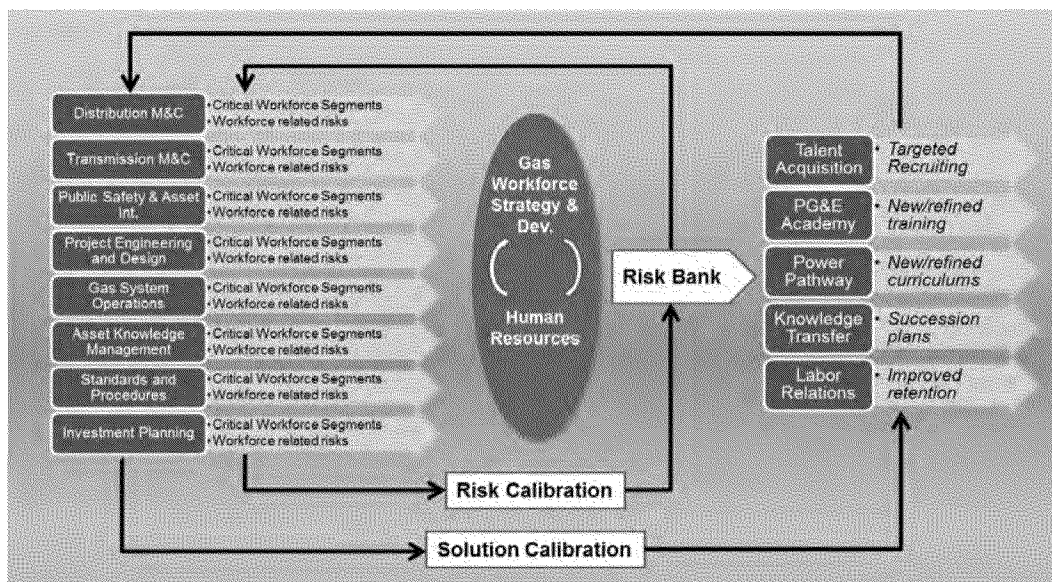


Figure 8

Through 2014, PG&E plans to hire an additional 1,400 gas employees. This increase in Gas Operations employees supports the focus on safety and compliance through the successful execution of operating improvements and investment plans for both gas transmission and distribution assets.

K. Employee Training

The cornerstone to ensuring PG&E's gas facilities are designed, constructed, maintained, and operated in a safe and reliable manner is maintaining a workforce of highly skilled, competent and experienced technical employees. PG&E conducted a comprehensive benchmark study in the fourth quarter of 2011 through the first quarter of 2012 to compare PG&E gas training to best-in-class,¹⁷ and developed an extensive plan to elevate the quality of all PG&E gas training. This study yielded eight areas of focus of which PG&E is working to implement (or has implemented).

As part of this study, interviews with PG&E gas field personnel were conducted. Recommendations being implemented in direct support of employee training include:

- Developing programs that support employees throughout their career
- Broadening technology solutions and leveraging curriculum external to PG&E
- Implementing continuous training improvement processes

To support the enhanced technical training, Gas Operations is building an advanced technical training facility designed to provide enhanced learning experiences and "real world" training scenarios in a controlled and safe environment. The training facility is currently targeted for completion in 2015.

Prioritization of training programs improvements is determined and driven by regulatory changes, new tools and instruments, standards and policy changes and greater Operator Qualification requirements. PG&E has identified approximately 100 courses that will require development or significant expansion during 2012 to 2016. Improved training programs, curriculum and materials, and qualified instructors are being developed. Improved and new courses in progress or recently completed include training for hydrostatic testing, in-line inspections, new utility worker and construction work procedures.

L. Operator Qualifications

The PG&E Gas Operator Qualification (OQ) Plan requires all individuals who operate and maintain pipeline facilities meet specific safety requirements (including meeting Title 49 Code of Federal Regulations (CFR) Part 192 Subpart N). Employees must be qualified, and able to recognize and react appropriately to abnormal operating conditions that may indicate a dangerous situation or a condition exceeding design limits.

PG&E's current OQ standard (S4450) identifies required operating and maintenance tasks, provides guidance for achieving compliance with the requirements of 49 CFR Part 192 Subpart N, establishes qualification methods for performing covered tasks on a gas pipeline facility and identifies covered tasks/subtasks.

Testing requirements include both written and work performance evaluations. The written test verifies that the employee understands the standards and procedures, and the performance evaluation verifies the application of the employee's knowledge. PG&E continuously monitors the status of employees who must be qualified, and will be implementing improvements for tracking and reporting.

PG&E is in the process of publishing an OQ standard that will replace the current OQ plan. Publication is expected by June 30, 2013. The new standard includes:

¹⁷ For the purposes of this benchmarking effort, "best-in-class" was defined as "Technical Training Best Practices found among peer Utilities in the natural gas transmission and distribution industry."

- Identifying approved evaluation methods for both initial and subsequent qualifications.
- Setting requalification intervals at 3 years, not to exceed 39 months, to the date, from the previous qualification
- Specifying that all evaluation methods are administered in English
- Clarifying that the approved Span of Control ratio for an operator qualified individual to oversee the work of other non-qualified personnel is 1:1
- Requirements for suspending or removing an OQ
- Specifying the responsibilities for communicating changes in company guidance documents that affect the OQ program
- Provisions for addressing OQ personnel acquired as part of a merger or acquisition of another company
- Language to address the OQ expiration term for contract personnel

As part of the new standard, seven new procedures have been developed:

- Procedures defining OQ administration
- Procedures addressing roles and responsibilities and scheduling of OQ evaluations
- Procedures documenting the evaluation processes
- Procedure documenting the OQ suspension process and requirements

M. Contractor Safety and Oversight

PG&E utilizes contractors to support business needs and requirements. As such, contractor safety and oversight is essential to ensuring that contractor performance meets PG&E's expectations. PG&E contractors must complete safety plans and conduct all work in a manner that safeguards workers, and the public from injury. Contractors who perform physical work on PG&E's gas facilities must also possess all applicable Operator Qualifications (OQ).

