BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms.	Rulemaking 11-02-019 (Filed February 24, 2011)

PACIFIC GAS AND ELECTRIC COMPANY'S GAS SAFETY PLAN

WILLIAM V. MANHEIM
JONATHAN D. PENDLETON
Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2916
Facsimile: (415) 973-5520
E-Mail: J1PC@pge.com

Attorneys for:
PACIFIC GAS AND ELECTRIC COMPANY

Dated: June 29, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms.	R.11-02-019 (Filed February 24, 2011)

PACIFIC GAS AND ELECTRIC COMPANY'S
GAS SAFETY PLAN

Pursuant to Public Utilities Code Sections 961 and 963, and to the California Public Utilities Commission's (Commission) Decision Amending Scope of Rulemaking 11-02-019 and Adding Respondents (Decision 12-04-010), issued on April 20, 2012, Pacific Gas and Electric Company (PG&E) respectfully submits its Gas Safety Plan for review and acceptance by the Commission. A copy of PG&E's Gas Safety Plan follows, along with a cover letter from Nickolas Stavropoulos, PG&E's Executive Vice President, Gas Operations.

Respectfully Submitted,

WILLIAM V. MANHEIM
JONATHAN D. PENDLETON

By: /s/
JONATHAN D. PENDLETON

PACIFIC GAS AND ELECTRIC COMPANY
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2916
Facsimile: (415) 973-5520
E-Mail: J1PC@pge.com

Attorneys for:
PACIFIC GAS AND ELECTRIC COMPANY

Dated: June 29, 2012

Pacific Gas and
Electric Company®

Nickolas Stavropoulos
Executive Vice President
Gas Operations

77 Beale Street, Rm. 3231
San Francisco, CA 94105

Mailing Address:
Mail Code B32
P.O. Box 770000
San Francisco, CA 94177

415.973.2020
Internal: 223.2020
Fax: 415.973.6200

June 29, 2012

Before the Public Utilities Commission of the State of California
Rulemaking 11-02-019
(Pacific Gas and Electric Company ID U 39 G)

Re: Pacific Gas and Electric Company's Gas Safety Plan

Dear Executive Director Paul Clanon:

On behalf of Pacific Gas and Electric Company (PG&E), I am pleased to subit this Gas Safety Plan in accordance with Decision 12-04-010 to fulfill the requirement of Public Utilities Code§§ 961 and 963 to address Senate Bill 70S.

This plan provides a comprehensive overview of what we are doing to strive to make our natural gas pipelines the safest and most reliable in the country. PG&E's Gas Safety Plan highlights current and committed work and was heavily shaped by incorporating input and guidance from:

- All levels of PG&E's gas employees and contractors
- Experts from the Pipeline and Hazardous Materials Safety Administration, American Gas Association, Interstate Natural Gas Association of America, and CPUC staff
- External assessments, including reports and recommendations by the Independent Review Panel and the National Transportation Safety Board

PG&E's Gas Safety Plan assumes approval of our Pipeline Safety Enhancement Plan and our upcoming General Rate Case.

Our long-term goal of becoming the nation's safest gas utility is not some pie-in-the-sky dream. Since the tragic San Bruno accident in September 2010, we've made monumental progress in testing, validating and strengthening our pipeline system. Equally as important, though, is that we've begun to make the very necessary changes to strengthen the climate at PG&E of safety first, above all other priorities. We are steadfast in our commitment to achieve these goals for the people of California and for our industry as a whole.

We welcome the opportunity to discuss this Gas Safety Plan with you and CPUC staff.

Sincerely,

Nick Stavropoulos

Nick

Pacific Gas and
Electric Company®

Nickolas Stavropoulos
Executive Vice President
Gas Operations

77 Beale Street, Rm. 3231
San Francisco, CA 94105

Mailing Address:
Mail Code B32
P.O. Box 770000
San Francisco, CA 94177

415.973.2020
Internal: 223.2020
Fax: 415.973.6200

cc: Administrative Law Judge Meredith A. Bushey
Assigned Commissioner Michel P. Florio
President Michael R. Peevey
Commissioner Mark J. Ferron
Commissioner Catherine J.K. Sandoval
Commissioner Timothy A. Simon
Consumer Protection and Safety Division Director, General Jack Hagan
Service List R.11-02-019 (Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms)

Pacific Gas and Electric Company
Gas Safety Plan
Table of Contents

SB_GT&S_0883495

Pacific Gas and Electric Company
Gas Safety Plan
June 29, 2012

A. EXECUTIVE SUMMARY

The September 2010 San Bruno accident was tragic. It was also a catalyst for necessary change at Pacific Gas and Electric Company (PG&E) and in the natural gas industry in general. Across the nation and the state, it triggered new regulations and requirements to come into law. Within PG&E, it forced significant self-evaluation, benchmarking against industry leaders, and third-party review and assessment.

There has been a renewed vow across the company to a “safety first” culture that places public and employee safety above all other priorities. Simultaneously, there has been a movement at PG&E to concentrate on the basics of providing safe and reliable natural gas and electric service to 15 million northern and central Californians.

The submission of this Gas Safety Plan fulfills the requirement of Public Utilities (PU) Code §§ 961 and 963 to address Senate Bill (SB) 705. More importantly, though, PG&E’s plan highlights current and committed work, and connects the dots between all of PG&E’s efforts to ensure safe and reliable operations of its gas system.

PG&E’s Gas Safety Plan was heavily shaped by:

- A thorough review of external assessments, including reports by the Independent Review Panel (IRP), and the National Transportation Safety Board (NTSB);
- Input from regulators and industry associations, including the Pipeline and Hazardous Materials Safety Administration (PHMSA), CPUC senior staff, former NTSB leadership, American Gas Association (AGA), Interstate Natural Gas Association of America (INGAA) and others;
- A detailed assessment of industry best practices; and
- Critically-important employee feedback received from across PG&E

It addresses the safety of the gas system, the public, and employees. It also addresses the company’s culture, policies and procedures, risk management, employee and contractor training, commitment to compliance, asset management and maintenance, and use of records. The Gas Safety Plan references the extensive work proposed in PG&E’s Pipeline Safety Enhancement Plan (PSEP), and details improvements in emergency preparedness and response. Additionally, it delves into how PG&E measures the effectiveness of its safety systems against its goals.

All of PG&E’s safety actions are being implemented under a common framework provided by the British Standard Institutes’ Publicly Available Specification (PAS 55) for Asset Management, which is explained on pages 8-10.

The submission of this plan further supports PG&E’s commitment to implementing safety recommendations made by the NTSB (Attachment 1), PHMSA, the IRP and the CPUC.

PG&E's Gas Safety Plan assumes approval of PSEP. PG&E will include complementary distribution components of this plan in the 2014 General Rate Case Notice of Intent (NOI) to be filed July 2, 2012.

Since the San Bruno accident, PG&E has completed some critical work including:

- Validating the Maximum Allowable Operating Pressure (MAOP) of 2,088[1] miles of high consequence area (HCA) pipelines and 1,559 miles of non-HCA pipelines through May 2012
- Automating 37 valves through May 2012
- Conducting strength tests and verifying strength test pressure records for a total of approximately 262.5 miles of pipeline through May 2012
- Modifying the 911 notification process to respond to the NTSB's suggestion that SCADA (Supervisory Control and Data Acquisition) real-time operating data and alarms serve as triggers for 911 notifications
- Developing a comprehensive emergency response procedure for large-scale emergencies on transmission lines, which identifies a single person in charge, outlines specific protocols and provides for drills and training
- Incorporating performance measures and guidelines to assure continuous improvement in the public awareness program and
- Initiating a complete assessment of every aspect of the transmission integrity management program including threat identification and assessment

PG&E's long-term goal is to be the nation's safest gas utility. Realizing this vision in a sustainable manner will take time, but ultimately, it will ensure a safe, reliable gas system that PG&E's customers can count on. PG&E welcomes the opportunity to accelerate safety programs with the Commission's approval.

B. REGULATORY DESCRIPTI ON

The CPUC issued a resolution to implement PU Code §§ 961 and 963, which requires each gas utility to submit a plan to the CPUC for safe and reliable operation of its gas pipeline systems (transmission and distribution). As stated in SB705, 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. The operators' safety plans may reference existing components or include exhibits or attachments that cross-reference to other existing utility documentation, but should include a substantive summary of the referenced policy, procedure, or standard that is a component of the safety plan.

Gas operators are required to address 10 topics in the plan: (1) identify and minimize hazards and risks to protect the public and utility workforce; (2) identify safety-related systems to be deployed (including adequate documentation); (3) provide for adequate pipeline capacity and storage to reliably serve core and non-core customers consistent with CPUC tariffs and include

[1] Based on 1,805 miles of pipe segments in Class Location 3 and 4 HCAs in Class Locations 1 and 2 from the January 3, 2011 snapshot of Geographic Information System (GIS) database, and 283 miles associated with pipe segments that changed in class designation following the June 2011 class location study (from Class 1 or 2 to Class 3 or 4).

provisions for preventive/reactive maintenance; (4) provide for effective patrol and leak inspections; (5) provide for effective system controls to limit the damage from accidents; (6) provide timely response to customers and employee reports of leaks, hazards or emergency events; (7) include appropriate protocols for determining Maximum Allowable Operating Pressure (MAOP); (8) address risks of earthquakes or other major events; (9) meet or exceed minimum standards for design, operations or maintenance as prescribed by federal regulations; and (10) provide for an adequately sized and staffed workforce (utility and contracted) to carry out the plan.

Gas operators are also required to "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."[2]

PG&E's Gas Safety Plan provides a comprehensive articulation of the various components, e.g., policies, procedures, standards, and guidelines, which together make up the overall plan and also describes improvements that are being implemented or committed to for the future. Attachment 2 is a table showing how PG&E is addressing each element of PU Code §§ 961 and 963 for its gas transmission and distribution facilities within this plan.

C. BUILDING A SAFETY FIRST CULTURE

PG&E is building a culture of safety in large and small ways every day with the understanding that making these deep-rooted changes takes time. The company is encouraging its employees to feel 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 community.

PG&E examined and analyzed operations in 2011 and determined the company would have a much stronger safety culture if it had:

- A system-wide safety strategy
- A set of process safety management principles
- More visible and consistent safety messages from leaders
- More resources devoted to public and employee safety
- Increased adherence to and clear communication of all safety rules
- Increased emphasis on learning from safety incidents with less reliance on discipline to help eliminate a fear-based climate
- Improved data gathering systems
- Improved metrics to drive more appropriate behavior

This effort led management to make several improvements to the operational framework to promote safety-first.

First, the Board of Directors established the Nuclear, Operations, and Safety Committee, which is focused on public and employee safety for PG&E. The Committee's charter lays out the Committee's focus on safety (public and employee), compliance, and risk management policies

[2] Pub. Util. Code § 961(e)

and practices (including integrity management for Gas Operations). Senior leaders, particularly for Gas Operations, regularly engage the Board of Directors in discussions regarding safety.

The Chairman's Safety Review Committee, under the leadership of PG&E's Chief Executive Officer, has been established and 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.

In addition, PG&E has assigned a Senior Vice President to the new role of lead safety officer. This new position, together with executives representing each line of business (the Executive Safety Steering Committee (ESSC)) is responsible for establishing a common safety strategy and direction for the entire Corporation. Examples of this committee's actions include leadership for a grassroots safety program for employees, introduction of Process Safety Management principles and creation of a Safety First Climate.

PG&E has strengthened its core operational focus on safety, naming separate Executive Vice Presidents for Electric and Gas Operations. It has also hired technical experts to lead key operational activities as further described in the gas organization section below.