PG&E's safety oversight is applied throughout PG&E's sourcing, contracting and work performance processes. PG&E evaluates and monitors contractors' safety practices and safety performance during the initial qualification of a contractor, during the competitive request for proposal process and during the performance of work.

All contractor performed work must be completed in compliance with all applicable federal, state, and local laws, rules, and regulations (i.e.,) as well as PG&E standards, including:

- Occupational Safety and Health Standards
- California Division of Occupational Safety and Health
- The United States Department of Transportation (DOT) Operator Qualification guidelines required under 49 CFR 192 and 195,
- PG&E's Natural Gas Operator Qualification Plan
- PG&E's Supplier Code of Conduct

In 2013, PG&E established the Contractor Safety Management Program and Contractor Safety Department within the Safety Organization with the purpose of helping to select and monitor contractors. The Contractor Safety Department serves as the interface between PG&E lines of businesses and contractors. The department also ensures all lines of business are aligned with the Contractor Safety Guidance Document (**Attachment 13**)

Also in 2013, PG&E implemented Phase 1 of the Contractor Safety Program which is a pilot of safety performance results of 25 suppliers and contractors. Evaluation of this pilot will occur in 2013 with Phase 2 expansion of this program in 2014.

1. Contractor Oversight of Gas Transmission Construction

The Gas Transmission Construction Management team is responsible for the safe completion of construction projects in accordance with the project design, PG&E Standards, applicable permits and regulatory requirements. Each project constructed by construction contractors is overseen by a construction manager, a lead inspector, welding and coating inspectors, and in some cases utility inspectors. Each element of the work is inspected and the inspection records are tracked and maintained. Every weld is visually inspected and X-rayed according to the standards and recorded and logged on weld maps and daily welds summary inspection forms. Each material component and field applied coating is also inspected to ensure compliance and then recorded and mapped on the appropriate quality control forms. At the end of the project, the entire as-built package including all of the complete and accurate quality and inspection records receive a final quality assurance check prior to being turned over to mapping for input into the electronic data system storage.

N. Quality and Improvements

PG&E's Quality and Improvement (Q&I) department is responsible for centralized Quality Control (QC) and Quality Assurance (QA) activities. The QC activities include quality verifications through field assessments either in real-time (as work is being performed) or after-the-fact. PG&E currently has six fully operational QC programs for Leak Survey, Leak Repair, Locate and Mark, Distribution Construction, Transmission Construction, and Field Service. QC activities will continue to be expanded through the development of additional programs as needed and through evolution of existing QC programs in order to continuously achieve the greatest amount of risk reduction.

QA activities include audits of PG&E's processes and programs. QA activities also include conducting issue analysis and assessments to provide recommendations for improvement and building an overarching Corrective Action Program (CAP) for Gas Operations which complies with the PAS 55 certification requirements. Gas Operations' CAP is described in Section X.A.

VIII. EMERGENCY RESPONSE

Public Utilities Code Section 961 establishes several goals for natural gas system operators relating to emergency response:

- (1) Provide for appropriate and effective system controls, with respect to both equipment and personnel procedures, to limit the damage from accidents;¹⁸*
- (2) Provide timely response to customer and employee reports of leaks, hazardous conditions, and emergency events;¹⁹and*
- (3) Prepare for, or minimize damage from, and respond to, earthquakes and other major events.²⁰*

¹⁸ PUC § 961(d)(5)

¹⁹ PUC § 961(d)(6)

²⁰ PUC § 961(d)(8)

PG&E's policies and procedures have been developed and 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 NIMS principles, including the use of the Incident Command System (ICS), to protect the public and to restore essential utility service following such emergencies;
- Help alleviate emergency related hardships
- 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 responders, and others
- **Restore** gas and electric service and power generation
- **Restore** critical business functions and move towards business as usual.
- **Inform** customers, governmental agencies and representatives, the news media, and other constituencies

A. Company Emergency Plan

PG&E's Company Emergency Plan (CEP) (**Attachment 14**) provides a broad outline of PG&E's organizational structure and describe the activities which will be undertaken in response to emergency situations. The CEP will be used during emergencies by presenting a response structure with clear roles and responsibilities and identifying coordination efforts with outside organizations (government, media, other electric and gas utilities, essential community services, vendors, contractors).

Details of how PG&E accomplishes the functions described in the CEP are found in topic-specific plans prepared by the individual departments and lines of business. PG&E maintains over 18 Emergency Operation Plans (EOPs) for various functions, including the Gas Emergency Response Plan (Section VII.B.1) which provides detailed information about PG&E's planned response to gas transmission or distribution emergencies. These individual EOPs are updated annually. In addition to the EOPs, PG&E maintains approximately 48 Business Continuity Plans (BCPs), which describe how PG&E will continue essential business operations in the event of a disruption to facilities, technology or personnel.

The Incident Command System (ICS) is a systemic tool used for the command, control, and coordination of emergency response. The ICS provides a common framework within which people (internal and external) can work/communicate together effectively. PG&E uses this system to manage emergency response, consistent with the California Standardized Emergency Management System (SEMS) and the National Incident Management System (NIMS). Below are listed basic ICS organizational positions:

- Command
- Joint Information Center (JIC)
- Operations
- Planning & Intelligence
- Logistics
- Finance

B. Response to Emergency Events

In response to Level 3 type emergency events (extreme events that require multi-regional, division or district coordination), PG&E can activate an Emergency Operations Center (EOC). The EOC is a designated location at which key personnel meet to coordinate or command response to an emergency. PG&E's Gas Emergency Preparedness (GEP) department has established pre-assigned gas EOC on-call teams skilled in gas operations for response to a commodity-specific event. The EOC is equipped with all necessary equipment, supplies, information and data systems, backup power, and other resources needed to conduct prompt and effective emergency response activities. The EOC has a designated backup facility in the event that the primary EOC is not available or accessible.

For Level 1 or Level 2 emergency events (events occurring within normal business hours or emergencies that require 24/7 operational response), PG&E can activate local Operations Emergency Centers (OEC) or Regional Emergency Centers (REC). These emergency centers manage the work in a defined geographic region, and are responsible for directing resources to implement actions and for reporting status and progress through the emergency center chain of command, ultimately to the EOC.

1. Gas Emergency Preparedness and Response

The GEP department supports coordination activities, training and communication with city/county/local first responders within PG&E's service territory. A primary function of the GEP department is to provide pipeline and general safety training to local/state/volunteer first responders, as well as share the Gas Emergency Response Plan (GERP) with the appropriate community partners. The GEP team is actively engaged in all facets of emergency preparedness planning, training (for both internal and external responders), performance measurement and regulatory compliance. Responsibilities of this department include maintenance of the GERP to assist PG&E personnel in responding safely, efficiently and in a coordinated manner to emergencies affecting gas transmission and distribution systems. Additionally, the GEP team coordinates After Action Reviews (AAR) of unplanned gas releases, program responsibility for gas operations Business Continuity Plans (BCP), deployment and governance of PG&E's fleet of Mobile Command Vehicles (MCV), functional/field and table top exercises and drills, and participation in industry benchmarking on Emergency Management solutions.

The GERP (**Attachment 15**) describes the roles and responsibilities of PG&E's emergency response personnel, which includes a single person who assumes command and designates specific duties for the SCADA staff and all other potentially involved company employees.

PG&E's 911 Notification Process requires PG&E's control room operators to make the 911 notification immediately based on the following SCADA alarm conditions:

- relief **valve open alarm** venting gas to atmosphere
- automatic shut off **valve closed alarm** indicating isolation of a section of pipeline
- activation of a **pressure drop – rate high alarm** indicating a high differential across one of the newly installed remote control isolation valves

- activation of a ***Lo-Lo pressure alarm*** indicating possible pipeline rupture (confirmed valid by verification of upstream and downstream pressure sites and correlated supply source metered flow increase)

The PG&E 911 Notification Process has triggers to immediately make 911 notifications based on a field employee and/or an external public entity communicating information concerning a transmission or distribution facility involvement in a natural gas related event.

Once the SCADA alarm conditions have been triggered and/or non-SCADA based information has been received suggesting an emergency operating condition, PG&E follows a detailed procedure that explicitly requires Gas Control to notify 911 Emergency Response Centers.

In order to improve focus on real time monitoring, PG&E has implemented geographical based responsibilities for gas system operators. Transmission control operators are assigned to monitoring north or south portion of the system. For distribution control, the assignments are broken out by Northern, Bay, Central Coast, and Central Valley. At any given time, operators are now responsible for monitoring their assigned areas only. Additionally, an enhancement to PG&E's SCADA system has been completed which prioritizes alarms for appropriate operator action upon activation. Alarm priorities are now configured based on four categories: Emergency, High, Medium, and Low. The SCADA enhancement also provides PG&E's operators with the capability to filter alarms based on priority, data type, and geographic location.

PG&E utilizes an enterprise wide OSIsoft Pi historian system which is a data collection site for all gas SCADA data. PG&E is installing a situational awareness video wall in its new co-located Gas Dispatch Control Center allowing control room personnel to respond proactively to emerging system conditions. See Section V.I.1.

Additionally, PG&E has a fleet of new Mobile Command Vehicles (MCV) to better respond more rapidly to natural gas or electric emergencies.

2. Earthquake Response

PG&E uses Geographic Information System (GIS) based products to enhance emergency response following a significant earthquake. PG&E's Gas Transmission Earthquake Plan and Response Procedure is provided in RMI – 04 (**Attachment 16**) and the Gas Distribution Earthquake Plan is provided in RMI- 04B (**Attachment 17**). These plans describe PG&E's use of USGS data and identify service areas that are potentially impacted. The susceptibility to seismic activity and geotechnical conditions is reviewed annually, and updated to provide accurate response areas over PG&E's Service Territory.

The GERP provides guidance and information for responding to earthquake emergencies (Appendix A.2. Training Aid 7 – Earthquake). PG&E has also developed the *Earthquake Playbook* (EMER-1012M), to provide guidance on PG&E's response and recovery actions. The *Earthquake Playbook* provides an executive-level perspective on disaster conditions the company will face immediately after an earthquake, including actions it will take and how it will conduct business.

C. Information for First Responders and the Public

PG&E has launched a web portal within *pge.com* dedicated to external first responders and residential customers. Access to training materials, general mapping of gas transmission pipeline segment locations, safety DVDs, literature on school safety, and much more is

available. Enhancements have been made to some of the data available to first responders so that they can use it in real time while en route to an incident or once they have arrived on scene. For example, registered first responders now have access to more detailed characteristics of gas transmission assets, portions of the GERP, and contact information to key members of the GEP department.

PG&E has developed specific informational flyers and has issued press releases to promote safety (such as for dig-ins which potentially damage infrastructure and for customer behavior around potentially dangerous infrastructure including downed power lines). These materials are accessible through pge.com and a special safety education website at www.pge.com/safetycentral.