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 plain English which are readily understood, a rigorous quality assurance/quality control program, and a clear understanding of regulatory and industry requirements. Each of these elements is now the foundation of PG&E's Gas Operations organization.

1. Gas Organization

PG&E rebuilt the Gas Operations organization to clarify roles and responsibilities, provide effective governance, and establish a structure to improve key processes. This first key step, taken in 2011, separated Gas Operations from Electric Operations. The new Gas Operations organization was then structured around eight distinct functions and 22 key processes.

The eight functions with corresponding organization names 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, standards, that we follow (meeting and exceeding compliance requirements)
- Public Safety and Integrity Management - Reviewing the assets to assess their physical condition, identify degradation threats, and 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 efficiently and effectively (performing construction, maintenance activities)

- Distribution - Executing distribution work in the filed efficiently and effectively (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 22 primary processes identified for Gas Operations (Attachment 3) each have a process owner who is accountable for the process, functions as the "go to" person for issue resolution, provides follow-up, identifies and implements improvements. (Although there are many other processes within the operations, these 22 were identified as the initial key operational improvement areas in 2011.)

The second key change for the Gas Operations organization was to put in place, an appropriately sized, trained and technically skilled workforce. This required PG&E to identify resource needs, begin aggressive recruiting and hiring of trained professionals from throughout the industry to augment the existing workforce. Many of the key leadership positions within Gas Operations were filled by external candidates with extensive industry experience to improve overall performance.

PG&E's Gas Operations organization is forecast to grow by approximately 1,400 employees by the end of 2014. This will support the focus on safety and compliance through the successful execution of operating improvements and investment plans for both gas transmission and distribution assets.

2. Employee Engagement

PG&E is creating a strong line of sight between organizational objectives and the work performed on the gas asset system. Aligning corporate strategies and work plans supports a much more fluid bottoms-up flow of ideas and feedback to enable continuous improvement in the business, across a range of areas, such as where to target investment to further reduce risk, managing asset health, and updates to technical policy documents.

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

PG&E's executive leadership team of Gas Operations continuously visit various offices and field locations to speak with employees and get their thoughts on what we are doing well and where we need to improve. The company is also working hard to close the feedback loop by developing easy-to-use and centralized mechanisms to obtain employee feedback. Gas Operations is using this information to develop processes to ensure that meaningful employee input is incorporated into operations decisions.

D. EMPLOYEE AND CONTRACTOR FEEDBACK

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 employee focus groups participated in facilitated discussions; a total of six (6) focus groups were conducted. Approximately 190 Responses from these discussions were documented in a comprehensive "issues log" (Attachment 4a). In addition, a questionnaire was sent to selected Gas Operations contractors (Attachment 4b).

Among the issues raised, Union leaders made it clear that staffing levels, role clarification, and contracting are serious areas of concern for them. Over the coming months PG&E will continue to work with our labor leaders to address the issues raised.

Communicating to employees about these issues and their resolution is critical to employee engagement. PG&E will share the issues raised, the actions to address them, and monitor and track their resolution. Some issues may require more long term effort, and PG&E is committed to their resolution. PG&E will leverage existing Union committees (Attachment 5) to continue discussions in these areas and will use broader Gas Operations communications to continue to inform employees about the issues and their disposition.

PG&E will continue to use employee input and feedback to update this Gas Safety Plan. Demonstrating to all employees that the company values their ideas and input is critical for engagement. PG&E is currently developing improved systems to allow all employees to provide input, feedback and concerns at any time.

Additionally, PG&E's workforce currently has the ability to raise safety concerns and issues through several channels:

- Raising the issue or concern with their supervisors
- Raising the issue or concern to any Gas Operations leader
- Contacting the Compliance and Ethics Hotline (with the option of maintaining confidentiality)
- Submitting the issue or concern confidentially directly to the Director of the Commission's Consumer Protection and Safety Division (CPSD)

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.

When concerns are raised, employees in supervisory and other leadership positions are required to contact internal investigative resources when appropriate, and take appropriate action in response to investigation findings. 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.

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, PG&E maintains a material problem reporting (MPR) system where all employees are encouraged 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. Many improvements have been derived from this system.

PG&E has provided employees with the contact information for the Director of the Commission's Consumer Protection and Safety Division along with information on how to request confidentiality. This information is also provided on the Gas Operations Intranet site.

E. SAFETY APPROACH

The safety of the public and employees is PG&E's highest priority. PG&E has numerous programs, policies and procedures in place to identify and minimize hazards, risks, and dangerous conditions. The foundation of PG&E's Gas Transmission and Distribution Safety

Plan is built on: 1) developing a long-term, risk-based asset management plan (PAS 55), 2) implementing Process Safety, 3) developing and maintaining a risk register supported by risk algorithms and improved system data, and 4) the comprehensive revision of all standards and work procedures. PAS 55 provides a framework for managing PG&E's gas assets. Process Safety identifies and minimizes low frequency, high consequence events. Risk management focuses investments and operational changes based on impact and probability. Finally, standards, policies and work procedures establish the design, construction, and maintenance and operating procedures for safe gas operations.

1. 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.

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 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.[3]

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.

Beginning in 2011, PG&E has taken a number of aggressive actions to lay the foundation for achieving PAS 55 certification. PG&E's program will include: the Gas Operations asset base (physical plant and systems); the information needed to safeguard the assets; the people who work on the assets; the investment in the assets; and the intangible relationships associated with the assets. It also will address employees' and contractor skills, training and performance; standards and procedures; risk management; long term investment planning; and active employee feedback / input and continuous improvement.

The multi-year process to achieve certification will include a detailed review of safety, standards, procedures, training, quality controls, employee feedback and continuous improvement, and several independent audits during the process.

---

3 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.

PAS 55 requires the creation of a strong line of sight between the highest level organizational objectives at the Board of Directors to the activity 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 requires that information and records are well-maintained, legible, identifiable, and traceable. It requires the establishment of appropriate governance and controls to manage and maintain asset records and information. PG&E is focused on implementing asset management projects for both transmission and distribution to address these requirements and also improve accessibility and reliability of critical asset information.

PAS 55 audits whether training is being conducted by PG&E according to approved standards and technical policy documents. It also ensures that external contractors working on the PG&E system can demonstrate the right qualifications and understanding of standards and safe work procedures.

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 Lloyds Register, 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.

2. Process Safety

Process Safety is a comprehensive, risk-based approach to reduce the chance of low frequency, high consequence incidents from occurring. Although originally developed for the chemical and refinery industries, Process Safety has been demonstrated to provide 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 – for employees and the public.

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; there is agreement on all start-up requirements including training, drawings, spare parts and operating procedures before starting new equipment; and there are alternatives to address problems.

3. Risk Management Program

Risk management connects asset management planning and investments, and operational planning. It is PG&E's goal to support all gas asset investment decisions based on the quantifiable level of risk reduction -- so that the highest risk activities are prioritized before lower risk activities.

At the enterprise level, potential key risks identified by PG&E's Corporate Enterprise Risk Management include:

- Business Continuity and Disaster Recovery – Risks associated with disruption or failure of computer systems and other critical infrastructure.
- Cover-Up/Fraud - Deliberate misconduct or unintentional errors by employees or agents, which are concealed or deliberately not reported.
- Reliability - Failure to maintain reliable electric and gas service to large concentrations of customers or to interrupt a high profile event
- Qualified Workforce - Failure to manage the qualifications and training, succession planning, or recruitment/retention of the PG&E workforce results in an inability to perform essential functions
- Seismic – Seismic risk is one of the factors PG&E uses to prioritize pipeline replacement. PG&E has been replacing cast iron and steel pipe with modern plastic pipe that has better seismic performance.
- Emergency Response – Coordination activities, training and communication with city/county/local first responders within PG&E's service territory

PG&E has established a Gas Operations Risk and Compliance Committee to identify, assess, monitor, and mitigate risks. Chaired by Gas Operations executive vice president, the Committee's main objective is to actively manage risks and align risk management and mitigation activities with department goals, plans and resources and make risk management part of daily business operations within Gas Operations, including:

- The Gas Operations Risk and Compliance Committee identified three principal, overarching risks faced by Gas Operations: (1) loss of containment; (2) loss of supply and service; and (3) inadequate response and recovery.
- Loss of containment is the risk that gas will escape the system. PG&E's plan to mitigate this risk is driven by its operating risk assessment and integrity management programs (DIMP, TIMP, Damage Prevention, etc.) with focuses 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.
- The loss of supply and service is the 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.

- Finally, inadequate response and recovery is the 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.

4. Standards, Policies and Procedures

Gas Operations standards, work procedures and policies have been developed to ensure public and employee safety, and to meet or exceed regulatory requirements for design, construction, operations and maintenance and emergency response.

Currently existing Gas Transmission and Distribution Maintenance and Operations manuals/plans include:

- The Gas Distribution Maintenance Manual – TD 4380M Index (Attachment 6)
- Gas Distribution Operations Manual - TD 4381M Index (Attachment 7)
- The Gas Transmission Standards Manual Index (Attachment 8)
- Gas Emergency Response Plan Index (Attachments 9 and 10)

Four subject-based manuals have been published - Plastic, Corrosion Control, Gas Field Services, and Damage Prevention. Attachment 11 provides a list of additional subject matter manuals under development).

Over the next three years, PG&E plans to significantly update all standards and work procedures. PG&E has started a comprehensive process to improve safety and quality and incorporate best practices (including new technology, employee suggestions, training, and quality improvements). It is PG&E's intent to establish standards and work procedures which go well beyond minimum compliance.

5. Contractor Standards and Contractor Oversight

PG&E requires that its contractors complete safety plans and conduct all work to safeguard workers, and the public from injury. PG&E requires that all contract work be completed in compliance all with applicable federal, state, and local laws, rules, and regulations, for example the Occupational Safety and Health Standards, and the California Division of Occupational Safety and Health.

PG&E works collaboratively with contractors with the goal to ensure safe worker performance and that safety best practices are implemented and maintained during the performance of work.

PG&E provides its contractors with a Supplier Code of Conduct that contains principles and conduct standards, including safety conduct standards with which PG&E requires compliance by its contractors. For example, in compliance with DOT Operator Qualification (OQ) Guidelines listed in 49 CFR 192 and 195 and PG&E's Gas Operator Qualification Plan (Attachment 12), contractors and subcontractors who perform covered task work must be qualified to perform such work. Furthermore, contractors and subcontractors must be able to recognize and react appropriately to abnormal operating conditions that may indicate a dangerous situation or a condition exceeding design limits. PG&E has identified covered tasks/subtasks that are performed on its pipeline facilities (Attachment 13). UO Standard S4450 – Operator Qualification Program is included in Attachment 14.

Earlier this year, PG&E initiated a contractor safety scorecard process weighted 50/50 on job site safety and OSHA recordable injury rate. PG&E safety specialists have begun to evaluate transmission pipeline project sites where the contract value is more than $1 million, and station project sites where the contract value is more than $500,000 to assess site safety. The scorecard is finalized at the end of the project and rolled into a larger contractor evaluation process that also utilizes a scorecard.

As PG&E builds a library of scorecards, PG&E will be able to then use the safety scorecard as a component of the evaluation for future contractor work engagements. Once the scorecard process is fully established for transmission pipe and station assets, it will be rolled out to the remainder of the gas asset system.