D. Call Center

PG&E operates a 24/7 Contact Center to receive calls from customers and emergency responders. All Contact Center representatives receive an annual training on gas emergency response procedures. Related call handling processes are housed in an online repository that is utilized by Contact Center representatives to ensure adherence to public safety and emergency procedures during any event of a gas emergency, pipeline integrity situation or threat to public safety. The Gas Dispatch Center is notified immediately of any emergency gas situation that is called into the Contact Center.

E. Service Response

Gas Field Services personnel complete emergency work related to gas leaks, carbon monoxide monitoring, customer requests for starts and stops of gas service, appliance pilot relights, appliance safety checks, regulator replacements and other gas and electric infrastructure emergency-related work. PG&E's Gas Service Representatives (GSRs) complete more than 700,000 gas service requests from customers each year. These requests include investigating gas leaks (classified as immediate response work), gas starts/stops, pilot relights, appliance checks, atmospheric corrosion work, and regulator replacements.

Responding to gas leak calls within a specified timeframe is crucial to public and employee safety and is regarded as an industry best practice. In 2013, PG&E adopted a new safety standard of responding to customer calls reporting possible gas leaks classified as immediate response within 60 minutes 99 percent of the time as well as actually responding to gas leak reports within an average of 22 minutes. PG&E now ranks in the top quartile for gas utilities nationally, based on industry benchmarking information.

GSRs use two methods to check for leaks. The first is a clock test on the customer's meter where the GSR observes the test hand for indication of possible gas leakage on the customer's house line or gas appliances. The second is a leak test where the GSRs use the Sensit Gold Combustible Gas Indicator (CGI) Model Ex-CO Plus. Procedure TD-4110P-10 details procedures for investigating reports of inside gas leaks and procedure TD-4110P-13 details procedures for investigating reports of outside gas leaks.

Third Party Emergency Response Centers ("911") and public safety agencies have a direct dedicated emergency phone line into PG&E's Dispatch Centers which connects directly with a dispatcher. The dispatcher collects all relevant facts, generates a field order and then dispatches a field technician to respond. If there is a rare instance where an emergency response center calls the General Inquiry line, the Customer Service Representative (CSR) will process the call in the same way they process a customer call and will notify dispatch.

In some situations, a Maintenance & Construction (M&C) crew may be required as well as the GSR such as the following:

- A report of a gas emergency from a customer calling the Contact Center.
- A public safety agency (e.g., police and fire) can contact PG&E dispatch directly through PG&E's dedicated emergency response line.

In either case, PG&E immediately dispatches a GSR as a first responder. Once the GSR is onsite, they will determine if an M&C crew is needed. For example, if there is a leak detected outside, if there is a structure fire, or if there is a dig-in by a 3rd party. For a reported dig-in, M&C crews are dispatched at the same time as a GSR to respond to the emergency. PG&E Standard TD-6435P-08 (Gas Outage Restoration) describes the shutdown and reestablishment of gas service as the result of a failure in transmission or distribution systems.

IX. STATE AND FEDERAL REGULATIONS

Public Utilities Code Section 961 requires that the safety plans of natural gas system operators:

- 1) *Include appropriate protocols for determining maximum allowable operating pressures (MAOPs) on relevant pipeline segments, including all necessary documentation affecting the calculation of MAOPs;²¹*
- 2) *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 (DOT) in Part 192 (commencing with § 192.1) of Title 49 of the Code of Federal Regulations;²² and*
- 3) *Be consistent with best practices in the gas industry and with federal pipeline safety statutes as set forth in Chapter 601 (commencing with § 60101) of Subtitle VIII of Title 49 of the United States Code and the regulations adopted by the DOT pursuant to those statutes.²³*

The State of California's rules governing the design, construction, testing, operation, and maintenance of gas transmission and distribution pipeline systems are specified in Commission's General Order 112-E. The Commission has incorporated Title 49 of the Code of Federal Regulations (49 CFR), Parts 190, 191, 192, 193, and 199, which govern the design, construction, testing, operation, and maintenance of Gas Piping Systems into its General Order 112-E.

PG&E has developed and implemented policies, procedures and programs that govern the design, construction, installation, operation, maintenance and determination of maximum

²¹ PUC § 961(d)(7)

²² PUC § 961(d)(9)

²³ PUC § 961(c)

allowable operating pressure for gas transmission and distribution facilities in accordance with General Order 112-E and as well as, 49 CFR Part 192. These policies, procedures and programs are updated in a timely manner as appropriate in response to changes in regulation, safety advisories, and other safety information.

A. Design

49 CFR Part 192 Subparts B, C, and D specify the minimum requirements for the material selection and design of pipe and pipeline components. PG&E's transmission and distribution pipelines and facilities are designed with approved materials that have sufficient wall thickness and/or adequate protection to withstand anticipated external pressures and loads. The pipe and facilities are also designed with materials of sufficient strength to contain internal pressures plus appropriate design and/or safety factors. Components, including valves, flanges, and fittings meet the minimum prescribed requirements specified in the regulations. The design also includes pressure relief or other protective devices to prevent accidental over pressurization. All pipeline design work with a design pressure or future design pressure greater than 60 psig must be reviewed, signed and stamped by a licensed, professional engineer registered in the state of California and competent in pipeline engineering. All design work performed by contractors is reviewed by a PG&E employee for quality and compliance.

B. Construction

49 CFR Part 192 Subparts E, F, G and J specify the minimum requirements for the construction and testing of transmission and distribution facilities, including the welding and joining of pipe and components as well as the protection of the pipe and facilities from hazards such as unstable soil, landslides, and other hazards that may cause the pipe to move or sustain abnormal loads. PG&E's transmission and distribution pipe and facilities are constructed in accordance with these requirements.