Additionally, PG&E plans to audit outsourced work activities to demonstrate appropriate governance - outsourced processes and activities, knowledge and information required, and authorities and responsibilities of those managing the outsourced work must be documented. PG&E will be required demonstrate oversight of not only contractor performance, training and competence, but also the safety and compliance of their subcontractors. (e.g. PG&E will audit the drug testing laboratory used by contractors.)

6. 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 and experienced technical employees. PG&E conducted a comprehensive study in the fourth quarter of 2011 through the first quarter of 2012 to compare PG&E gas training to best-in-class,[4] and developed an extensive plan to elevate all PG&E gas training.

As part of this study, interviews with PG&E gas field personnel were conducted. Recommendations being implemented 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 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.

In parallel, improved training programs, curriculum and materials, and qualified instructors are being developed. PG&E has identified approximately 100 courses that will require development or significant expansion during 2012 to 2016. Improved and new courses in progress include training hydrostatic testing, In-line Inspection training, and construction work procedures.

7. 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.

---

4 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."

PG&E's OQ plan (Attachment 12) identifies required operating and maintenance tasks, provides guidance for achieving compliance with the requirements of 49 CFR Part 192 Subpart N, and establishes qualification methods for performing covered tasks on a gas pipeline facility. Covered tasks/subtasks are shown in Attachment 13.

Testing requirements include both written and work performance evaluations. The written test verifies 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 that must be qualified, and will be implementing improvements for tracking and reporting.

F. SYSTEM CONTROL

PG&E's Transmission and Distribution Gas Control monitors and controls the pipeline continuously, 24 hours a day, 365 days per year, to ensure that natural gas is safely received and delivered to customers. There are significant safety improvements being implemented to increase system monitoring and control, emergency response, clearance procedures and capacity planning which are discussed below.

1. Gas Transmission Control

The Gas Transmission Control Center monitors pressures, flows and system status at approximately 1,300 points, providing operational oversight of all compressor stations, storage fields, pipeline interconnections, and other key pipeline facilities. Gas Control operators can control system flows and pressures at approximately 800 points. In addition, Gas Control's SCADA system continually receives data from approximately 14,000 other points on the transmission system. The SCADA system utilizes alarms to warn Gas Control of changing conditions that could escalate to safety-related conditions unless corrective action is taken.

In December 2011, the system was updated to provide alarm prioritization to facilitate appropriate operator action upon alarm activation. This SCADA capability allows for alarm filtering based on priority, data type, and geographic location. Alarm priorities can now be configured based on four categories: Emergency, High, Medium, and Low. Additionally, in early 2012, PG&E implemented a geographical based operating process which allows for assignment of operator responsibilities based on "north" and "south" service territory assignments (Attachment 15).

Currently, PG&E is developing additional enhancements that will substantially expand the current SCADA visibility/control capability and implement/integrate technology tools to assist in predicting and proactively managing abnormal events on the transmission and distribution system. The three enhancements which are the foundation for building comprehensive controls framework to move to a predictive and proactive operational philosophy include:

- Automated Valve Program Implementation
- Distribution Control Center creation
- Data Historian integration with SCADA and Geographic Information System (GIS)

The three projects are the foundation of the broad initiative PG&E has undertaken to build a comprehensive controls framework implementing a control room strategy to move operational philosophy from monitoring and reactive to predictive and proactive. This will include:

- Additional SCADA monitoring points for pressures and flows to enhance understanding of pipeline dynamics.
- 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.
- Specific pipeline segment shutdown protocols to provide clear instructions on actions to be taken to quickly and effectively isolate a segment.
- Situational awareness tools, which utilize advanced composite alarming, and best practice alarm management methodology to highlight issues requiring immediate Gas Operator action.
- 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.
- Training simulation tools to prepare Gas Operators for potential pipeline rupture scenarios.

PG&E also plans to have an external party review PG&E's gas SCADA system and perform a best practices review of SCADA systems and their usage within other gas pipeline companies and related industries. This will include an evaluation of whether the installation of additional SCADA monitoring points above what is already proposed is warranted. PG&E will continue to assess the effectiveness of its SCADA and control systems, including the new tools and system modifications listed above and continuous improvements will be made to ensure that operators can make informed operating decisions.

2. Gas Distribution Control

PG&E's gas distribution system covers an area of 58,000 square miles, with 826 hydraulically independent systems. The distribution system is currently monitored using methods that require manual intervention in the field, causing a lag between data collection and response, and a lack of visibility into the real-time status of the system.

Some limited real-time distribution oversight is currently provided by Gas Control at approximately 275 continuously monitored distribution locations, (district regulator stations). In addition, some local distribution oversight is enabled by approximately 350 alarmed electronic monitoring devices which alert local on-call distribution supervisors if pressure set points are exceeded. Should an electronic monitoring alarm activate, the local distribution supervisor is responsible to assess the nature of the alarm and, if appropriate, have PG&E personnel dispatched to take action.

To monitor the balance of the distribution system, local offices now collectively deploy more than 500 permanent and temporary chart recorders[5] to record pressure data.

PG&E is creating a new Gas Distribution Control Center that will be operational before the end of 2012 and will create a predictive and proactive approach to system operations. This facility will be co-located with the existing Gas Transmission Control Center to

[5] 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.

facilitate communication and information sharing, and will be staffed with full time employees. The Distribution Control Center will begin to utilize existing SCADA capabilities and functionalities of the distribution system, primarily monitoring.

PG&E plans to install approximately 900 monitoring and control devices in 2012 and 2013 and 3,400 devices from 2014 through 2016, for a total of 4,300 devices.

Over time, the number of field monitoring locations will provide 95 percent visibility, 20 percent control of the distribution network, and 100 percent control of critical facilities. The planned deployment of the field installations is prioritized to address the areas of highest risk first.

To design the Distribution Control Center, PG&E benchmarked other companies in the gas transmission and distribution businesses and PG&E's plans represent the best practices employed by these companies.

By building the new Distribution Control Center, installing field SCADA equipment, and implementing new processes and control systems, and through the use of control room technology and tools, PG&E will effectively detect, prevent, and mitigate risks that have led to abnormal conditions and emergency events in the past.

3. Co-Located Transmission Control, Distribution Control and Dispatch Functions

By mid-2013, PG&E will locate transmission control center functions, distribution control center functions and gas dispatch functions into a single facility. The co-location of these three functions will enable the company to increase system knowledge and situational awareness to provide superior emergency response coordination.

The Control Centers are planned to have sufficient redundancy such that no single point of failure will affect operations. Key features of the 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" mirror-image backup facility in a different location such that control of the distribution system can be maintained in the event of a catastrophic failure at the primary Control Center (due to an earthquake, for example)

4. Operations Clearance Procedures

An important part of public safety is the Transmission Clearance Process for work that impacts gas flows, pressures, or gas quality. If a transmission pipeline is to be taken out of service for repairs, a plan and procedure ("clearance") must be formalized in writing and reviewed by the field personnel scheduled to perform the work. Transmission system clearances are managed and approved by Transmission Gas Control. PG&E's draft Transmission Clearance Procedure (to be issued in July 2012) is provided in Attachment 16 and includes the following controls:

- All sections and fields contained in the clearance form must be filled out completely to gain Gas Control approval.

- Individuals assigned the clearance supervisor role must have complete knowledge of the intended work and written clearance procedure before accepting this role.
- Field crew and control room operator must have clear and complete understanding of the scope and details of the clearance. The understanding of the clearance will be gained through a crew tailboard and phone calls to the control room.

For distribution, PG&E is in the process of developing the Distribution Clearance Procedure which helps eliminate work performance errors 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 gas Distribution Control Center for activities impacting the gas network. Field personnel will call the control room to report either a clearance or non-clearance activity.

Industry best practices are being adopted in the development of the distribution clearance process. These best practices will also be applied to the current gas transmission clearance process.

5. 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 excursions, and a corrective action and improvement plan which includes evaluating equipment set points and SCADA alarm policies. (An over pressure event is defined as a validated pressure increase of any amount above Maximum Allowable Operating Pressure for any length of time.)

PG&E's policy is to provide sufficient gas pipeline capacity, including under extremely cold conditions. 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 the 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 to enter 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 Utility Standard TD-5429S -Gas Transmission and Distribution Systems Capacity Planning Requirements (Attachment 17). The policy is supported by a companion document, TD-5429P-01 - Gas Transmission and Distribution Systems Capacity Planning Procedures (Attachment 18)

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 standards. PG&E's Gas System Planning Department 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 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 management.

As part of PG&E's proposed Pipeline Safety Enhancement Plan (PSEP), PG&E is analyzing 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. Pressure is a significant driver of pipeline capacity, so it is necessary to conduct hydraulic studies on each system to ensure that design day standards can be met at the reduced pressures.

G. PIPELINE SAFETY ENHANCEMENT PLAN (PSEP)

PG&E's PSEP Phase 1, which is currently before the CPUC, is PG&E's plan to enhance safety and improve operations by fundamentally changing the way PG&E manages its gas pipeline assets. Ultimately, PG&E will comprehensively assess all 5,786 miles of its natural gas transmission pipelines. The efforts included in PSEP are part of a broader coordinated Gas Operations strategy and are in addition to the improvements PG&E is making to its existing pipeline replacement and maintenance, risk mitigation and integrity management programs. PSEP Phase 1 covers 2011-2014, with Phase 2 commencing in 2015. There are four main components to PG&E's PSEP:

(1) **Pipeline Modernization** – PG&E will establish a known margin of safety on every gas transmission pipeline segment and verify pipeline integrity through strength testing, pipeline replacement, and pressure reductions, and will retrofit pipelines to accommodate the use of In-Line Inspection (ILI) tools.

(2) **Valve Automation** – PG&E will install 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. In addition, PG&E will upgrade 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.

(3) **Pipeline Records Integration** – PG&E proposes transitioning away from reliance on traditional paper records and moving to a fully integrated electronic asset management system. PG&E will consolidate its gas transmission pipeline data and records systems, collect and verify all pipeline strength tests and pipeline features data necessary to calculate the MAOP for all gas transmission pipelines and associated components, and implement a new fully electronic data management system that will facilitate enhancements in system operations, maintenance, inspections and compliance with new regulatory requirements.

(4) **Interim Safety Enhancement Measures** – To increase the safety of pipelines prior to testing or replacement, PG&E will validate the MAOP for all transmission pipeline segments in the system, has already reduced pressure on many pipelines (which will remain in effect until PSEP work on such pipe is completed), and has increased the

number of patrols and leak surveys. It will expand these interim safety enhancement measures under the implementation PSEP.

1. Pipeline Replacement

In 2011, PG&E also began implementation of its Transmission Pipeline Replacement Program which spans multiple years and is outlined in detail in PSEP. PG&E's Pipeline Replacement Program is a two-phase approach.

During Phase I, PG&E plans on replacing the following types of pipe:

- Pipe manufactured by processes generally thought to be susceptible to produce weld seam anomalies or weld seams with poor fracture toughness, including pre-1970, low-frequency Electric Resistant Weld (ERW), flash welded, Single Submerged Arc Weld (SSAW), furnace butt welded, lap welded, and hammer welded pipe.
- Pipelines constructed with welding techniques generally thought to produce low toughness or inferior designed girth welds, such as oxygen-acetylene welds, bell-bell chill ring welds, bell and spigot welds, and pre-1940 arc welds.

Under Phase 2 of PSEP, PG&E proposed to replace pipe segments with similar threats located outside urban areas. PG&E will utilize additional pipeline attribute data collected through the records integration effort to create appropriate project scopes and forecasts for Phase II pipeline replacement.

When transmission pipe is replaced, PG&E will design and upgrade pipeline segments to accommodate a future in-line inspection tool.

2. Strength Testing

In 2011, PG&E began implementation of its Hydrostatic Test Plan (Strength Testing) which spans multiple years and is outlined in detail in PSEP. PG&E's Hydrostatic Test Plan is a 2-phase approach for strength testing through 2014. Phase 1 addresses the following types of pipes:

- Pre-1970, low-frequency electric resistance weld (ERW), flash welded, single submerged arc weld (SSAW), furnace butt welded, and lap welded pipe operating between 20% and 30% Specified Minimum Yield Strength (SMYS) in urban areas.
- All urban-area pipes operating at or above 30% SMYS, unless it has been scheduled for replacement or an adequate strength test for the pipe exists.

  Phase 2 of the plan addresses the following pipeline:

- All urban area pipes operating below 30% Specified Minimum Yield Strength (SMYS), unless it has been scheduled to be replaced or an adequate strength test for the pipe exists.
- All identified pipe not previously strength tested or replaced in Phase 1, which includes pipe located in Class 1 non-HCA (rural areas), unless an adequate pressure test exists for the pipe.

PSEP progress reports are being provided to the CPUC every six months and will include updates on strength testing

3. Valve Automation Program

PG&E has embarked on an aggressive program of valve automation as detailed in PG&E's PSEP. The objective of the Valve Automation Program is to enable PG&E to either remotely, or with local automatic control, quickly shut off the flow of gas in response to a gas pipeline rupture. Under the design criteria for the program, automated 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 "piggability" 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 228 isolation valves. The Valve Automation Program "launch" commenced in 2011 with 20 new automated valve installations on the San Francisco Peninsula from Milpitas to San Francisco. At completion of Phase 1, the Valve Automation Program will result in approximately 410 miles of gas transmission pipeline in Class 3 and 4 areas being equipped with automated isolation valves, typically at 5-8 mile intervals, and automatic shut-off valves being installed on 9 pipe segments traversing 16 active earthquake fault crossings. Phase 2 will include the automation of roughly 330 additional valves.

The target of the Valve Automation Program is the retrofit of existing gas transmission pipelines. However, PG&E will also evaluate all new pipeline projects and replacement pipeline projects for valve automation based upon the decision-making criteria in this program, plus the following additional criteria: (1) all future projects will be evaluated for valve automation based upon anticipated future class location; and (2) pipe projects for existing Class 1 and 2 HCAs will automate manual valves required by these projects based upon the more inclusive Class 3 valve automation criteria.

All of the transmission valve automation field site installations result in new pressure and flow data being transmitted to the SCADA system increasing the visibility of pipeline conditions by PG&E's Control Room Operators. Upon completion of the Valve Automation Program, PG&E will have real-time knowledge of pipeline pressures at least every 5-8 miles on large diameter pipelines in Class 3 and 4 areas. Approximately 440 new pressure and flow transmitters will be connected to SCADA in the Phase 1 work.

PG&E has installed 100 new pressure transmitters across its system in the last year. The increased number of new field transmitters in Phase 1 will result in a 40 percent increase and at the end of Phase 2 will result in a 100 percent increase from PG&E's current number of pressure transmitters connected to SCADA. Each automated valve will be equipped with automatic and/or remote control capability designed to expedite the isolation of a section of pipeline. Each installation site will send various alarm conditions to the SCADA system.

4. MAOP Validation

In 2011, as part of PSEP and to ensure safe operation of PG&E's natural gas transmission lines, PG&E determined the MAOP in class 3 and 4 locations and class 1 and 2 HCAs that had no previously established MAOP determined through prior hydrostatic testing. In addition, records collection and MAOP validation was performed for all remaining pipelines located in HCAs in January 2012. 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. In total, validation was performed for more than 2,000 miles.

PG&E is continuing work to validate all remaining transmission lines in non-HCAs, which consists of more than 4,600 miles and is estimated to be completed by early 2013.

H. ASSET MANAGEMENT AND MAINTENANCE

PG&E's efforts to identify pipeline integrity threats and implement ways to mitigate risk include: Integrity Management (Transmission and Distribution); key transmission maintenance programs (PSEP including valve automation and records integration); key distribution maintenance programs (including plastic pipe initiative, leak survey improvements and records integration).

1. Transmission Programs

- **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 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 TIMP and approximately 20 percent of the gas transmission system is within an HCA and subject to the associated TIMP requirements. The remaining 80 percent, non-HCA pipeline segments continue to fall under PG&E's already existing Integrity Risk Management Program.

  PG&E's TIMP is addressed via various Risk Management Procedures (RMP-01 through RMP-13). Attachment 19 is a listing of the RMPs. PG&E, in collaboration with industry leaders in pipeline integrity management, is currently in the process of reviewing and revising the TIMP RMPs as well as drafting additional RMPs. RMP-06 (Attachment 20) specifically outlines the requirements of the TIMP including the calculation of risk, development of risk mitigation plans to continually reduce risk, and monitoring risk to accommodate changes in factors that affect risk.

  Three methods of integrity assessment are allowed: 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. While the majority of the system cannot currently accommodate ILI (smart pigging) device, efforts are underway to increase the number of segments in the system that are capable of being inspected by in line inspection devices in order to leverage the inspection technology advancements in this area.

- **In Line Inspections**

  ILI or pigging is a term used by the industry which describes a data gathering inspection tool that travels within an operating pipeline, accurately measuring the steel pipe wall thickness and internal geometry looking specifically for internal and external metal loss due to corrosion, gouges, manufacturing defects, and dents. When pipe segments are identified as having significant indications of integrity flaws, PG&E excavates the damaged section of pipeline and either repairs or replaces the pipe segment.

- **Strength Testing**

  Strength testing requires the pipeline to be removed from service and pressure tested with water or inert gas to verify its integrity. The pressure of the test and the duration of the test are determined by CFR 49 Part 192 and ASME B31.8S requirements. Pressure testing is being utilized to address the manufacturing threat on pipelines with possible unstable long seams as determined by

SB_GT&S_0883515

engineering evaluation based on manufacturing method and historical operating and test history.

- **Transmission Pipeline Replacement**

  PG&E's transmission pipeline replacement decisions are based on a variety of pipeline factors, including, pipe material and design, soil resistivity, pipe coating, pressure, potential for third-party damage, seismicity or the potential for ground movement, water crossings and number of customers served.

  (Refer to PSEP Pipeline Replacement for more information.)

- **Direct Assessment**

  Direct Assessment (DA) methods for external and internal corrosion are defined in federal pipeline regulations and follow a four-step structured process of: 1) pre-assessment incorporating physical, operational and maintenance data gathering, database integration, and analysis, 2) identification phase using either above ground tools or calculations to identify possible corrosion sites based on the evaluation or extrapolation from the database(s), 3) field examinations via excavation and direct assessment to confirm corrosion at the identified sites, and remediation as defined by regulation, and 4) post-assessment evaluation to determine if assessments are representative on a pipeline segment.

- **Pipeline Centerline Survey (GPS Quality)**

  PG&E's continued effort to ensure a safe and compliant pipeline system is the primary driver to perform a centerline survey of all of its transmission pipelines to gather GPS survey quality data (centimeter accuracy). This data, once collected, will be loaded and stored in PG&E's central Geographic Information System (GIS)[6] database. Accurate centerline data is a foundational need for all asset knowledge management and operations. Knowledge of the location of PG&E's pipelines is essential to the process of developing a plan for vegetation management and encroachments. Potential overgrown vegetation and encroachments can pose a safety risk to the public and create major impediments to proper maintenance of PG&E's facilities. These impediments can include significant challenges in performing leak surveys as well as any planned or emergency maintenance work on the pipeline. Furthermore, PG&E committed to obtaining GPS quality centerline data in a response to the Class Location OII.

- **Patrolling and Monitoring**

  All pipeline operators are required by 49 CFR, Part 192, 613 to have a procedure for continuing surveillance of its facilities to determine and to take appropriate action for safe operations and changes in class location. The surveillance of the pipeline facilities include pipeline patrolling as described in this plan, and in PG&E's Utility Procedure TD-4127P and TD-4127S (Attachment 21 and 22), and requires an annual class location review of gas transmission and gathering pipelines.

---

6 Geographical Information System (GIS) is a data system designed to capture, store, analyze, manage, and present all types of geographically referenced data. In the context of PG&E's gas pipeline system, its GIS contains transmission pipeline location information that can be displayed geographically, and contains corresponding pipeline data (e.g., pipe diameter, wall thickness, material strength/specification, strength test information, installation date, and other relevant data) which can be referenced from the geographic display.

When new construction is identified along a transmission pipeline, PG&E procedures require an evaluation of the class location. In addition, an annual system-wide class location reviews and supplements the existing continuing surveillance procedure and 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 in class location. The annual class location study is a second mechanism where PG&E identifies development along its pipelines in the event that its quarterly patrols fail for any reason to identify changes in class location.

PG&E is currently making improvements to the applicable standards and frequency requirements.

Consistent with 49 CFR, Part 192.611, if a class change is identified, the MAOP of the pipeline is reviewed and action is taken to assure the pipeline is commensurate with the class location. In addition 49 CFR, Part 192.609 requires the operator to immediately perform a study of the segments involved.

As part of the PSEP, PG&E proposed to increase patrols to bi-monthly for all Class 4, Class 3, Class 2 and Class 1 HCA pipe segments for which there are not complete pressure test records.

2. Distribution Programs

- **Distribution Integrity Management Program (DIMP)**

PG&E's Distribution Integrity Management Program (DIMP), based on the federal DIMP regulation[7], is designed to enhance safety by identifying and reducing pipeline risks and is foundational to PG&E's overall gas distribution system safety. PG&E is aggressively building its DIMP as part of a broader asset management effort, consistent with federal regulation and PAS 55.

PG&E's DIMP evaluates the risks to PG&E's gas distribution system and proposes mitigations to address those risks. Risks are identified through subject matter expertise of employees and industry experts, historical performance of the system as indicated by leak history, and the application of various threats to PG&E's pipeline assets using its risk algorithm. PG&E's DIMP risk algorithm is in its early stages and will develop over time as PG&E's technology and data sources improve. In the interim, PG&E will rely on leak history as a proxy for pipeline performance and will utilize leak history for determining prioritization of pipeline replacement work.

The DIMP applies to all gas distribution facilities and the program requirements are addressed within RMP-15 (Attachment 23).

The required elements of the DIMP regulation are specifically set forth in 49 CFR 192.1007, which states that "a written integrity management plan must contain written procedures for developing and implementing the following elements":

Knowledge
PG&E's Integrity Management uses available data sources (e.g., operating, mapping and pipe attribute data) to understand and manage system threats. A list

[7] 49 Code of Federal Regulation (CFR) 192, Subpart P, published on December 4, 2009 at 74 FR 63929.

of data sources currently utilized in PG&E's gas distribution risk algorithm is listed in Appendix A of PG&E's RMP-15 (Attachment 23).

To develop an understanding of the Company's distribution system, the Company utilizes leak repair and inspection forms (known as "A Forms"). Additional information is gathered on A Forms when repairs are made or when the pipeline is exposed during inspections or stand-by situations. The information collected about the condition of the pipeline, including pipe material, size, coating, depth of cover and other data are used to enhance or update existing data sources. This data currently resides in PG&E's leak management system, the Integrated Gas Information System (IGIS). PG&E is currently implementing the Gas Distribution Asset Management Project referred to as the Pathfinder Project, to improve and expand data access, and reduce the opportunities for data entry errors and misplaced or lost data. The Pathfinder Project is described later in this plan.