C. Installation

49 CFR Part 192 Subpart H specifies the minimum requirements for the installation of distribution service lines, service regulators, and customer meters. These requirements include specifications pertaining to the location of this infrastructure, protection from damage, and valve requirements. PG&E's service lines, service regulators, and customer meters are to be installed in accordance with these requirements.

D. Maintenance

49 CFR Part 192 Subparts M and I specify the minimum requirements for the maintenance of transmission and distribution pipe facilities along with the associated corrosion protection facilities. Maintenance activities include the patrolling of pipeline, performing leakage surveys, monitoring performance of corrosion protection systems, making repairs, inspection and testing of pressure limiting and regulating equipment, and valve and vault inspection and upkeep. PG&E maintains its pipelines and facilities in accordance with these requirements.

E. Operations

49 CFR Part 192 Subparts Land K specify the minimum requirements for the operation of transmission and distribution pipeline facilities. Operational activities include the Emergency Response Plan as well as requirements for a public awareness program, damage prevention program, control room management procedures, odorization of gas, identification of changes in

population density along certain transmission lines, and the determination of maximum allowable operating pressure including requirements for increasing the maximum allowable operating pressure. PG&E operates its pipelines and facilities in accordance with these requirements.

F. Maximum Allowable Operating Pressure

A maximum allowable operating pressure (MAOP) is established for each pipeline or piping system. The established MAOP cannot exceed the maximum pressure allowed by regulatory code as specified in 49 CFR §192.611 and 49 CFR §192.619 - 49 CFR §192.623 as applicable. Class location, design, testing and operating history are all factors that can limit the MAOP of a pipeline or system.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 became Public Law 112-90 on January 3, 2012. This law, in part, requires gas transmission operators to verify records accurately reflect the physical and operational characteristics of transmission pipeline in Class 3 and Class 4 locations and Class 1 and Class 2 high-consequence areas and then confirm the established MAOP.

PG&E's Pipeline MAOP Validation Process is described below. Through the end of April 2013, PG&E completed the MAOP validation for all transmission lines and is continuing to correct facility issues to comply with validated MAOP values.

1. Pipeline MAOP Validation Process

The Pipeline MAOP Data Validation Project validates the MAOP of each of PG&E's transmission lines (**Figure 9**). The MAOP Validation report, which is an output of the project, is based on each Pipeline Features List (PFL) and reflects the MAOP validated of each feature. The data for each feature were obtained through the review of documentation (e.g., as-builts, bills of material, etc.) of each line. In some cases conservative assumptions based on PG&E's historical standards and purchasing practices, as well as sound engineering judgment and field verification where needed.

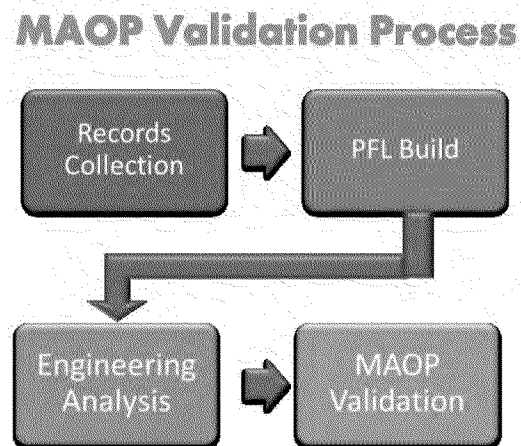


Figure 9

In the MAOP Validation report a comparison is made between the MAOP of record (MAOP-R), the MAOP of design (MAOP-D), such as component rating, and MAOP per test (MAOP-T) if

the component was strength tested. If the MAOP-R is greater than either MAOP-D or MAOP-T, a pressure reduction is implemented. In cases where no valid strength test is available, the MAOP is validated using the MAOP-D. The PFLs and MAOP Validation reports are used to prioritize the strength testing of these pipelines.

In 2011 and early 2012, as part of PSEP, and to ensure safe operation of PG&E's natural gas transmission lines, PG&E validated the MAOP of pipelines in class 3 and 4 locations and class 1 and 2 HCAs. This effort was completed at the end of January 2012. In addition, the lines validated through this effort included additional segments identified through class location changes as a result of the Class Location Study completed in June, 2011. PG&E has completed the MAOP validation for all transmission lines. On-going work consists of correcting facility issues to comply with validated MAOP values.

G. Class Location

When new structures or well defined outside areas (WDOA) are identified along PG&E's gas transmission pipeline, PG&E's Standard TD-4127S requires an evaluation of its class location. These structures are identified through ongoing surveillance or during PG&E's system wide annual class location study. The annual study must be performed each calendar year, not to exceed 15 months and supplements the existing continuing surveillance procedure. The annual study also provides additional means, independent of patrolling, to determine whether the population density has increased adjacent to the pipelines so as to trigger a potential change-up in class location.

Consistent with 49 CFR, Part 192.611, if a pipeline class change-up is identified, the MAOP of the pipeline is reviewed and action is taken to assure the pipeline is commensurate with the new class location. If a segment of pipeline is determined to be non-commensurate with the new class, but no immediate hazard exists, PG&E will remediate the pipeline by hydro testing, replacement, or retirement as described in Gas Design Standards A-34 and A-37. Confirmation or revision of the MAOP that is required as a result of the study must be completed within 24 months of the change in class location.

When a class change-up is identified on transmission pipe operating above 40 percent SMYS, 49 CFR, Part 192.609 requires that PG&E immediately initiate a study on the integrity of the pipeline segments involved.

H. Benchmarking and Best Practices

1. American Gas Association

PG&E is an active member of the American Gas Association (AGA) and participates on numerous AGA committees as shown below in **Table 4**.