Identify Threats

PG&E's Threat Committees[8] 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.

The Company uses the information extracted from various data sources to populate a risk algorithm, which is applied to the Company's plat grid system in the current GIS or pipeline segments, as appropriate. The risk algorithm assesses all applicable threats and risks in the plat grid boundaries or pipeline segments. Collecting information on potential and existing threats (e.g., dig-ins, cross bores, etc.) is the responsibility of the core and support Distribution Integrity Management staff and is completed on a continuing basis.

Threats with similar attributes or causes are grouped into primary threat categories (corrosion; natural forces; excavation damage; other outside force damage; material, weld or joint failure; equipment failure; incorrect operation; other concerns) based upon the requirements listed in 49 CFR 192.1007(b). Where more practical, the Company further refined the threat categories identified in 49 CFR 192.1007 into more descriptive primary and secondary threat categories. This additional categorization is performed to assist in analyzing the differing threat mechanisms and to facilitate measurement of the effectiveness of future additional measures implemented to reduce risk.

Evaluate and Rank Risk

Potential and existing threats to the distribution system are evaluated as part of a comprehensive risk assessment process for the Company's distribution facilities. The procedure used for the assessment and validation of this risk assessment process is documented in RMI-G - DIMP Probabilistic Validation Process (Attachment 24). In parallel to using the risk algorithm, PG&E is utilizing the leak information to map historical leak locations (clusters are defined as two leaks within a 100-foot section of pipe) along with existing open leaks. The clusters are then used in a performance based analysis to identify areas of pipe that have a higher historic leak rate for mitigation

---

[8] 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 should have at least two years' experience in the area of expertise of their committee.

Through this process, the Company determines the relative importance of each threat and establishes a ranking of the risks to distribution pipeline and associated facilities. Contiguous pipe segments and associated appurtenances that operate at 60 pounds per square inch gauge or less are being evaluated using a probabilistic risk assessment methodology. The risk data is generated on a plat sheet basis, which groups contiguous segments of pipe and pipe facilities together.

Identify and Implement Measures to Address Risks

Once methods for managing and mitigating risks are identified, System Integrity Process Owners (there are currently seven: 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. If the overall approach to mitigation is deemed ineffective, the Threat Committees will be responsible for reevaluating the risk and its root cause to determine a more effective approach.

Following PG&E's initiation of its DIMP in August 2011, the most significant threats identified by the risk algorithm and Threat Committees were considered for mitigation. These threats included 3rd party damage, over-pressurization events, cross-bored sewers, low pressure systems, and corrosion, among others. Based on the input and analysis of the Distribution Integrity Management team and Threat Committees, PG&E established a comprehensive list of mitigation measures to reduce these risks which are documented in Attachment A to PG&E's RMP-15 (Attachment 23).

Measure Performance, Monitor Results, and Evaluate Effectiveness

System Integrity Process Owners, described above, are responsible for monitoring the impact of the Risk Management (RM) initiatives to determine their effectiveness in minimizing risk to the Public, Customers, and the Company.

The Company has a list of current performance measures, along with the baseline measurement for each performance measure. The baseline is usually a measurement either prior to implementing the actions to lower risk, or an initial measurement when the actions have already begun. It is intended that baseline measurements be foundational, historic, and static.

Periodic Evaluation and Improvement

As stated above, System Integrity Process Owners are responsible for monitoring the impact of the RM initiatives. If the overall approach to mitigation is deemed ineffective, the Threat Committees will be responsible for reevaluating the risk and its root cause to determine a more effective approach.

In addition to performance monitoring, the Company's program evaluation consists of four parts:

- **Threats and Risk Review**
  On an annual basis, the Threat Committees, with the assistance of RM and System Integrity (SI) teams, will review the contributions to probability or likelihood of failure from the various threat components.
- **Quality Assurance Audits**
  At least one Quality Assurance (QA) audit will be completed each year. At a minimum, a QA audit will be performed on the following programs:

Corrosion Control, Damage Prevention, Leak Management, Regulation Maintenance and Valve Maintenance.

- **Integrity Management Plan Re-Evaluation**
  The SI and RM teams complete the reevaluation at least every five years and make necessary changes to the plan. The results are used to revise RMP-15.
- **External Regulatory Audits**
  The external audit (completed periodically when requested by Regulatory agencies) will examine PG&E's Distribution Integrity Management Program performance against regulatory requirements. This audit will measure how the Company's Integrity Management and activities are progressing in relation to the regulation. PG&E is scheduled to have a CPUC audit of its Integrity Management Program in December 2012.

Report Results

In the annual report to the Office of Pipeline Safety and the CPUC, as required by 49 CFR Section 191.11, the Company reports at least six required performance measures: compression fitting failures; number of excess flow valve installations; number of hazardous leaks; number of excavation damages; number of underground service alert tickets and total number of leaks. PG&E's first report was filed in March 2012 (Attachment 25).

Because of the significant diversity among gas distribution system operators and systems (e.g., miles of line, types of pipe installed, location, etc.), the DIMP requirements are high-level and performance-based and do not prescribe specific methods of implementation. To comply with the rule, PG&E utilizes a DIMP risk algorithm to allocate resources based on risk. The risk algorithm is updated on a regular basis.

- **Distribution Pipeline Replacement**

PG&E's Gas Pipeline Replacement Program (GPRP) was established in 1985.[9] The scope of the program initially consisted solely of cast iron pipes and all pre-1931 steel main. Over time, the program scope has been modified, and now targets pre-1940 gas main of significant risk. The primary goals of the GPRP are to reduce leaks due to normal stresses and corrosion and to reduce the risk of weld, pipe, or joint failure due to seismic stresses.

PG&E uses age, materials, seismic factors, and gas leaks to identify and prioritize gas main for replacement. In addition to gas main replacement, the program covers related service replacement and meter relocation work.

Through the end of 2011, the GPRP replaced approximately 2,161 miles of distribution main and 179,700 services. At the end of 2012, 48 miles of cast iron main and 149 miles of steel main will remain in the GPRP program. Of the 550 miles of GPRP distribution pipe in locations with relatively high seismic risk, PG&E has replaced 509 miles, with 41 miles remaining to be replaced.

PG&E prioritizes all GPRP projects based on a risk determination that includes the probability of a leak on each section of pipe and the potential consequences of that

[9] The Company submits annual status reports on the GPRP to the Commission in accordance with Decision 86-12-095, 23 CPUC 149, 199. The most recent report was submitted in April 2012.

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. Throughout the duration of the GPRP, the Company has focused on addressing the highest priority pipe first.

PG&E's distribution pipeline replacement decisions also consider many factors, including seismic activity. In 1987, PG&E, in conjunction with Bechtel, developed a method for prioritizing GPRP pipe segments with the purpose of identifying the pipeline segments posing the greatest risk. Pipe segments are identified for replacement based on relative priority, known as the "Priority Value." The priority value calculation includes factors for:

- Pipe age
- Leak history
- Cathodic protection (passive and active)
- Seismic susceptibility
- Structure and population proximity

The calculated priority values range from 0 to 100 with higher values representing pipe posing the greatest risk.

Going forward, rather than maintaining separate programs for different types of distribution pipe, PG&E is developing a longer-term investment strategy for the entire pipeline system to better ensure system integrity and the safety of PG&E's customers. PG&E's pipeline replacement program will be based on the combined work of PG&E's Investment Planning and Distribution Integrity Management Teams. Distribution Integrity Management identifies the pipe to be replaced based on performance and leak history or other risk factors. Investment Planning will determine the number of miles of pipe PG&E needs to replace per year to maintain long-term system integrity and will take the lead to develop a cost-effective replacement strategy.

Certain pipe materials are performing worse than others in that they have high leakage rates compared to the system wide average. For pre-1940 steel pipe, to bring the leak rate down to the system average, PG&E needs to replace 60 miles annually for 15 years. This will replace 900 miles of the total 1,910 mile population of pre-1940 steel pipe within this time period. For Aldyl-A pipe, PG&E needs to replace 100 miles per year for 15 years to decrease the leak rate to the system average. This would replace 1,500 miles of the approximately 5,735 miles of Aldyl-A pipe within this time period.

PG&E's long-term plan is to constantly re-evaluate the leak rate trend and other risk factors to ensure the right number of miles will be replaced to decrease leak rates to the system wide average and to otherwise reduce risk. PG&E expects to replace the population of pipe materials above due to the current performance of these pipe materials. However, if the risk of other pipe materials proves to be higher, the population of pipe with the highest risk will be replaced. The plan for 2014 through 2016 is to replace 60 miles of cast iron and pre-1940 steel pipe, and replace 100 miles of plastic pipe annually. This will likely be Aldyl-A pipe; however, if non-Aldyl-A plastic is identified as riskier than the remaining Aldyl-A plastic, it will be replaced first.

- **High Pressure Regulators Inspections and Maintenance**

  High Pressure Regulators (HPR) are also commonly referred to "farm taps". PG&E has an aggressive plan to address HPR Replacement work as a result of new findings during an accelerated gas transmission leak survey. A significant number of leaks are associated with small diameter (i.e., usually ¾ inch) regulator sets served off of a transmission pipeline (PG&E refers to these installations as an HPR set). Over time, many of the components associated with service lines deteriorate, including valves and HPR sets for one or two customers.

  All farm tap regulator sets were first inspected for atmospheric corrosion on a system-wide basis beginning in 2010 and concluding in 2011. These inspections were required to demonstrate compliance with 49 CFR§192.479, "Atmospheric Corrosion Control: General" and 49 CFR§192.481, "Atmospheric Corrosion Control: Monitoring." They were completed per Bulletin TD-H-10B-001 (Attachment 26).

  PG&E is in the process of developing a procedure that will address maintenance inspections for all farm tap regulator sets. The purpose of the new proposed work procedure is to satisfy the ongoing regulatory requirement for a 3-year atmospheric corrosion inspection as well as adding additional Company required maintenance to better ensure the safety and reliability of gas service to customers. Past Company standards have required maintenance of farm tap regulator sets for cause only. The proposed work procedure adds a 3-year set point and lock-up check to farm tap type regulator sets to coincide with the code required inspections for atmospheric corrosion.

- **Cross-Bored Sewer Project**

  Since operators of sewer facilities are not required to locate and mark their facilities, the installation of gas services or main pipe via boring construction methods can result in a sewer line being "cross-bored" (the sewer line is penetrated or otherwise cut open by the subsurface boring operation, and a gas line installed crossing through the sewer line or immediately adjacent to the open section of sewer line). Cross-bored sewers are found on many gas distribution systems throughout the U.S. Cross-bored sewers represent a safety concern due to the potential accumulation and ignition of natural gas that migrates through the sewers and into homes or buildings.

  The Cross-Bored Sewer Project developed in 2011, inspects and remediates cross-bored facilities created by various methods of installing gas mains and services.

  As part of the Cross-Bore Sewer Project, PG&E has implemented a new procedure (Attachments 27a and 27b) to inspect for potential damage to underground facilities that are not part of the one-call list program (e.g., sewers, storm drains, private party underground facilities, etc.). This new procedure utilizes video equipment to inspect any dry bored hole before installing new mains or services into that bored hole.

  Another part of the Cross-Bore Sewer Project is the identification of potential historical cross bored sites. Once PG&E determines that a service line could potentially be a cross bore, PG&E contracts with a sewer inspection company to inspect both the sewer main and sewer lateral to verify that the sewer system does or does not have a gas line in it. Appropriate action is taken if a gas line is identified. This program is expected to continue over the next 9 to10 years. During this time frame, approximately 500,000 services will be reviewed and/or inspected at approximately 20,000 to 50,000 sewer laterals per year. The scope identified for the project includes all GLRP projects where Horizontal Directional Drilling (HDD) was the installation method, and all services replaced under the Copper Service Replacement Project (CSRP).