AGA Participation	
Steering Committee Member	Program Coordinator
Operating Section Managing Committee	Plastic Materials Committee
Building Energy Codes & Standards	Safety & Occupational Health Committee
Corrosion Control Committee	Supplemental Gas Committee
Distribution & Transmission Engineering	Transmission Measurement Committee
Distribution Construction & Maintenance	Transmission Pipeline Operations Committee
Distribution Measurement Committee	Underground Storage Committee
Gas Control Committee	Utility and Customer Field Services Committee
Operating Safety Regulatory Action Committee	
Public Awareness	Contractor Management and Quality
Combine GPS/GIS with Work Management	Damage Prevention
Technical Training and Knowledge Transfer	Odorization

Table 4

Additionally, PG&E responds regularly to AGA SOS requests. These are topic-specific survey requests requested by gas companies through AGA. PG&E typically responds to all SOS requests and also utilizes the process when information about a particular topic or area is needed.

2. INGAA (Interstate Natural Gas Association of America (INGAA))

PG&E is an active participant in the INGAA organization and provides support and input into INGAA's Pipeline Safety Committee. PG&E has been actively engaged in assisting the INGAA Integrity Management Continuous Improvement (IMCI) effort and has incorporated many of the proposed improvements into its emergency response and integrity management processes.

3. Pipeline and Hazardous Material Safety Administration (PHMSA)

PG&E has a procedure (TD-4012P-01) to ensure appropriate response to all PHMSA advisories and any proposed or final rulemaking notices from other regulatory agencies. The procedure expedites reviewing, assigning, and tracking of all gas transmission and distribution-related advisory bulletins and proposed or final rulemaking notices from any regulatory agency in a timely manner. These include all bulletins and notices affecting engineering, construction, operations, maintenance, and emergency response activities or procedures. Additionally, the procedure will ensure that any actions or changes needed to address the bulletins or notices are identified and completed in a timely manner.

4. Common Ground Alliance

PG&E is a member of the Common Ground Alliance (CGA) which is a member-driven association dedicated to ensuring public safety, environmental protection, and the integrity of

services by promoting effective damage prevention practices. CGA is comprised of 7 working committees:

- Best Practices
- Technology
- Data Reporting & Evaluation
- Educational Programs & Marketing
- One Call Systems International
- Regional Partner
- Stakeholder Advocacy

CGA provides a best practices study each year that PG&E uses to benchmark and align policies and procedures in damage prevention.

The California Regional Common Ground Alliance (CARCGA) is a regional partner of the national CGA. CARCGA is committed to the prevention of damage to underground installations and the resulting interruption of vital services, safety risks, accidents and fatalities by promoting the use of best practices. Participation allows PG&E to maintain active relationships with other utilities, regulators and industry groups. Several examples of how PG&E has benefited from participation in the CARCGA include:

- Comprehensive One Call Law Process presentation to educate stakeholders in California.
- Development of a proposed Damage Prevention Model for California law makers to provide guidance on implementation of the program.

5. Western Energy Institute

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 participates on several committees and the company's president is a member of the Board of Directors.

6. Innovative Industry-Leading Technologies

PG&E has gathered information from across the industry to identify and implement the latest innovative technologies and practices. Last year, PG&E became the first utility to use an advanced, car-mounted leak detection device called Picarro (described in Section VI.G). PG&E has also collaborated with UC Davis to develop aerial leak survey technology using a fixed-wing aircraft and deployed new equipment to our distribution leak surveyors, including tablet technology and an instrument that uses infrared technology to pinpoint gas leaks with greater accuracy.

This year, PG&E will be the first utility to demonstrate the untethered In Line Inspection robot Explorer 30-36" developed by the NYSEARCH consortium in a live pipeline. PG&E also started to use the smaller version of this robot (Explorer 10-14") in one of its pipelines. This new technology will allow inspection of pipeline sections that cannot be inspected with traditional PIGs.

PG&E also introduced a corrosion and mechanical damage measurement device called EXAscan. This handheld laser scanner produces a highly accurate, 3-D, color-coded view of the pipe dramatically improving the productivity and accuracy of its in-the-ditch inspections.

In addition, PG&E is currently working in collaboration with a large number of partners on more than 50 R&D and Innovation projects including: leveraging its smart meter telecommunication infrastructure to transport monitoring data from distributed sensors on its system to its control rooms, developing an automated Non Destructive Evaluation tool to check the quality of butt fusion joints, testing a stationary methane detection system able to trigger alarms in case of gas leaks, and assessing different solutions to identified construction activities that can potentially damage pipelines in the ground.

7. Collaboration with Other Gas Providers

Employees within the Gas Operations organization are constantly meeting with their peers in formal and informal meetings to discuss practices, procedures, common issues and best practices. For instance in February 2013, PG&E along with The Mosaic Company cohosted a group of 12 gas utilities to discuss technical training challenges, solutions and best practices. These and other similar meetings create a means of sharing information and understanding among utilities.

VII. EMERGING ISSUES

Public Utilities Code Section 961 provides that the safety plans of natural gas system operators should also include any additional matter that the Commission determines should be included in the plan.²⁴

PG&E has worked closely with the CPUC to address the deficiencies identified in the first revision of PG&E's Gas Safety Plan. PG&E will continue to work with the CPUC as part of PG&E's revision process to address any additional matters the CPUC might determine should be part of future revisions to the Gas Safety Plan. Likewise, PG&E's will take appropriate steps to identify matters that should be included in future revisions of the Gas Safety Plan.

PG&E stays current on emerging issues within the industry through active participation in industry associations (as described in Section VIII.H) and open communication with legislative and regulatory groups. PG&E will continue to work in collaboration with the Commission and other regulatory authorities to stay abreast of industry best practices in order to address emerging issues that may impact gas safety.

A. Publicly Available Specification 55

PG&E is pursuing a best practice asset management certification offered by the British Standards Institute under its PAS 55. PAS 55 provides an objective certification and provides an independent assessment of the completeness and continuity of safety and reliability.

²⁴ PUC § 961(d)(11)

PAS 55 was first established in 2004 in response to demand from British regulators and the industry for an asset management standard. PAS 55 was adopted in the United Kingdom (UK) by the UK's Office of Gas and Electric Markets (OGEM) to ensure that public utility assets were being managed safely. It is currently used by over 50 public and private organizations in ten countries and fifteen industry sectors and is expected to become an International Standard of Operation (ISO) in 2014.²⁵

This standard outlines a 28-point specification for all types of physical assets. PAS 55 specifically requires evidence of alignment between good intentions and real, on-the-ground delivery. It ensures that the principles of safety, life cycle planning, risk management, cost/benefit, asset knowledge, customer focus and sustainability are actually delivered within the day-to-day activities of capital project design, implementation, operations, maintenance, and retirement/renewal.

To meet the standard, PG&E must develop a strategic plan for the organization and then systematically, and in a coordinated fashion, implement the plan by sustainably managing risks, assets and asset systems, asset performance, and expenditures over their defined life cycles. The standard assures alignment between PG&E's strategic plan, the gas asset management policy, standards, objectives, and specific work plans.

PAS 55 requires the creation of a strong line of sight between the highest level organizational objectives at the Board of Directors to the activities of employees in the field. It requires that PG&E's management team reviews, at least annually, the results of communications, participation and consultation with employees and other stakeholders. The certification audits employees' understanding of safe operations, maintenance and improvement processes, and verifies that there is a process in place to continuously identify and address issues.

PAS 55 encourages organizations to create a culture of continuous improvement; in order to maintain accreditation as it is imperative that the company be able to demonstrate improvements in all aspects of the Asset Management System. PG&E's quality improvements and integration of new technology will further enhance safe system operations.

Certification by an independent auditing firm is targeted for 2014. To maintain certification once it is obtained, PG&E must have annual independent audits performed of its asset management processes, and an independent recertification audit every 3rd year.

The company is committed to meeting the high international standards that PAS 55 requires, and its underlying principles of sustainable safe operating processes and continuous improvement.

²⁵ It is expected that PAS 55 will become ISO 55001 in 2014. In that event, Gas Operations would seek ISO 55001 certification and strive to become the first ISO 55001 certified gas corporation in the United States. ISO 55001 would differ from PAS 55 in the following key respects: (1) enhanced Board level engagement expectations; (2) more direction on asset management strategy development; and (3) elevated financial expectation, especially with respect to the goal of responsible asset management.

IX. WORKFORCE PARTICIPATION

Public Utilities Code Section 961 provides as follows:

The commission and gas corporation shall provide opportunities for meaningful, substantial, and ongoing participation by the gas corporation workforce in the development and implementation of the plan, with the objective of developing an industry-wide culture of safety that will minimize accidents, explosions, fires, and dangerous conditions for the protection of the public and the gas corporation workforce.²⁶

In the development of the Plan, PG&E sought feedback from employees, Union leadership, and contractors on organizational practices, existing procedures, and the ten (10) SB705 directives. Union and management employees participated in facilitated discussions; a total of six (6) focus groups were conducted. Approximately 190 issues and concerns from these discussions were documented in a comprehensive issues log (**Attachment 18**).

PG&E has taken steps to address the issues and concerns that were presented at the focus groups. Progress on many of the issues has been communicated, and continues to be communicated through various methods including emails from the executive leadership and implementation, face-to-face meetings with stakeholders, and progress reports to employees. Many of the issues raised were addressed through employee communications, while other issues have longer term fixes.

PG&E is committed to the resolution for all of these issues and will be merging this effort with the new Corrective Action Program (CAP) described below.

A. Corrective Action Program

As part of PG&E's Gas Safety Excellence strategy PG&E has implemented a risk-based Corrective Action Program (CAP). CAP collects all gas issues and ideas (including operational events, audit findings, employee feedback and improvement ideas) in a central place. Issues and ideas submitted to CAP undergo a risk-based evaluation to determine the underlying cause. The issues are then prioritized and actions are tracked through to completion.

This program will also provide a more formalized employee feedback system to allow employees and contractors to easily, and anonymously if they choose, submit Gas Operations related concerns, questions, ideas, and general feedback. Objectives of the CAP include:

- Identifying problems, issues, concerns, and opportunities for improvement.
- Evaluating, classifying, analyzing, and investigating these issues.
- Developing and implementing corrective and preventive action plans.

Items submitted through CAP can come from a variety of sources including, but not limited to, the following items:

- Safety-related conditions.

²⁶ PUC § 961(e)

- Internal, external, and third-party audit findings.
- Equipment failures.
- Regulatory violations and reportable incidents.
- Advisory recommendations.
- Overpressure events.

The CAP process (**Figure 10**) allows for rigorous problem solving so that causes are properly identified and solutions are effective in eliminating those causes. An important part of CAP is quickly sharing information and lessons learned – which will support continuous learning and improve the safety of our operations.



Figure 10

Real-time reports enable detailed analysis and trending, which can help to prevent recurrences and improve the availability of gas assets, the safety of the public and personnel, and the reliability of the gas system. CAP provides transparent tracing of issues from identification through resolution and anonymous feedback capabilities

The CAP incorporates best practices from numerous industries and sets the standard of excellence within the natural gas industry. CAP is currently being used in a pilot state for operational events and audit findings and the employee feedback functionality is expected to be available in the third quarter of 2013.