- **Copper Service Replacement**

  In 2007, PG&E established a new Copper Service Replacement Program (CSRP) which includes the replacement of approximately 42,000 copper services. PG&E plans to replace all known copper service by the end of 2013 other than approximately 500 copper services that will be replaced as soon as practical after 2013 due to street moratoria. The street moratoria, which are generally in place for five years, hinder PG&E from performing work on streets that have recently been replaced and restored.

- **Aldyl- A**

  PG&E has approximately 5,665 miles of Aldyl-A plastic pipe in service in its distribution system. PG&E has performed analysis of various types of Aldyl-A pipe used in the system and is building a searchable Aldyl-A GIS system of Aldyl-A locations and properties. Additionally, PG&E is updating the risks associated with Aldyl-A in the risk algorithm.

  Other Aldyl A safety improvements include:

  - Riser Identification Project to address specific types of Aldyl-A risers with higher than normal leakage rates;
  - Identified 23 miles of Aldyl A pipe for replacement in 2012;
  - Updated the GIS system with Aldyl A pipelines; working to build additional pipeline and service attribute information in GIS;
  - Working with an industry third-party expert to update and implement a risk algorithm that identifies Aldyl A to increase the company's ability to identify, evaluate, and rank threats;
  - Implemented the first iteration of the risk algorithm and is working to complete the second version.

- **Plastic Tee Cap Repair Program**

  PG&E's main method of risk mitigation for pipe with multiple leaks is to replace the pipeline. As PG&E has researched the leaks associated with Aldyl-A pipe, it has become apparent that the primary source of leaks is plastic tee caps. Tee cap leaks are not an indication of the overall health of the pipeline, but rather indicate an issue with the material used in the tee and associated cap and the stress applied during the installation process. As a result, the issue is frequently consistent within an area (installed on the same job) and can be resolved through repairing the tee caps on the pipeline.

  The plastic tee cap repair program identifies areas where clusters of plastic tee cap failures and repairs the remaining tee caps using keyhole technology to minimize paving costs and time. In addition, PG&E is also testing techniques to do an evaluation of the integrity of the adjacent pipe to ensure that plastic tee cap repairs are the only work required to ensure pipeline integrity of a specific plastic system.

- **Meter Protection**

  PG&E's meter protection program addresses gas meter locations that do not conform to current Company standards or federal pipeline safety regulations. The program focuses on two types of non-conforming meter locations: Inadequate protection from damage by vehicles, and inaccessible service or shutoff valves.

  PG&E is in the process of completing this multi-year effort ahead of schedule.

- **Low Pressure Vault De-Watering**

  PG&E identified several efforts to mitigate the risk associated with low pressure system. This mitigation effort is related to water intrusion into the back side of the pilot on the regulator, potentially causing the pressure set point on the regulator to change.

  In 2012, PG&E initiated a pilot effort to identify low pressure regulator vaults susceptible to flooding and establish a contract with a vault pumping vendor to remove water from the vaults twice during the wet season. This effort should reduce the amount of water accumulating in the vaults and reduce the risk of water intrusion into the pilot equipment. In complement to this program, PG&E is also undertaking an effort to raise all vent lines for low pressure regulators to reduce the probability of water intrusion. Additionally, PG&E plans to raise the height of low elevation drains and thereby reduce the potential for over pressurization events starting in 2012.

- **Main Replacement for Low Pressure to High Pressure**

  Low pressure systems are primarily located in the older portions of high population density urban cities like San Francisco, Oakland, Stockton, Sacramento, and Fresno.

  There are approximately 700 miles of low pressure main that operates at 10 inches of water column that has been identified for replacement to reduce the amount of low pressure main in order to:

  - Increase level of safety for the public due to the installation of service regulators and Excess Flow Valves at each service.
  - Increase operating flexibility and service delivery abilities.
  - Limit exposures to system compliance and pressure issues.
  - Limit exposures due to system outages caused by equipment failures and water intrusion.

- **Atmospheric Corrosion**

  Atmospheric Corrosion (AC) inspections for all exposed gas distribution facilities except for customer meter sets is performed every five years as part of leak survey and includes a visual inspection for AC on both the above ground pipe and meter set to confirm the condition of the pipe surface, and to identify any necessary repairs such as cleaning, painting or recoating. AC inspections for other gas distribution assets are inspected through other maintenance activities. For example, regulator stations are inspected for AC during regulator station maintenance.

PG&E is planning to create dedicated painting crews responsible for painting all above ground gas distribution assets. Historically above ground gas distribution assets were painted by the gas distribution preventative maintenance crews described above. Given the large number of preventive maintenance activities required, painting was being performed when all other preventive maintenance activities were completed (for example, planned painting every other Friday afternoon) resulting in a de-prioritization compared to other preventative maintenance activities. The planned painting activities will prevent corrosion by preventing water from coming in contact with the surface of the pipe.

- **Isolated Services**

Results from performing cathodic protection resurveys indicate that some buried steel risers are "isolated" from the cathodic protection system as a result of past reconstruction projects. For example, a steel service may have been replaced with plastic pipe between the steel main and steel riser. The steel main continues to be cathodically protected but the steel riser may be isolated meaning that it is not being cathodically protected and would be more susceptible to corrosion, which could lead to leakage. To address this concern, the Cathodic Protection Isolated Services Project was developed in 2002 to identify these locations and to systematically verify cathodic protection levels on these services. Each isolated service found with inadequate cathodic protection needs to be addressed; some simply by immediately installing a drivable anode in dirt while others require a separate crew to first drill through concrete before installing the drivable anode. A drivable anode is a small galvanic anode with a wired clamp that is installed by using a hammer to drive the anode into the dirt and attaching the clamp to the steel riser.

PG&E provides quarterly reports to the CPUC on the progress achieved for checking and addressing isolated steel services (Attachment 28).

PG&E expects to complete the Isolated Steel Service Program by the end of 2012.

- **Valves – Emergency Shutdown Zones**

Emergency shutdown zone valves are used to isolate portions of the gas distribution system during an emergency. PG&E's current standard (Attachment 29) requires shutdown zones to not exceed 40,000 services or 500 services in locations with buildings that are predominantly four stories or higher.

PG&E plans to adopt a lower services count consistent with best practices in the gas industry. This will require the installation of an additional 3,165 valves in order to reduce the service counts per shutdown zone. Installation of these additional valves will reduce emergency response times; reduce the number of customers impacted during a major event and increase operational flexibility during a major emergency event.

3. Additional Key Maintenance Programs

- **Leak Survey**

Leak surveys are conducted at regular intervals throughout the gas transmission and distribution systems. The Company's policy is to search for, evaluate, and control gas leakage in the interests of safety and efficiency of operation. Utility standard S4110 (Attachment 30) outlines PG&E's requirements for leak surveys and summarizes the various standards and guidelines for leak survey work.

Surveyors perform field work for transmission pipelines and adjacent distribution facilities separately. Separating the surveys makes it easier to use specialized tools, such as the optical methane detector (OMD), that optimize efficiency.

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 schedules (every 6 months, annually, or every 5 years).

As part of the PSEP, PG&E proposed to increase leak surveys to six times per year for all Class 4, Class 3, Class 2 and Class 1 HCA pipe segments for which there are not complete pressure test records.

Pipeline safety regulations require PG&E to conduct periodic or routine leak surveys on its distribution 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.

PG&E's current leak survey cycles are as follows:

Six months:
- Substations

Annual:
- Business districts;
- High public assemblies (e.g., schools);
- Atmospheric exposed mains;
- Bare steel mains.

Three-year:
- Copper services;
- Cast iron mains;
- Unprotected steel mains.

Five-year:
- All others

Approximately 94 percent of the distribution system is currently surveyed on a 5-year cycle.

PG&E will be implementing several leak survey initiatives which will result in more leaks being identified. These initiatives include:

- Using the Picarro Surveyor in one division in 2013, 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
- Accelerating the rate of rechecking Grade 3 leaks.

Benchmarking shows that surveying residential neighborhoods at least every three years is an industry best practice and will mean that PG&E will find leaks more frequently, allowing PG&E to repair leaks more frequently.

PG&E is acquiring new technology to more efficiently conduct its leak surveys. Multiple Leak Survey Detecting Equipment and Survey Grading Equipment are being 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 communicate 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 leak, leading to a more accurate survey and associated grading of 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 a 1,000 times more sensitive than incumbent leak survey/detection equipment, uses cavity ring down spectroscopy, distinguishes between natural occurring gases to that of natural gas, and otherwise has the possibility to not only increase the efficiency of leak survey, but 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.

- **Leak Repair**

Pipeline safety regulations require gas operators to repair hazardous leaks promptly.[10] The Company prioritizes the severity of identified leaks and requires immediate response to all hazardous leaks. Grade 2 and Grade 3 leaks are periodically rechecked to determine whether repair should be performed earlier or on regularly scheduled repair date. Some classes of non-hazardous leaks are repaired within three months; others are repaired within 15 months; others are only scheduled for recheck. Attachments 31a and 31b include the Leak Repair procedures.

All 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 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.

10 49 C.F.R. §192.615.

- **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 they become hazardous).[11]

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 of all activities required to render gas leak repaired and safe.

All PG&E employees and contractors who perform leak surveys are trained and tested in the consistent application of PG&E's policies regarding the grading and repair of leaks. All leak surveyors must pass the test and receive their Operator Qualification before they are allowed to perform leak survey.

PG&E will be implementing several leak survey initiatives as mentioned in the Leak Survey section above which will result in more leaks being identified. To address this increase, PG&E has begun to repair Grade 2 leaks within 15 months rather than within 18 months. Additionally, rather than rechecking above-ground Grade 3 leaks every 15 months, PG&E plans to repair them within 15 months. This will promote both efficiency and safety by limiting the number of visits to the leak site and by repairing the leaks before they have an opportunity to become hazardous.[12]

The Company is also developing an end-to-end paperless, automated process from leak find to leak repair. This automated system is part of the Pathfinder Project.

- **Damage Prevention**

Pursuant to Code of Federal Regulations 49, Section 192.614, PG&E is required to have a Damage Prevention Program. Damage Prevention is an end-to-end process which 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.

The Damage Prevention processes in place were primarily established by PG&E's damage prevention technical team and are reviewed annually. Key metrics have

---

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

12 The cost of repairing the above-ground Grade 3 leaks is offset by the cost of not having to continually resurvey them

been established and are monitored monthly. The program is currently undergoing data quality cleanup efforts and simultaneous process alterations in an effort to improve the overall end-to-end process.

Damage Prevention consists of four main processes working together to help prevent damages from third party excavation activities as described below:

1. **Public Awareness**

   Public Awareness 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 magazines and papers, conducting companywide campaigns for Call 811 Before You Dig and attending USA S.A.F.E. events involving educating excavator companies of safe digging practices and recommendations. The Public Awareness program recently underwent a rigorous three day audit by the CPUC at the end of which PG&E received zero violations.

   An important element of the program is the development of key performance metrics. Primary among those metrics is a measure of the program's effectiveness. PG&E is working with communication experts and benchmarking throughout the industry to develop measures of program effectiveness.

2. **Locate and Mark**

   Federal pipeline safety regulations[13] and state law[14] 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 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).

   By identifying underground facilities before an excavation can take place, the potential for damage to underground infrastructure is limited. In the first half of 2012 the PG&E Locate and Mark program purchased many new tools to help locating personnel be more accurate and efficient with their locating efforts. Also, several pilots are underway to identify new tools that will allow locators to more effectively locate facilities that are currently difficult or impossible to locate. The introduction of these tools and associated training will help prevent possible damages by third party excavators who follow current California Excavation Laws when performing their excavations.

[13] 49 C.F.R. §192.614.

[14] Gov. Code §4216.

3. **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. In addition to internal processes, the Dig-In group has been working with Governmental Relations and Industry groups to drive legislation regarding fines for repeat offenders of the one call law.

4. **Pipeline Patrol**

   Pipeline Patrol consists of patrolling transmission pipelines to ensure they are protected and no unauthorized excavations are taking place nearby. 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, exceeding the federally mandated patrol standards[15]. 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 also be requested after natural disasters or major incidents to confirm the conditions of PG&E assets.

   See also Patrolling and Monitoring, above.

5. **Pipeline Markers**

   Pipeline markers are used to indicate the approximate location of the respective pipeline along its route. The markers are signs on the surface above natural gas pipelines and 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.

   PG&E will leverage the Pipeline Centerline Survey effort, described in Section G (Asset Management and Maintenance – Transmission Programs), to install or rectify pipeline markers along the pipeline centerline and its respective right-of-way. Pipeline right-of-ways that are well marked indicate the presence of underground pipelines to the public and can help prevent damage from digging, one of the most common causes of pipeline accidents.

- **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 cause leaks and catastrophic pipe failures. Leaks caused by corrosion decrease system reliability, increase maintenance, shorten the useful service life of pipe and create public

[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.

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. The average time a CPA system is not within the required tolerances is 30 days prior to PG&E's knowledge.

PG&E began installing devices to allow remote monitoring of the cathodic protection systems which allow continuous visibility of the CPA where these devices are installed. 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.

- **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 in GIS and that information is used to identify if there is a "potential for ground movement". This data is updated annually to ensure up to date information is incorporated. Risk mitigation for transmission pipelines may include reroutes, installation of isolation valves, automated or remote control valves.

I. DOCUMENTS AND RECORDS

PG&E has adopted the NTSB recommendation for records that are traceable, verifiable and complete. PG&E requires that all records are well-maintained, legible, identifiable, and traceable. Further, information should be controlled, the right people have access to what they need to perform their work, and that information provided in multiple systems is consistent from system to system.

PG&E is focused on implementation of asset management projects for both transmission and distribution. 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.

1. Gas Transmission Asset Management Project (GTAM or Mariner Project)

The Mariner Project was proposed as part of PSEP and focuses on transmission information and records and 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 (e.g., Materials Traceability enhancements); and
- PG&E's ability to assess and mitigate potential public safety risks.

The system consists of five key components:

1) Develop business requirements for the new systems and processes;
2) Collect, digitize, validate, and migrate pipeline data into integrated electronic information management systems, SAP and GIS
3) Upgrade the existing GIS system to track component-level information;
4) Upgrade the interfaces among information management systems; and
5) Develop and implement mobile technology

2. Gas Distribution Asset Management Project (Pathfinder Project)

The Pathfinder Project will enhance and convert PG&E's gas distribution asset data into an integrated GIS/SAP system and 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 of and accessibility to 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 will enable 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 –** accurate and complete gas distribution geospatial connectivity model and data set to feed and enable commercial integrity management solution for distribution integrity management programs
- **Improved System Planning –** provide system planners and engineers with a single source of complete and accurate data about the underlying assets pertaining to the gas distribution system

3. Documentum

Documentum will be utilized as the single source for all electronic documentation to support compliance and regulatory reporting for Gas Operations. Documentum will deliver an enterprise-wide foundation for the management of digital content and will include electronic documents, electronic records and digital media that is unstructured in nature (unstructured content is that which is not stored as part of another enterprise application, such as SAP). As the system of record, new technologies will be required to address all of the documents that support the pipeline. This effort is intended to address optical character recognition capabilities, full-content searching of the documents, advanced reporting, integration with existing PG&E tools, advanced search and retrieval, storage and growth, and disaster recovery. The project will also undertake the conversion of non-electronic format such as paper to an electronic format. Documentum will adopt standard taxonomy and will be utilized to implement record retention best practices, including standards, policies and controls.

J. SAFETY AWARENESS AND PREPAREDNESS FOR CUSTOMERS AND FIRST RESPONDERS

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. PG&E efforts in this area focus on ensuring appropriate public awareness as well as working closely with first responders to provide training, information and tools.

1. Public Awareness

PG&E has made improvements to safety resources available to first responders and the general public. PG&E's public website for safety is now more easily accessible and includes tips and other materials for customers in emergencies, special materials have been created and a portal (described below) for first responders is now available. 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. PG&E is also developing Public Awareness metrics.

PG&E is required to communicate with five different stakeholder audiences at certain frequencies.

1) **Affected Public** (Distribution customers) – Twice a year
   - Primary form of communication: Bill inserts
2) **Affected Public** (Landowners along transmission Right of Way, or 660' or potential impact radius (PIR) whichever is greater of centerline of pipe) – Every other year
   - Primary form of communication: Brochure
   - PG&E is preparing to send a brochure to the affected public in the third quarter of this year, making 2012 the third year in a row the company exceeded the required frequency
3) **Emergency Responders** – Once a year
   - Primary form of communication: Mail the emergency response guidelines and training scenario video, as well as conducting face to face workshops
   - PG&E has held over 150 workshops so far in 2012
4) **Public Officials** – Every three years
   - Primary form of communication: Mail Public Official Newsletter / magazine
   - PG&E has traditionally sent this once a year, exceeding the required frequency
5) **Excavators** – Once a year
   - Primary form of communication: Mail Excavation Safety magazine mailed
   - PG&E mailed more than 114,000 magazines this year, covering the entire state of California

- PG&E also attends two farm shows each year: World Ag Expo and the Ag Safe Conference

2. Emergency Preparedness and Response

PG&E Gas Operations has a dedicated Emergency Preparedness and Public Awareness (EP&PA) team to support coordination activities, training and communication with city/county/local first responders within PG&E's service territory. A primary function of this dedicated team is to provide pipeline and general safety training to local/state/volunteer first responders, as well as share the Gas Emergency Response Plan or GERP (Attachments 9a and 9b) with the appropriate community partners. A new Public Safety and Integrity Management team has been formed and is actively engaged in various facets of emergency preparedness planning. Responsibilities of this team 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.

GERP describes roles and responsibilities of PG&E's emergency response personnel and includes a single person that assumes command and designates specific duties for Supervisory Control and Data Acquisition (SCADA) staff and all other potentially involved company employees. In general, command will move to a higher level employee with increasing complexity as follows:

- If there is an event on the pipeline, the person initially in control in the Control Room is the Sr. Transmission Controller. This individual is very experienced and has access to all pipeline information including alarm data and volume and pressure data.
- If the event escalates, the Operations Emergency Center (OEC) in the division is activated and an incident commander is in place to manage the field operations and to coordinate with gas control.
- If it escalates further, the Emergency Operations Center (EOC) is activated and the incident commander of the EOC is the single person in charge.
- Co-location of control center (in first quarter 2013) will facilitate command and control and will allow all information from transmission control, distribution control, and gas dispatch to be in one place.

PG&E's Utility Standard EMER-6010S - Training and Exercising Gas Emergency Response Plans (Attachment 32) provides requirements for conducting training and exercises associated with gas emergency response including:

- Annual joint exercise between PG&E and relevant first responders for each gas storage and gas regulation facility;
- Annual exercises at each of PG&E's 18 divisions; and
- Emergency Management Organization annual exercise involving PG&E's gas transmission pipeline system.

These exercises may include read-through exercises, table-top exercises, games, drills, functional exercises and full scale exercises. PG&E's Utility Standard EMER-6010s also requires a multi-year exercising plan.

PG&E is constantly reviewing and improving emergency response procedures and institutionalizing them across Gas Operations as required by GERP.

3. First Responder and Customer Access to Pipeline Information

PG&E has launched a web portal within pge.com dedicated to first responders and residential customers. Access to training material, general mapping locations of gas transmission pipeline segments, 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 EP&PA team.

4. 911 Process

PG&E's 911 Notification Process (Attachment 33) 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)

PG&E has implemented geographical based north/south alignment of its gas system operators by operating console in order to improve focus on real time monitoring. At any given time, operators are now responsible for monitoring the northern service territory or the southern service territory, not both. 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 alarm filter based on priority, data type, and geographic location.

PG&E has also completed work with human factors consultants developing a new SCADA visual coding design, including use of color, text and symbols in graphic displays to present alarm status. The new design will meet the requirements of API 1165 (Graphic Standard, Recommended Practice for Pipeline SCADA Display) and is planned to be implemented in the last quarter of 2012.

PG&E is committed to building alarm triggering to be more predictive in order to further improve its public safety focus and enable PG&E to make timely notifications to 911 emergency centers. Enhanced SCADA alarming will continually be incorporated into PG&E's 911 Notification Process as PG&E progresses towards its goal of implementing a control room philosophy and strategy to ensure increased situational awareness, while enabling it to become predictive of, and responsive to, emergency operating conditions.

PG&E is now utilizing a new enterprise wide OSIsoft Pi historian system which is data base collection site for all gas SCADA data. This new system will be used for a variety of purposes beyond collecting historic data. For example, this new system will be the basis for information displayed on large control room video screens. Release of the new historian system now positions PG&E to prototype the feasibility of combination and composite alarming, and multi-site data analysis and alarming utilizing the expanding pressure and flow meter SCADA data, coupled with over a decade of historic stored data.

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. PG&E feels that the additional reliance on non-SCADA based information broadens its responsiveness to the 911 emergency centers.

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.

Additionally, PG&E has new mobile command units to better respond to natural gas or electric emergencies.

5. Response to Seismic Issues

PG&E's RMI – 04 and RMI- 04b (Attachments 34a and 34b) are currently being updated and describe PG&E's use of USGS data and identifies service areas that are potentially impacted. These zones are communicated to the Emergency Operations Center (EOC) to determine the extent of damage and to identify appropriate mitigation. The susceptibility to seismic activity and geotechnical conditions are reviewed annually, and updated to provide accurate response areas over PG&E's Service Territory.

6. Call Center

PG&E operates a call center round the clock to receive calls from customers or emergency responders. The call center is in immediate contact with pipeline operations to dispatch crews at the first sign of any issues identified as a threat to public safety or pipeline integrity.

7. Service Response

Gas Field Services and Response 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 (GSR) completes more than 700,000 gas service requests from customers each year. These requests include investigating reports of possible gas leaks classified as immediate response work, gas starts/stops, pilot relights, customer appliance checks, for atmospheric corrosion work, and regulator replacements.

In 2012, 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 responding to gas leak reports within 30 minutes 75 percent of the time upon notification.

Responding to emergency situations is one of PG&E's highest priorities so that an unsafe or potentially hazardous situation is not created. Responding to gas leak calls within the specified timeframe is crucial to public and employee safety and is regarded as an industry best practice. Benchmarking indicated that PG&E's new goals are consistent with industry best practices. The best in class utilities use automated dispatch systems, mobile data terminals, real-time Global Positioning System (GPS), backup on call technicians, use make safe procedures, and shift coverage of 24 hours a day seven days a week to meet their gas leak response metric.

Third Party Emergency Response Centers ("911") have a direct 911 line into PG&E's Dispatch Centers. They dial (888) 743-4911 and are connected 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.