B. Compliance and Ethics Helpline

PG&E’s Compliance and Ethics Helpline is available to employees, contractors, consultants, and suppliers 24 hours a day, 7 days a week. The Helpline can be used for both guidance on conduct matters and legal and regulatory requirements or to report situations that may require investigation. Callers have the option of remaining anonymous with any call. In addition to the Helpline channel, the following methods are available to raise concerns and ask for guidance on a range of company policy topics:

- 24-hour Helpline phone service (third party managed)
- Web-based submittal service (third party managed)
- Letter, phone call, email message (including through the Compliance and Ethics Helpline mailbox), fax, or personal meeting with Compliance and Ethics staff

All concerns and questions are tracked, managed and prioritized to ensure identification of dispositions and solutions. All calls and emails received by the third party vendor are prioritized to determine if immediate action is needed. Priority A calls require immediate action as defined by CDT-3001P-02, C&E Helpline Priority “A” Response Handling Procedure (**Attachment 19**).

D. Material Problem Reporting

In addition to the Helpline, PG&E maintains a material problem reporting (MPR) system that allows employees to report problems with any materials, tools, gas/electric/other equipment or infrastructure, and vehicles. Each MPR is logged in the appropriate database and reviewed by a subject matter expert to identify improvements.

E. Other Reporting and Feedback Channels

In addition to the channels described above, PG&E's workforce has the ability to raise safety concerns and issues through several other channels:

- Raising the issue or concern with their supervisors
- Raising the issue or concern to any Gas Operations leader
- Submitting the issue or concern confidentially directly to the Director of the Commission's Safety Enforcement Branch (contact information is on the Gas Operations intranet)

PG&E employees and contractors are continuously encouraged to communicate honestly and openly with supervisors and others in leadership positions and raise concerns, including those about safety, possible misconduct, and potential violations of laws, regulations, or internal requirements. All employees and contractors are empowered to stop work if a safety or quality concern arises and failure to do so could subject an employee or contractor to disciplinary actions or termination. Retaliation against an employee who raises a concern is expressly forbidden by PG&E's Code of Conduct, consistent with state and federal law. Employees in supervisory and other leadership positions may not retaliate, tolerate retaliation by others, or threaten retaliation.

IX. COMPLIANCE AND REPORTING

In compliance with various CPUC rulings, PG&E submits recurring compliance reports regularly to the CPUC. A listing of these reports is shown in **Attachment 20**.

PG&E also has a Self Reporting Process as required by ALJ-274 which requires gas operators to self-report to the CPUC non-compliances within 10 days of discovery and to implement actions to remedy those non-compliances. As part of this process, PG&E reaches out to employees at all levels of the organization encouraging them to help identify issues, gaps and non-compliance items. To date, numerous items have been raised and self-reported to the CPUC and in doing so allows PG&E to identify and make system wide improvements. Gas Operations encourages employees to look around, identify issues, and raise them so that actions can be taken to mitigate them locally and across the system.

In addition to Quality Control and Quality Assurance efforts as well as the CAP described previously, Gas Operations is leveraging the Self Reporting Process to identify gaps in current performance and then implement actions to remedy those gaps throughout the organization.

As of June 18, 2013, PG&E has submitted 55 self reports. This is the result of on-going communications to all employees about the need to report and the recognition of employees who raised the issues so that corrective actions could be taken. The encouragement of employees to speak up or raise their hand when they are aware of non-compliances is a direct result of a changing culture focused on safety and compliance.

X. METRICS AND GOALS

PG&E's 2013 goals include several measures based on the performance of Gas Operations and customer satisfaction:

- Safety Goals – 40% total weight based on public and employee safety; includes measures for 911 emergency response, leak repairs, gas emergency response, employee injuries and motor vehicle accidents
- Customer Goals – 30% total weight based on customer satisfaction; includes measures for survey results of customers and gas asset mapping.

Performance goals are a driving force behind management decisions and allocation of resources. In 2012, PG&E revised its performance goals and its rewards compensation (known as the Short-Term Incentive Plan – STIP) for employees. Safety is now the single largest factor in the performance goals representing 40 percent of the total. The remaining two factors - customer satisfaction and financial performance - are each weighted 30 percent. This change reinforces the importance of safety.

Attachment 21 shows some of the current key gas operating metrics that PG&E tracks.

XI. CONCLUSION

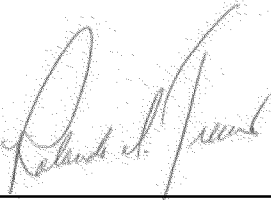
PG&E is committed to providing safe and reliable natural gas to our customers. Since 2011, PG&E has accomplished a lot of work and made significant progress toward our goal of becoming the safest, most reliable gas system in the nation. PG&E will continue to invest in our facilities, people, technology and operations in a manner that will complement previous investments and enhance the long-term safety and reliability of our system.




Nick Stavropoulos
Executive Vice President
Gas Operations



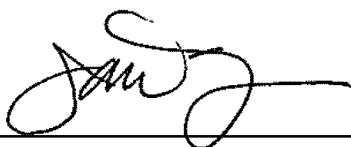
Jesus Soto
Sr. Vice President
Gas Transmission Operations



Roland Trevino
Vice President
Gas Operations Public Safety and Asset Integrity



Kirk Johnson
Vice President
Gas Transmission Maintenance and Construction



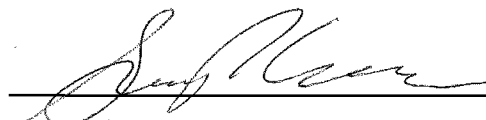
Jane Yura
Vice President
Gas Operations Standards and Policies



Mel Christopher
Sr. Director
Gas System Operations



Kevin Knapp
Vice President
Gas Distribution Maintenance




Sean Kolassa
Vice President
Gas Operations Investment Planning



Linda Limberg
Sr. Director
Safety



Frances Yee
Sr. Director
Gas Operations Regulatory Compliance and Support



Sumeet Singh
Sr. Director
Asset Knowledge Management