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. TD-4110P-10 details procedures for investigating reports of inside gas leaks (Attachment 35).

There are a number of factors that may involve dispatching a Maintenance & Construction (M&C) crew for response. Some of those factors may include:

- 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 a 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, maintenance and construction crews are dispatched at the same time as a GSR.

K. TOXICOLOGY TESTING

PG&E has recently updated its guidelines and procedures related to DOT Drug and Alcohol Testing after an accident. The requirement is set forth below:

When is testing required?

- *Fatality or personal injury requiring admission to and an overnight stay in a hospital.*
- *Estimated property damage of $50,000 or more, including loss to the company and others, but excluding cost of gas lost.*
- *Unintentional estimated gas loss of 3 million cubic feet or more. Use Attachment 2 to Utility Procedure TD-4413S –Gas Event Reporting Requirements to determine if this gas loss criterion has been reached for pipeline punctures and complete severing of the pipeline.*
- *An event that results in an emergency shutdown of a liquefied natural gas (LNG) facility.*
- *Rupture or explosion, fire, loss of service, evacuation of people in the area, involvement of local emergency response personnel (e.g., fire, police, ambulance).*

- *All explosions, except those in areas where there is no gas service or where it is immediately clear that natural gas did not contribute to the explosion.*

Time Limit to Perform Testing

If any of the above apply, DOT drug testing is required for all covered personnel involved at the time of the incident/accident. Testing is required within 2 hours of incident/accident, but not to exceed 8 hours afterward. If the time to administer alcohol testing exceeds 2 hours, the reasons why the test was not promptly administered are documented.

PG&E will be revising its procedures to comply with regulations by PHMSA pursuant to amendments to the Pipeline Safety Act which require that as of June 2013, accident or incident notification is to occur at the earliest practicable moment following confirmed discovery of an accident or incident and no later than 1 hour following such confirmed discovery.

All DOT leaders are required to complete DOT training every 2 years. In addition, employees are provided with checklists as quick reference guides.

In addition to providing training to DOT covered employees and leaders, PG&E provides training to its collectors on an annual basis

L. 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 36. Additionally, PG&E has recently implemented a new Self Reporting Process.

In compliance with a recent CPUC requirement (ALJ-274), PG&E is reaching out to employees at all levels of the organization and asking that they help identify gaps and non-compliance items. To date, numerous items have been raised and self-reported to the CPUC and in doing so has allowed PG&E to identify and make system wide improvements. Gas Operations is encouraging 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, Gas Operations is leveraging the CPUC's recent "self reporting" requirement contained within ALJ-274. A key component of improving overall results is to identify gaps in current performance and then effect actions to remedy those gaps throughout the organization. ALJ-274 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. PG&E quickly adopted this requirement into the Gas Operations organization and was the first utility to report a non-compliance item.

As of the end of May, 2012, PG&E has made 15 self reports on a variety of topics. This success 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.

M. QUALITY AND IMPROVEMENTS

PG&E is increasing the focus on quality starting with the recent formation of a dedicated Quality and Improvement (Q&I) department within Gas Operations. At a high level, the Q&I department is responsible for centralized Quality Control (QC), Quality Assurance (QA), and Work/Human Performance Improvement (W&HPI) activities.

The QC activities include performing random quality verifications through field assessments of completed work. PG&E currently has three fully operational QC programs for Leak Survey, Leak Repair, and Locate and Mark. This will be expanded through the development of additional QC programs in additional areas. An example of a new QC programs under development in 2012 is a Work Verification (Re-Dig) program which focuses on construction. This QC program will target installation and repair work performed by PG&E employees and contract personnel. A post-installation verification (Re-Dig) will be performed shortly after installation or repair work is completed for the purpose of verifying the work performed on the buried facility is fully compliant with all governing standards and work practices. This also includes a quality evaluation of the documentation supporting the field work.

The QA activities include performing quality reviews upstream of completed work to provide assurance of a quality end product. QA reviews include audits of PG&E's processes and programs. QA responsibilities also include conducting assessments to provide recommendations for improvement and building an overarching Corrective Action Program for Gas Operations which complies with the PAS 55 certification requirements.

The W&HPI activities are focused on providing an independent review of information, incidents, and events in order to recommend where human performance based improvements can be made within Gas Operations. One of the near term W&HPI efforts is to develop a more formalized employee feedback system as a mechanism for employees and contractors to easily, and anonymously if they choose, submit Gas Operations related concerns, questions, ideas, and general feedback.

N. METRICS AND GOALS

PG&E's 2012 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. PG&E has 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 of customer satisfaction and financial performance are each weighted 30 percent. This change reinforces the importance of safety.

Attachment 37 shows some of the current key gas operating metrics that PG&E tracks.

PG&E Gas Safety Plan Appendices and Attachments		
Attachment No.	**Report Section**	**Description**
(Appendix A)		PG&E Gas System Miles
(Appendix B)		PG&E Project/Initiative Timeline
1	Executive Summary	NTSB Safety Recommendations – Update on PG&E's Actions
2	Regulatory Description	Mapping showing how PG&E is addressing each element of Public Utility Code §§ 961 and 963 for its gas transmission and distribution facilities within this Plan
3	Gas Organization	22 primary processes identified for Gas Operations
4a	Employee and Contractor Feedback	Workforce Feedback and Input Log
4b	Employee and Contractor Feedback	Contractor Survey Results
5	Employee and Contractor Feedback	Gas Technical Teams Current Roster
6	Standards, Policies and Procedures	Gas Distribution Maintenance Manual – TD 4380M (Index only)
7	Standards, Policies and Procedures	Gas Distribution Operations Manual - TD 4381M (Index only)
8	Standards, Policies and Procedures	Gas Transmission Standards Manual (Index only)
9	Standards, Policies and Procedures	Gas Emergency Response Plan (GERP) Part 1 (Index only)
10	Standards, Policies and Procedures	Gas Emergency Response Plan (GERP) Part 2 (Index only)
11	Standards, Policies and Procedures	List of additional subject matter manuals under development
12	Contractor Standards/OQ	PG&E's OQ Plan - Part 1, Part 2, and Supplement to §1.9
13	Contractor Standards/OQ	OQ Covered Tasks List
14	Contractor Standards/OQ	UO Standard S4450 - Operator Qualification Program
15	Gas Transmission Control	Map showing assignment of operator responsibilities
16	Operations Clearance Procedures	Draft Transmission Clearance Procedure
17	System Pressure and Capacity	Utility Standard TD-5429S - Gas Transmission and Distribution Systems Capacity Planning Requirements
18	System Pressure and Capacity	TD-5429P-01 - Gas Transmission and Distribution Systems Capacity Planning Procedures
19	Transmission Integrity Management	RMP-01 through -13 (Listing only)

	Program	
20	Transmission Integrity Management Program	RMP-06 - PG&E's Integrity Management Procedure
21	Class Location	Utility Procedure TD-4127P-02 – Conducting System-Wide Class Location Review
22	Class Location	Utility Procedure TD-4127S – Class Location Determination and Compliance Requirements
23	DIMP	RMP-15 – Gas Distribution Integrity Management Program
24	DIMP	RMI-G - DIMP Probabilistic Validation Process
25	DIMP	Annual report to the Office of Pipeline Safety and CPUC
26	DIMP	Utility Bulletin TD-H-10B-001 – HPR Atmospheric Corrosion Inspection Project
27a	DIMP	Utility Bulletin TD-4412B-009 – Dry-Bore Inspection Requirements
27b	DIMP	Utility Procedure TD-4412B-009 – Dry-Bore Inspection Methods Using an Inspection Camera System
28	DIMP	Isolated Steel Services Quarterly Report – Fourth Quarter 2011
29	DIMP	UO Standard S5000 – Gas Distribution Emergency Shutdown Zones
30	Leak Survey	UO Standard S4110 – Leak Survey and Repair of Gas Transmission and Distribution Facilities
31a	Leak Repair	Utility Standard TD-6434S – Gas Leak and Odor Response
31b	Leak Repair	Utility Procedure TD-6434P-01 – Gas Leak and Odor Investigation Procedure
32	Emergency Preparedness and Response	Utility Standard EMER-6010S – Training and Exercising Gas Emergency Response Plans
33	911 Process	Gas Control Room Process – 911 Notification Process
34a	Response to Seismic Issues	RMI-04B – Gas Distribution Earthquake Plan and Response Procedure
34b	Response to Seismic Issues	RMI-04 – Gas Transmission Earthquake Plan and Response Procedure
35	Service Response	Utility Procedure TD-4110P-10 – Inside Gas Leak and Odor Investigation
36	Compliance and Reporting	List of Compliance Reports to Regulatory Agencies
37	Metrics	Metrics Table

APPENDIX A

PG&E Gas System Miles

Transmission (Includes 4.5 miles of gathering)	Miles		
	PG&E	**StanPac**	**Total**
Steel	5747.5	54.6	5802.1
Wrought Iron	0.8	0	0.8
Total	**5748.3**	**54.6**	**5802.9**

Distribution	Miles
Steel	21,017
Plastic (Polyethylene)	21,177
Cast/Wrought Iron	115
Copper	0
Total	**42,309**

APPENDIX B

Project/Initiative	Time Line			
	2012	2013	2014	2015
PSEP				
Pipeline Replacement	Phase 1			Phase 2
Strength Testing	Phase 1			Phase 2
Automated Valve Program	Phase 1			Phase 2
MAOP Validation				
Safety with Customers and First Responders				
Transmission Programs				
Transmission Integrity Management Program	2011 GT&S levels			2015 GT&S
In Line Inspection	2011 GT&S levels / PSEP Phase 1			2015 GT&S
Transmission Pipeline Replacement	2011 GT&S levels			2015 GT&S
Centerlining	2011 GT&S levels			2015 GT&S
Direct Assessment	2011 GT&S levels			2015 GT&S
Patrolling and Monitoring	2011 GT&S levels / PSEP Phase 1			2015 GT&S
Gas Transmission Asset Management Project (Mariner)	PSEP Phase 1			2015 GT&S
Distribution Integrity Management Program				
Distribution Pipeline Replacement	2011 GRC levels		2014 GRC	
High Pressure Regulators Inspections and Maintenance	2011 GRC levels		2014 GRC	
Cross Bored Program	2011 GRC levels		2014 GRC	
Copper Service Replacement	2011 GRC levels		2014 GRC	
Aldyl-A	2011 GRC levels		2014 GRC	
Plastic Tee Cap Repair Program	2011 GRC levels		2014 GRC	
Meter Protection	2011 GRC levels		2014 GRC	
Main Replacment for Low Pressure to High Pressure			2014 GRC	
Atmospheric Corrosion	2011 GRC levels		2014 GRC	
Isolated Services	2011 GRC levels		2014 GRC	
Valves – Emergency Shutdown Zones			2014 GRC	
Gas Distribution Asset Management Project (Pathfinder)			2014 GRC	
Other Key Maintenance Programs				
Leak Survey	2011 GRC/GT&S levels		2014 GRC / 2015 GT&S	
Leak Repair	2011 GRC/GT&S levels		2014 GRC / 2015 GT&S	
Damage Prevention	2011 GRC/GT&S levels		2014 GRC / 2015 GT&S	
Locate and Mark	2011 GRC/GT&S levels		2014 GRC / 2015 GT&S	
Dig In Mitigation	2011 GRC/GT&S levels		2014 GRC / 2015 GT&S	
Pipeline Patrol	2011 GRC/GT&S levels		2014 GRC / 2015 GT&S	
Cathodic Protection	2011 GRC/GT&S levels		2014 GRC / 2015 GT&S	